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Power from shore to Utsira High

Evaluation of the project's cost efficiency and its effect on Norwegian and European emissions

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Master thesis in Energy, Natural Resources and the Environment

NORWEGIAN SCHOOL OF ECONOMICS

Preface

This thesis is written as a part of the master profile Energy, Natural Resources and Environment at Norwegian School of Economics. The work has led to in-depth knowledge about the economic, environmental and political aspects of power from shore (PFS) as a climate measure. The process has been an educational and exciting journey, providing useful experience and knowledge to be applied in our future careers. We early decided that we wanted to write about a topic that is relevant for the oil and gas industry in Norway, but it was our supervisor Rögnvaldur Hannesson who gave us the idea about PFS. Despite high media coverage, surprisingly few studies on PFS have been conducted and we have the impression that most students at NHH have limited knowledge of the topic. An investment decision on a PFS system on Utsira High is imminent and will highly affect future emissions from the Norwegian Continental Shelf. Focusing on Utsira High was therefore a natural choice as this currently is one of the major topics in the debate around PFS.

We would like to thank our supervisor Rögnvaldur Hannesson for his extraordinary advice and feedback that have helped us throughout the process of writing. After five years at the Norwegian School of Economics, we would also like to thank our lecturers, fellow students, student association and everyone else who have contributed to making this a great experience.

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Executive summary

This thesis evaluates the cost efficiency of a power from shore (PFS) project on Utsira High and its effect on Norwegian and European greenhouse gas emissions. The Ministry of Finance's framework for economic analyses is applied in order to calculate and determine the project's costs for the Norwegian economy and its national emission reductions, leading to the abatement cost. The abatement cost is compared with the expected price of EU ETS allowances in order to determine the cost efficiency of the project. Furthermore, the effect on European emissions is evaluated by applying relevant knowledge of the Nordic and European power markets and by referring to recent studies in the area.

We have calculated an abatement cost of NOK 1163.37 per ton CO_2 reduced. EU ETS allowances have a current price of NOK 28.66, with an estimated value of NOK 305 in 2020. We therefore conclude that the project is not a cost efficient measure for Norway to fulfill its international climate commitments. Although the analysis shows that the PFS project will reduce national emissions by 31.91 million tons CO_2, we show that the project is unlikely to have any effect on European emissions.

In order to reach non-binding national goals specified in the Climate Agreement of 2012, Climate Cure 2020 (2010) states that all measures with abatement cost up to NOK 1100 per ton CO_2 must be implemented. As the abatement cost of the PFS project is close to this cost, the authorities may press for implementation if the national goals become binding commitments in the future.

Table of Contents

1. Introduction

1.1 Motivation

Power from shore to offshore installations is an important topic in Norwegian climate policy. This is due to the measure's high potential to reduce greenhouse gas emissions from the Norwegian continental shelf. The recent discovery of the Johan Sverdrup field at Utsira High has again shed light on the debate of power from shore as a climate measure. An investment decision is expected to take place during the fall of 2013. The Energy, Natural Resources and the Environment (ENE) profile at the Norwegian School of Economics (NHH) has provided knowledge and inspiration to evaluate a power from shore project on Utsira High from an objective view.

Due to the project's important implications for the Norwegian economy and Norway's participation in EU ETS, we find it relevant to evaluate the cost efficiency of the project. As Norway is a part of the Nordic and European power markets, we find it puzzling that the majority of reports only focus on national emissions when considering the global nature of GHG emissions. The amount of information and analyses available to the public on the power from shore topic is limited, encouraging us to provide useful information and arguments which can be applied by stakeholders, decision makers and other readers with a general interest in the area.

1.2 Purpose of thesis and statement of problem

The main purpose of this thesis is to evaluate the cost efficiency of a power from shore project on Utsira High and its corresponding effect on national and European emissions. We explain why power from shore is a relevant climate measure in Norway and if it will result in profitability for the overall economy. Considering the global nature of greenhouse gas emissions and Norwegian commitments through the Kyoto Protocol, we also find it necessary to analyze the effect on European emissions. Power from shore addresses political, environmental and economic aspects. This thesis seeks to tie these aspects together in order to better understand the total implications of the project.

It is obvious that the PFS project will reduce national emissions. However, it is less obvious if the project is cost-efficient for the Norwegian economy or whether it will have any effect on European emissions. The formal statement of thesis problem becomes:

1. **Is a PFS project on Utsira High a cost efficient climate measure to reduce Norwegian emissions?**
2. **What is the PFS project's effect on European emissions?**

In case our analysis shows that a PFS project on Utsira High is cost-efficient and at the same time reduces European emissions, we will recommend that the project is implemented. We will base the recommendation on current binding commitments through the Kyoto Protocol and Norway's participation in the EU ETS. However, it is important to emphasize that the national long term goals of ambitious climate policy specified in the Climate Agreement of 2012 may become binding commitments in the future. In this hypothetical situation, it may be argued that an evaluation of the PFS project on Utsira High should be based on these commitments instead.

1.3 Structure of thesis

Chapter 2 presents relevant background material in order to fully understand why power from shore (PFS) is considered as a climate measure in Norway. Chapter 2.1 starts with the fundamental reasons for climate policies and pricing of emissions. Relevant theory of how to price emissions is described in chapter 2.2 while international and Norwegian climate policies are described in chapter 2.3 and 2.4 respectively. Chapter 2.5 gives an overview over the main sources of Norwegian emissions before chapter 2.5 focuses on the petroleum industry and why PFS is considered a relevant climate measure in Norway. Chapter 2.6 serves as relevant background for chapter 5, and focuses on the main aspects of the Norwegian power grid and Nordic and European power markets. Chapter 3 describes the method and framework applied in our analysis, while chapter 4 presents the analysis, divided into different steps in compliance with the Ministry of Finance's framework for economic analyses. While the analysis in chapter 4 focuses on cost efficiency and gives an estimate of abatement cost and reduced emissions in Norway, chapter 5 focus on the PFS project's effect on European emissions. Chapter 6 provides concluding remarks based on findings in chapter 4 and 5.

2. Background

2.1 Reasons for climate policies and pricing of emissions

Greenhouse gases (GHGs) are gases present in the atmosphere which effectively absorb thermal infrared radiation emitted by the Earth's surface, the atmosphere itself and by clouds. The greenhouse gases reduce the loss of heat into space and traps it within the surface-troposphere system, known as the greenhouse effect (IPCC, 2013). The primary greenhouse gases in the atmosphere are water vapor (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and ozone (O_3). GHGs differ from most pollutants because their effect on Earth's climate and environment is identical, independent of where the emission takes place. The GHGs disperse rapidly in the atmosphere, and the greenhouse effect is argued to increase with the atmosphere's concentration of the gases (IPCC, 2013). The emissions have a global effect on the environment, contrary to other pollutants which rather have a local impact.

Henceforth, whenever this thesis mentions CO_2 or GHGs, it is used as a synonym for CO_2 equivalents (CO_2e). Furthermore, this thesis is careful on using the word *pollutants* to describe GHG emissions, as GHGs are natural components in the earth's ecosystem and essential for a stable climate. The Intergovernmental Panel on Climate Change (IPCC) identifies several GHGs that are ranked in terms of an index that measures their global warming potential (GWP) relative to carbon dioxide for a 100 year time horizon. Table 2.1 lists six GHGs in terms of GWP which IPCC and the United Nations Framework Convention on Climate Change (UNFCCC) have identified as the largest contributors to global warming. Helping to understand the index, one ton of Methane has 25 times larger global warming potential than one ton[1] of Carbon dioxide due to higher absorption of outgoing radiation.

[1] For simplicity, one *ton* refers to one *metric ton* in this thesis.

Global Warming Potential of GHGs listed by IPCC

Greenhouse gas	Global Warming Potential (GWP) over 100 years
Carbon dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous Oxide (N_2O)	298
Hydrofluorcarbons (HFCs)	124-14,800
Perfluorcarbons (PFCs)	7500-12,200
Sulphur hexafluoride (SF_6)	22,600

Table 2.1 Source: IPCC, 2007

It is important to stress the distinction between the natural greenhouse effect and the enhanced greenhouse effect. Life on Earth as we know it is entirely dependent on the natural greenhouse effect. Without it, the average temperature would be around −18°C, compared to today's average of +15°C (Le Treut et. al, 2007). The enhanced greenhouse effect is argued to be man-made and is the main reason for the emergence of worldwide climate policies at the end of the 20st century. CDIAC (2013) states that the burning of fossil fuels since the beginning of the Industrial Revolution has contributed to a 40% increase in the concentration of CO_2 in the atmosphere, from 280 ppm to 397 ppm(CDIAC, 2013) (ESRL, 2008). The natural flow of GHGs in and out of the atmosphere are enormous, making the human contribution of 5% (MacKay, 2008)[2] from burning of fossil fuels seem insignificant, a fact often used by skeptics. However, MacKay (2008) argues that this is highly misleading and irrelevant. The natural flows have been in balance and kept the concentration stable for millennia, canceling themselves out. Human emissions through burning of fossil fuels are a relatively new factor in the equation, creating a new flow of

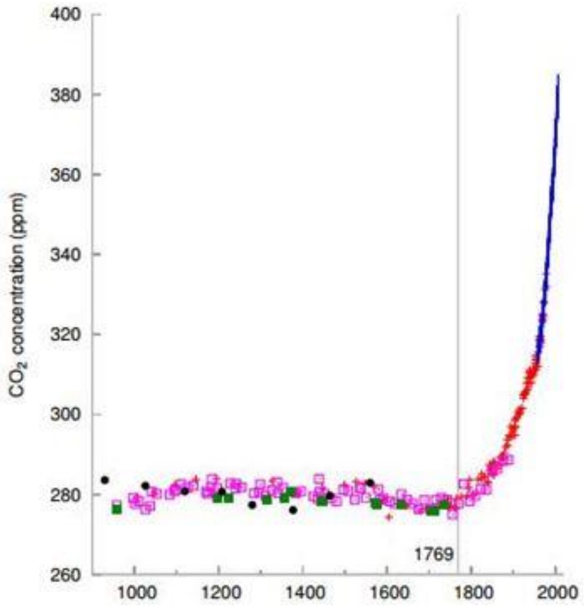

Figure 2.1 - The graph shows carbon dioxide (CO2) concentrations in parts per million (ppm) for the last 1100 years. Source: MacKay, 2008

[2] The exact number has different estimates from different sources. However, the human contribution of GHGs into the atmosphere seems to be around 3-5%. This thesis use 5% from MacKay (2007).

carbon that is not cancelled out (MacKay, 2008). The argument is that natural removal processes on land and in the oceans cannot keep pace with the extra input of emissions, leading to an accumulation in the atmosphere. The concentration of GHGs in the atmosphere have not been at a higher level for 650 000 years (Klif, 2011).

This thesis will not further discuss the different opinions about the *effects* of carbon building up in the atmosphere. However, IPCC shows that it probably will have global consequences for the climate through *global warming* and has become the background for international negotiations and the well-known Kyoto Protocol.

The accumulation of CO_2 in the atmosphere and the believed consequences that may follow has led to a number of international negotiations and targets. The thesis will focus on the most prominent institutions and agreements leading to the Kyoto Protocol and the European carbon market (EU ETS). Together with national targets, they are the primary drivers for Norwegian investments in emission reducing measures. Before this, relevant theory of externalities and ways to correct market failure is needed to understand the authorities' main tools to reduce emissions.

2.2 Externalities and ways of correcting market failure

Occasionally, markets need to be regulated. Policy makers strive to establish fair and efficient regulations to fix market failures. When the authorities regulate inefficient markets, their toolbox of public measures is often referred to, containing everything from taxes, fees, prohibitions, regulations of consumption, production or resources; subsidies to production, employment, investments or other purposes; public production and supply; customs and export subsidies (Norman, Orvedal, 2010). The following section focus on externalities and the economic theory behind correcting market failures.

2.2.1 Externalities

Externalities can arise between producers, between consumers, or between consumers and producers. They can be negative - when the action of one party imposes costs on another party - or positive - when the action of one party benefits another party (Pindyck and Rubinfeld, 2005). The following definition is often used for an externality: *An action taken by either a producer or a consumer which affects other producers or consumers, but is not accounted for in the market price* (Pindyck and Rubinfeld, 2005).

Since externalities are not reflected in market prices, they can be a source of economic inefficiency. The following section emphasizes the case of negative externalities since this thesis mainly focuses on CO_2-emissions[3]. Figure 2.2 illustrates the costs of externalities. With negative externalities, a firms' supply curve does not represent the true cost of production, denoted *marginal social cost* (MSC). It means that we have a situation where the MSC of production is higher than the marginal cost (MC) of production. The difference between the curves is the marginal external cost (MEC). Considering this cost, a profit-maximizing company will produce a higher quantity than the efficient output. As described in figure 2.2, the profit-maximizing firm produces q_1 units when receiving a price equal to P_1. At this level of output, P_1 does not reflect the social costs. If prices are to reflect these costs, the price has to be increased or the quantity reduced. The simplest solution to solve the externality problem with perfect information is to introduce a Pigouvian tax.

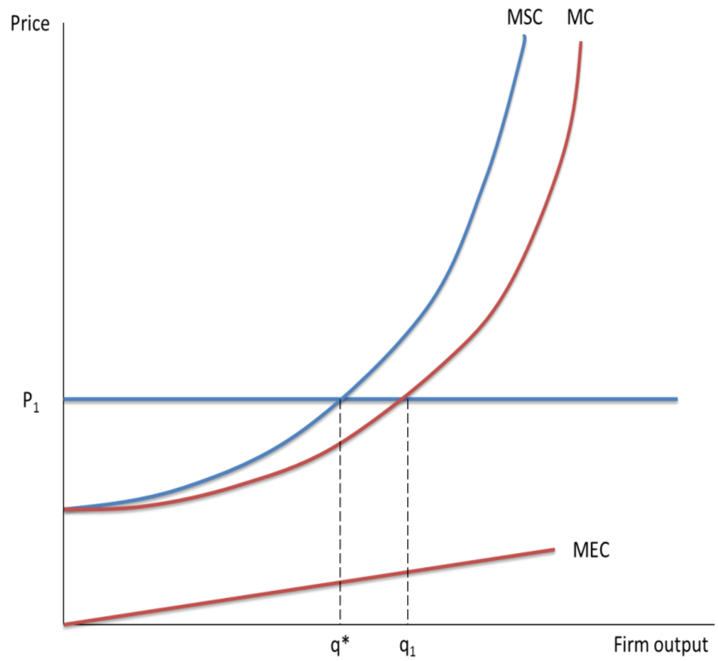

Figure 2.2 Source: Pindyck and Rubinfeld, 2005

2.2.2 Pigouvian tax, basic economic theory

A Pigouvian tax can be imposed on the firm to avoid an inefficient outcome, illustrated in figure 2.2. Arthur C. Pigou was the first to point out the possibility to correct external effects with a tax directly on the activities that cause negative externalities. Contrary to other taxes, these taxes do not lead to economic inefficiency and loss. They rather lead to economic gains by correcting market failures. Other taxes lead to unwanted shifts in resource allocations, causing economic loss (Norman, Orvedal, 2010). A Pigouvian tax adds a tax t* per unit of emissions. The market solution is then brought closer to the optimal solution since the tax corrects the negative externality. Generally these taxes are more efficient when authorities have perfect information about the externality. Adding the correct tax on the

[3] As mentioned, man-made CO_2-emissions and GHGs are generally related to global warming and are hence referred to as a negative externality.

source leads to the competitive market equilibrium. As illustrated in figure 2.3, the tax is equal to the marginal external cost (MEC). The tax results in an upward shift in the firms' MC curve. The MSC curve is equal to the firms MC plus the tax. These changes result in a shift of the firm's output. The firm will now produce q* units, which reflect the optimal solution[4]. However, the challenge is to find the correct tax. A Pigouvian tax should not be mistaken for a fee; with perfect information a Pigouvian tax serve as a direct regulation which directly taxes the source. This implies that we know the outcome of the regulation, while fees are set with less market information and the outcome is correspondingly more uncertain.

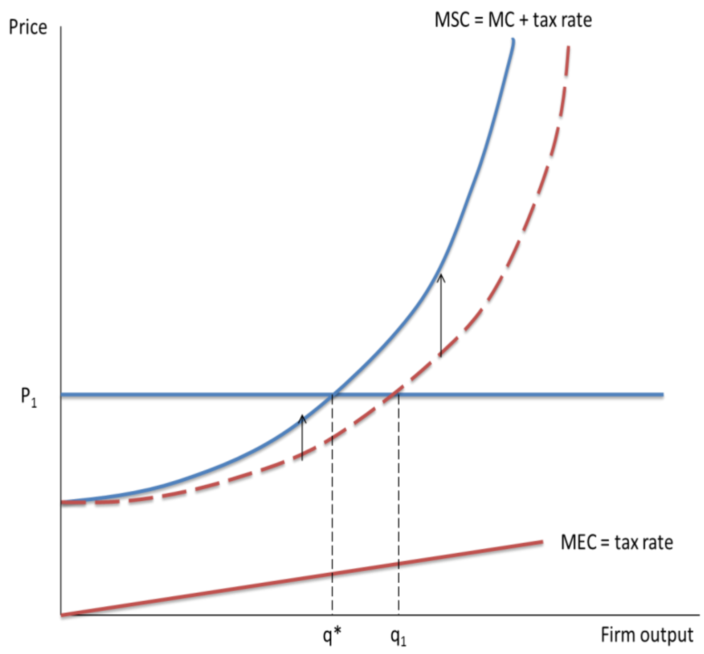

Figure 2.3 Source: Pindyck and Rubenfeld, 2005

2.2.3 Direct regulation

To understand how to deal with market failures we need to know what measures we have, and how they can be applied. We differentiate between direct and indirect measures.

Direct measures on emissions or market participants are prohibitions, injunctions or quotas; it can be defined as *telling the participant what he should or must do*. This means that the government directly regulates the amount of emissions from the sources. Direct measures also tend to incur administrative costs related to the monitoring part of the measure. Examples of direct measures can be; Hydro-Sunndalsøra is not allowed to emit more than 13 kg of fluoride per hour, a car must have a catalyst and you are not allowed to use studded tires in certain areas (Mathisen, 2009). Direct measures addresses the problem directly, but they are on some occasions not cost-efficient since they enforce a behavior from the participant in contrast to letting the participant decide the most efficient behavior. If the

[4] A correctly adjusted tax will equal the cost of the externality in the optimal solution point, such that optimal production is achieved.

government enforced electrification of all Norwegian offshore installations this would have been a direct measure which addressed the problem directly since it would have led to the desired reduction in emissions necessary to reach national emission targets. For this measure to be cost-efficient it depends on whether the measure is the cheapest way to reduce national emissions or not. Today it is mandatory for all new installations on the Norwegian continental shelf to study the cost of electrification. This regulation will lead to cost efficiency if installations are electrified when the solution is profitable and if enough installations are electrified in order to reach the emission targets (Førsund & Strøm, 2000). Generally, direct measures are most applicable when the authorities have perfect information about marginal external costs and market participants.

2.2.4 Indirect Regulation

Indirect measures can be referred to as the market mechanism and are supposed to give the market participant an incentive to choose the optimal solution. Examples of indirect measures are fees per unit of emission, a subsidy, deposits on for example cars and bottles or tradable emission permits (Mathisen, 2009).

2.2.5 The relationship between fees and quotas

The following part will focus on the relationship between marginal social costs (MSC) and firms' marginal cost of abatement (MCA) and how the use of fees or quotas can lead to the optimal level of emissions. An illustration is given in figure 2.4. Consider a firm that produces a widget in a competitive market. However as a consequence of the widget production the firm emits pollutants. The firm can reduce its emissions, but only at a cost.

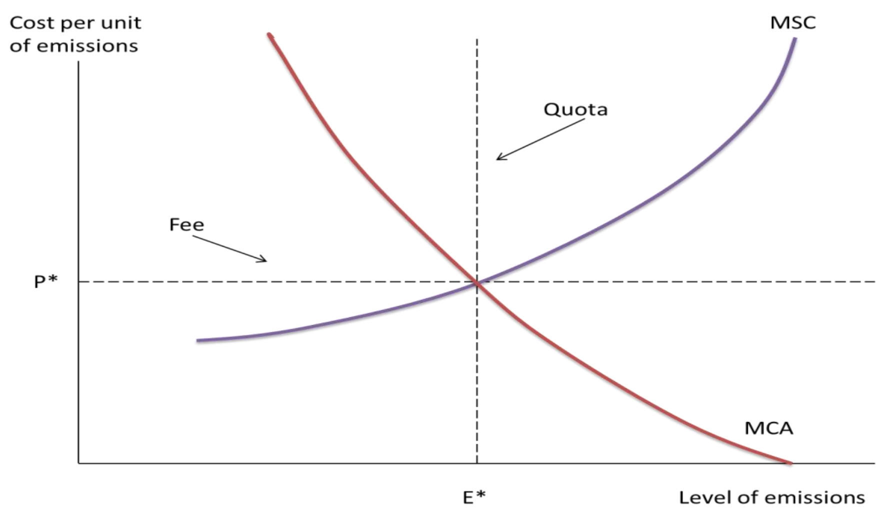

Figure 2.4 Source: Pindyck and Rubinfeld, 2005

Assuming that the firm is profit-maximizing, the preferred amount of emissions has been chosen. The marginal social cost of emissions gets higher as the externality becomes more extensive, resulting in an upward sloping MSC curve. The firm's MCA curve is downward sloping, indicating that the cost of reducing emissions is low when the level of emissions is high and vice versa. Figure 2.4 shows two different tools which can be used to encourage participants to reduce emissions; fees and quotas. By levying a fee equal to P* per unit of emissions, the polluter will minimize his costs by reducing the emissions to the desired emission level E*. This is because at all emission levels above E*, the MCA is less than the emission fee. However at emission levels below E* the MCA is higher than the emission fee, leaving the polluter in a situation where he prefers to pay the fee rather than further reduce his emissions. Another tool to achieve the optimal level of emissions is to implement an emissions quota, specifying a fixed amount on emissions. If the polluter exceeds the limit he will be heavily penalized. In figure 2.4 the quota-level is equal to E* not allowing the polluter to emit more than E* emission units. The polluter is now faced with a situation where he has to implement abatement measures, and as a consequence causing a rise in the firm's average costs. The polluter will only enter the market if the price of the product is higher than the average cost of production, including the abatement cost.

The relative advantage of quotas and fees depend on the amount of information available to policy makers and on the actual cost of controlling emissions (Pindyck & Rubinfeld, 2005). It is often the case that the emissions fee achieves the same level of emission reduction at a lower cost than the equal per-firm emissions quota. There are two main reasons for why a fee often is preferable to a quota:

1. When quotas must be applied equally to all firms, a fee achieves the same total reduction at a lower cost. By levying a fee, firms with low MCA will reduce to a lower cost than firms with high MCA. This brings a greater degree of cost efficiency than quotas.
2. Fees give strong incentives to install equipment that allows the firm to reduce emissions even further than with a quota.

However, if we face a situation with a steep marginal social cost curve combined with a relatively flat marginal cost of abatement curve, a quota becomes the preferable measure to achieve the wanted reductions at a lower cost than the fees. In a situation with incomplete information, quotas offer more certainty about emissions levels, but the cost of abatement becomes uncertain. Fees will generally bring certainty to the cost of abatement but leave the reduction level of emissions uncertain.

2.2.6 Transferable Emissions Permits

This part introduces a third tool to correct market failures, and serves as an introduction and background theory to the European Union Emissions Trading Scheme (EU ETS) which will be discussed in later sections. The focus will be on a *cap and trade* system as in the EU ETS due to its relevance for this thesis. With imperfect information, neither fees nor quotas are likely to result in an efficient outcome. In this situation, transferable emissions permits are better suited. In short, it is a system of tradable permits allocated among firms, specifying the maximum level of emissions that can be generated (Pindyck & Rubinfeld, 2005). The number of permits, the cap, corresponds to the desired level of emissions. Permits are tradable, and can be bought and sold between the market participants, in effect creating a market for externalities. This market approach is appealing because it combines some of the advantageous features of a system of quotas with the cost advantages of a fee system (Pindyck & Rubinfeld, 2005). The cap reflects the quota and the trade allows abatement to be achieved at the lowest cost, reflecting the effect of fees.

In a cap and trade system, the authorities auction a fixed number of emission permits to the bidding companies. Companies also have the possibility to trade with each other. In the EU ETS, a tradable permit is equivalent to one ton of CO_2. They must surrender enough permits to cover their own emissions. If a company reduces its emissions, it can either keep the spare permits to cover future needs or sell them to other companies. In theory, this flexibility leads to cost-efficient emission cuts. The emissions are reduced where it is cheapest to do so. However, the authorities decide the size of emission cuts by determining the total distribution of permits, the cap (Cicero, 2008). The following example will help to understand the simple mechanisms of tradable permits in a cap and trade system when there are no distortions. It can be applied to countries as well as companies:

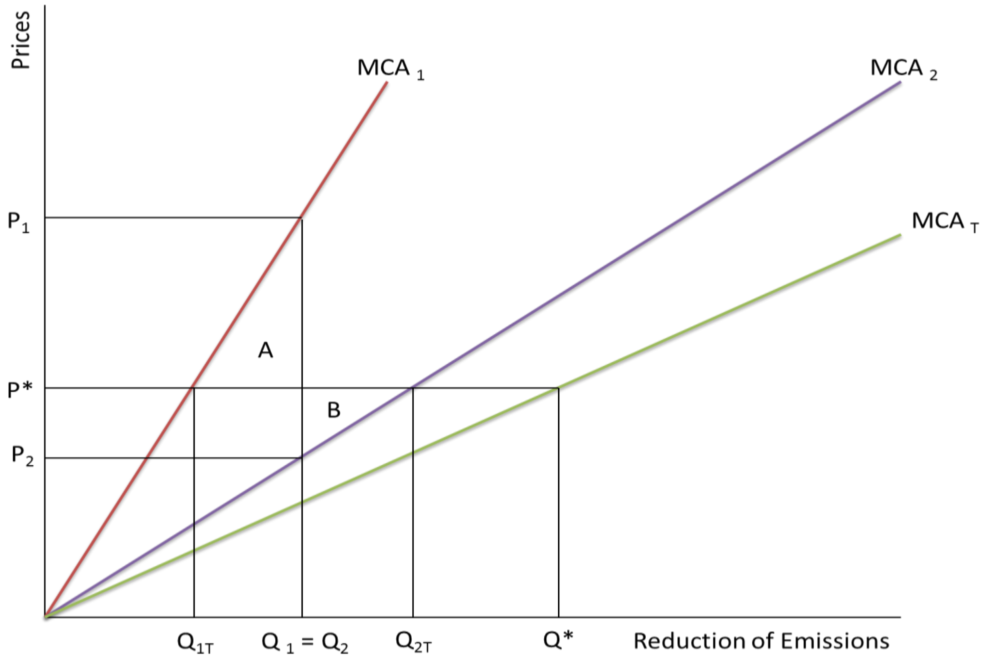

Figure 2.5 Source: Babiker, Reilly, Viguier, 2004

In figure 2.5 we find the marginal abatement cost of country 1 and country 2 respectively as the upward sloping curves MCA_1 and MCA_2. This figure operates with an inverted X-axis and the MCA curves are therefore not downward sloping as previous figures. Initially, carbon emissions are constrained and emissions have to be reduced by Q* without trading. The initial solution therefore brings a paired reduction for the two countries (Q_1 and Q_2) such that $Q_1 + Q_2 = Q^*$ and $Q_1 = Q_2$. The slopes of the MCA curves illustrate that the marginal abatement cost is higher in country 1 than in country 2 (At any given quantity, $P_1 > P_2$). Given this condition, the initial solution where $Q_1 = Q_2$ will be more costly for country 1 than for country 2.

Let us assume that an international trading regime is in place. The required reduction level between the countries is still given by the quantity pair labeled Q*. In the new regime, country 1 reduces emissions by Q_{1T} and buys emission permits. Country 2 reduces emissions by Q_{2T} and sells permits. The abatement cost[5] P* applies in both countries. Both countries are better off in the trading regime compared to a regime with no trading. Net income gains for country 1 and country 2 are area A and area B respectively (Babiker, Reilly, Viguier, 2004).

[5] The marginal abatement cost will in an international emission trading regime be reflected in carbon prices

The same allocation and cost efficiency as in figure 2.5 could have been achieved with the implementation of a Pigouvian tax. In a growing economy, it is conceivable that Pigouvian taxes will have to be frequently adjusted. When there is a market for permits the price of an emission permit will rise automatically, reflecting the fact that the right to pollute has become scarce. In an inflationary economy, a permit is also more flexible than a tax. Without frequent adjustments of the Pigouvian tax, environmental quality will be eroded under a tax regime. The price of a permit will simply follow the general price level, and therefore be preferable to a Pigouvian tax (Folmer & Gabel, 2000).

This simple theory of the cap and trade system provides the necessary insight in order to understand the key elements of the EU ETS market. First, an introduction to international negotiations and Norwegian policies and are needed. Combined with knowledge from this part, we will then introduce the EU ETS.

2.3 International climate negotiations

Due to its major impact on Norwegian climate policies, knowledge about international climate negotiations is highly relevant for this thesis. This part focuses on the most important negotiations leading to the Kyoto Protocol, linking it to the EU ETS market. Together, the Kyoto Protocol and EU ETS lay the foundation for Norwegian commitments, targets and measures to reduce emissions. This section therefore serves as a background for the motivation of Norwegian policy makers and authorities to consider all alternatives in order to reach the targets. As described in following chapters, the petroleum industry has a large potential for emission reductions in Norway, one of the main reasons for considering power from shore (PFS).

There is a global mutual understanding that cooperation is necessary to effectively prevent and reduce effects of global warming. Since the end of the 1980’s, international negotiations have therefore been engaged to limit GHG emissions. An outline of the United Nations (UN) backed scientific body IPCC and the International Environmental Treaty UNFCCC serves as relevant background to the Kyoto Protocol (*The Protocol*) and today’s carbon market, the EU ETS.

2.3.1 IPCC

The Intergovernmental Panel on Climate Change was established in 1988 by The United Nations Environmental Program (UNEP) and the World Meteorological Organization (WMO). It is the leading international body for the assessment of climate change, established to provide the world with a clear scientific view on climate change and its potential environmental and socio-economic impacts. *"The IPCC reviews and assesses the most recent scientific, technical and socio-economic information produced worldwide relevant to the understanding of climate change"* (IPCC, 2013) However, it does not conduct any research or monitor climate related data or parameters. 195 countries are currently members of the IPCC. Although the work of the organization is policy relevant, it describes itself as policy-neutral (IPCC, 2013). The combination of politics and climate research lays the foundation for climate negotiations. IPCC published its first assessment report in 1990 which led to increased attention to the climate change and laid the foundation for The United Nations Framework Convention on Climate Change (UNFCCC).

2.3.2 UNFCCC

The United Nations Framework Convention on Climate Change is an international environmental treaty negotiated and opened for signature at the 1992 United Nations Conference on Environment and Development (UNCED) in Rio de Janeiro, also known as the *Earth Summit*. Its objective is *"Stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system"* (UNFCCC, 1992). The UNFCCC entered into force in 1994 and today has 195 Parties of the Convention[6]. The majority of UN member nations are included. The treaty establishes an agreement that developed countries should take the first step and pave the way with abatement measures in their own countries. It proposed that the emission level should stabilize at 1990-levels by the year 2000. However, the treaty is legally non-binding with no enforcement mechanisms and generally functioned as a foundation for existing and future international climate negotiations. It provides a framework for negotiating specific international treaties, called *"protocols"*, which may set binding limits on GHGs (NIMUN, 2013).

[6] Countries which have ratified the Convention.

2.3.3 The Kyoto Protocol

Agreements through the UNFCCC that entered into force in 1994, have led to 13 UNFCCC Conferences of the Parties (COP). During the 1996 COP-II in Geneva, Switzerland, the IPCC findings on climate change was accepted and legally binding mid-term targets was called for. After negotiations during the 1997 COP-III in Kyoto, Japan the Kyoto Protocol (*the Protocol)* on Climate Change was adopted and marked a significant breakthrough. The following COPs also negotiated the Protocol to establish legally binding obligations for developed countries to reduce their greenhouse gas emissions. Several years passed to establish and adopt detailed regulations on how the Protocol should be conducted, until reaching an agreement during the 2001 COP in Marrakech, Morocco (CICERO, 2010). 197 countries, including Norway and EU, have ratified the Protocol. A country with an emission reduction or limitation commitment under the Kyoto Protocol is called an Annex B Party[7]. The United States, with 36.1% of emissions from developed countries in 1990, has chosen not to participate (Klif, 2012). After the ratification of Russia, the Protocol entered into force on February 16th, 2005. The primary goal was to reduce emissions from developed countries with a minimum of 5% compared to 1990 levels during a time frame of five years between 2008 and 2012 (NOU, 2012), called the *first commitment period.* While the UNFCCC serves as a framework for agreements, the Protocol operationalizes them. The legal framework in the Protocol links it to the EU ETS market, giving each country a specified number of emission permits over specified periods. The number of permits is calculated as a percentage of the country's emissions in 1990. The EU ETS will be further described at the end of this part. If the Annex B Parties are unable to reduce emissions in their own countries, they alternatively have three flexible mechanisms that were developed during the COP-6 and COP-7 in 2001 (UNFCCC, 2012). The first mechanism uses a cap-and-trade system, while the second and third uses a baseline-and-credit scheme.

1. **International emissions trading**

   Emissions trading allow countries to sell excess capacity of permits to countries that are over their targets. Since carbon dioxide is the principal GHG, *trading carbon* has become common language. The tracking and trade of carbon is known as the *carbon market*.

[7] For a description of the different Annex classifications, see Appendix 8.1.

2. **Clean Development Mechanism (CDM)**

This mechanism allows a country to implement an emission-reduction project in developing countries (non-Annex B Parties) and earn saleable certified emission reduction (CER) credits. Each of these credits is equivalent to one ton of CO_2 which can be applied to meet the country's Kyoto target. Other than giving developed countries flexibility and cost-efficient options to fulfill their emission targets, it furthermore stimulates sustainable development.

3. **Joint Implementation (JI)**

This allows a country to earn emission reduction units (ERUs) from an emission reduction or emission removal project in another Annex B Party. Each ERU is equivalent to one ton of CO_2 which can be applied to meet its Kyoto target. This provides a flexible and cost-efficient option of fulfilling a part of the Kyoto commitments. The host party benefits from foreign investment and technology transfer.

The legal framework of the Protocol establishes that each party should reduce a part of their emissions in their home country. Reaching their targets solely by buying permits or obtaining CER and ERUs is not permitted. However, there is no upper limit on the amount of permits an Annex B Party can buy. It is therefore expected that a country would rather buy tradable permits if it is cheaper than national abatement measures. (CICERO, 2010).

"The Kyoto Protocol is seen as an important first step towards a truly global emission reduction regime that will stabilize GHG emissions, and can provide the architecture for the future international agreement on climate change" (UNFCCC, 2012). In other words, it is not the final strategy to combat climate change, but it sets the baseline for further development of the framework and commitments. There have been several negotiations and agreements since the Protocol entered into force in 2005. The most prominent ones are the *Bali Road Map* (2007), *Cancun Agreements* (2010), *UNFCCC Durban* (2011), and *Doha Climate Gateway* (2012). The latter led to an adaptation of the *Doha Amendment to the Kyoto Protocol*. This amendment led to new commitments for Annex 1 Parties to the Protocol who agreed to take on commitments in a second commitment period of 8 years from 1st of January 2013 to

31st of December 2020. The commitments are to reduce GHG emissions by at least 18% against the baseline of 1990. However, the composition of Parties in this period is different from the first, but Norway is included in both (UNFCCC, 2012).

This part will not further discuss the details of the Protocol and the later agreements. It is the fundamentals of the Protocol that are important in order to understand and comprehend the EU ETS and Norway's international commitments.

2.3.4 EU ETS

The European Union Emissions Trading Scheme (EU ETS) entered into force on the 1st of January 2005 as a result of the Kyoto Protocol. It is the first and largest international carbon emission trading scheme. EU Allowances (EUAs) are the tradable units under the EU ETS. The price is determined by market forces of supply and demand, and depends on the amount of allowances in the market and the abatement costs of companies (Klif, 2012). Around 45% of the total GHG emissions of participating countries are currently covered in the market (Point Carbon, 2013). The EU ETS is a cornerstone of the European Union's policy to combat climate change and is in theory a powerful tool for cost-efficient emission reductions. The trading scheme works on a cap-and-trade principle, and emissions are reduced through lowering the cap over time. It was designed to make emissions from sectors covered by the EU ETS 21% lower in 2020 than in 2005. By setting a limit on the total number of available permits, this ensures that they have a value which is referred to as the *carbon price* or *price of allowances* (European Commission, 2013). The scheme has been divided into three different trading periods. The first, often described as the *learning by doing* phase, lasted from January 2005 to December 2007. The second period ran from January 2008 until December 2012, coinciding with the first commitment period of the Kyoto Protocol (European Commission, 2008). The third period began in January 2013 and will last until December 2020 with targets to reduce emissions by 21% compared to the implementation of the EU ETS in 2005. At present time, the price of allowances is lower than intended. The economic crisis with reducing effects on production and emissions in Europe is argued to be the main reason for the accumulation of allowances, resulting in a plunge of prices (European Commission, 2013). The accumulated surplus is listed in table 2.2 while the price developments for EUAs are illustrated in figure 2.6.

In millions	2008	2009	2010	2011	Total
Supply: Issued allowances and used international credits	2076	2105	2204	2336	8720
Demand: Reported emissions	2100	1860	1919	1886	7765
Cumulative surplus of allowances	-24	244	285	450	955

Table 2.2 - Supply/demand balance of allowances from 2008 to 2011

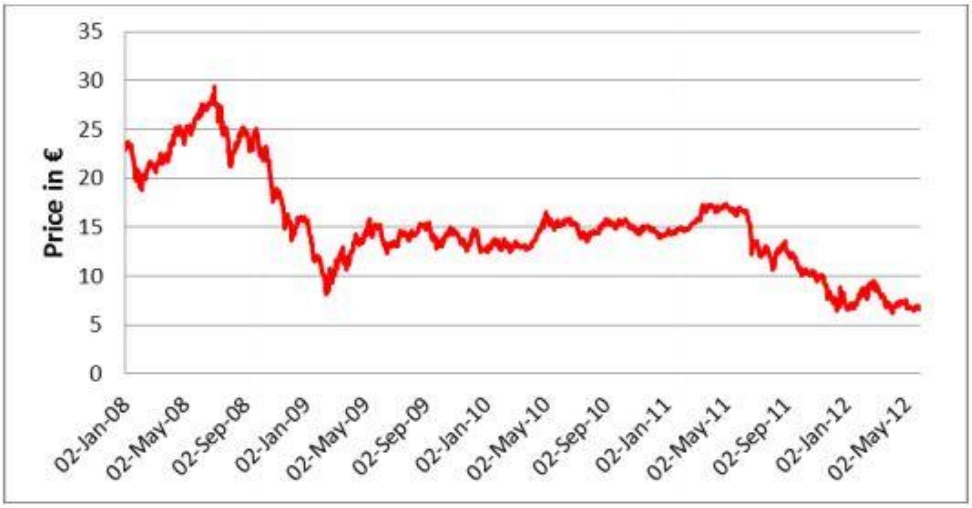

Figure 2.6 - Carbon price evolution. Source: Point Carbon, 2013

The third phase brings significant changes which are argued to have more harmonized rules. The main changes include:

- a single EU-wide cap on emissions. This will apply instead of the previous system with 27 national caps
- auctioning as a default method of allocating allowances within the EU ETS. In practice, it means that companies have to buy an increasing proportion of allowances through auctions. Over 40% of allowances will be auctioned in 2013, increasing to 100% in 2027.

This thesis will not further discuss the future price developments for allowances, but merely point out that the accumulated amount of allowances in the market might have long lasting effects. The European Commission (2012) is of the opinion that "*If not addressed, these imbalances will profoundly affect the ability of the EU ETS to meet the ETS target in future phases in a cost-effective manner, when significantly more demanding domestic emission objectives than today would have to be reached*" (European Commission, 2012). The commission is currently debating structural measures which could provide a sustainable solution to the surplus. In the short term however, the price for allowances is expected to remain at a low level. The long run price development depends on structural reforms, policies of the EU and member countries and the state of the global economy, all uncertain factors. The insight from this section is relevant for our analysis when comparing the costs per ton CO_2 reduced (abatement cost) from a PFS project on Utsira High with the price of EU ETS allowances. The analysis assumes a higher price of allowances, as stated in the Climate Cure 2020. However, the recent price development lowers the credibility for this assumption, and is an important factor in our overall discussion of the project. Before going further, some background knowledge about Norwegian climate policies are needed.

2.4 Climate policy in Norway

Norway has been subject to national environmental regulations for more than 100 years through various legislations, including the *Health law*, the *Product Control Act* and *Pollution Control Act*. As the first country in the world, Norway got its own Ministry of the Environment in 1972 (Førsund & Strøm, 2007). Leading by example has long been a central objective in Norwegian climate policies and continues to shape future commitments and targets. The Kyoto Protocol has a major impact on Norwegian climate policies, and Norway is a part of the EU ETS.

According to St. meld. no. 21 (2011-2012) sustainable development should be an overarching goal and principle in Norway and the world. The government's strategy for sustainability presented in the national budget of 2008 (St. meld. no. 1 (2007-2008), focuses on distributive justice, international solidarity, the precautionary principle, the principle that the polluter pays and joint efforts. The national targets for 2020 are described in the Climate Report from 2007 (St. meld. no. 34, 2006-2007) and confirmed in the Climate Agreement of 2012 (St. meld. no. 21, 2011-2012). The main targets are as follows:

- Norway will exceed the Kyoto commitment by 10% within the Kyoto Protocol's first commitment period.
- Norway will until 2020 be committed to reduce global GHG emissions by 30% of Norwegian emissions in 1990.
- Norway will be carbon neutral by 2050.

- As part of an ambitious global climate agreement in which other industrialized countries undertakes extensive obligations, Norway will undertake measures to achieve carbon neutrality by 2030.

In 1990, Norwegian emissions were 50 million tons CO_2 which means that national emissions must be less than 45 million tons at the end of the Protocol's first commitment period (December 31st, 2012). Final numbers for 2012 have not been released during the time of writing this thesis. However, Norwegian emissions were 53.4 million tons in 2011, indicating that the reductions are off target SSB (2013). However, NOU no. 16 (2012) states that CDM-quotas was bought to fill the gap. National emissions must be less than 35 million tons in 2020 to be on target with the international and national commitments (St. meld no. 34, 2006-2007). The Climate Report from 2007 estimates that Norwegian emissions will be 59 million tons CO_2 in 2020, and therefore calls for measures to counter this development. The goal for 2020 is to reduce Norway's GHG emissions by 15 to 17 million tons by 2020, including the effect of forests[8].

This ambitious climate policy created a need for more research, analysis and knowledge on how to meet these targets. In 2008, The Ministry of the Environment created a panel of experts, composed by representatives from Norwegian Water Resources and Energy Directorate (NVE), Norwegian Petroleum Directorate (NPD), Norwegian Public Roads Administration (NPRA), Statistics Norway (SSB) and the Climate and Pollution Agency (Klif) which led the work. The work resulted in the comprehensive report Climate Cure 2020. It considers which measures and instruments the authorities can use to implement the measures and to achieve the targets. However, it does not choose or recommend any of the measures or instruments but rather serves as an overview of alternatives. The report has become the basis of the government's assessment of climate policy. It shows that all measures with a cost up to NOK 1100 per ton CO_2 reduced must be carried out in order to achieve emission reductions of 12 million tons of CO_2 by 2020, excluding forests (Climate Cure 2020, 2010). The upper limit of reduction potential is set to 22 million tons, but this assumes future technology developments and international commitments. Consequently, there are uncertainties and broad intervals in the cost estimates. According to Climate Cure

[8] According to Klif, it has been taken as a basis that Norway will be credited with three million tons of carbon uptake in forests, and the target therefore is to reduce emissions by 12 -14 million tons by 2020.

2020 (2010), measures which are profitable for the Norwegian economy will only lead to a reduction of 3 million tons CO_2. Two different and complementary analysis methods, sector- and macro analysis, have been used to review the possibilities and effects of the measures. The report presents different menus of measures and instruments to illustrate that there are several ways to achieve the national target. However, the authorities' choice of method depends on how the different considerations are weighted through policies. It is important to emphasize the fact that these ambitious targets cannot, at present time, be considered as binding commitments. Norway is committed through binding targets in the Kyoto Protocol, but the long term national goals listed in the Climate Agreement of 2012 are not binding in the same sense. This is further discussed in part 4.4.2.

The following sections' description of Norwegian emissions is largely based on the Climate Cure 2020 report. Because of its major potential for emission reductions, the petroleum industry will be emphasized. PFS is identified as a measure with high potential for reducing emissions within the petroleum industry and on the Norwegian Continental Shelf (NCS). Norway's ambitious climate targets along with the large reduction potential with PFS rationalize why policy makers and environmental groups are pressing for action.

2.5 Sources of Norwegian emissions

The following sections describe sources and drivers for Norwegian emissions. This is done in order to gain an overview of the different sectors and their reduction potential. As described in chapter 2.4 Climate Cure 2020 (2010) has carried out an extensive analysis and evaluation of the different sectors. Information is largely based on these findings. A brief outline of total emissions from Norway will first be introduced before focusing on emission from the main sectors. The main focus will be on the petroleum industry due to its relevance for this thesis.

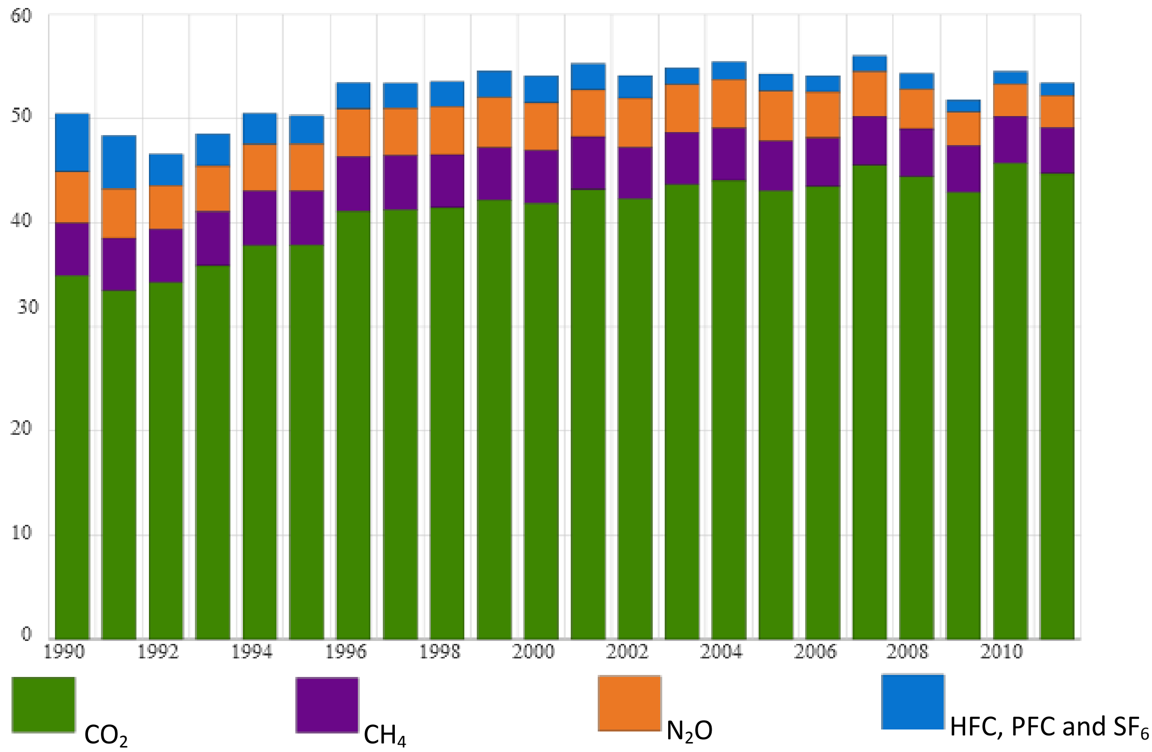

Figure 2.7 – Development in GHG emissions 1990-2011. Mill. Ton CO_2-equivalents. Source: SSB, 2013

The total GHG emissions from Norway were in 2011 estimated to be 53.4 million tons, an increase of 5.8% since 1990. According to SSB (2013), reductions in heating and combustion gave the biggest drop in the emissions. Lower emissions from the industry, oil and gas production and energy production also contributed to the drop. CO_2 is the largest contributor GHG emissions in Norway, illustrated in figure 2.7. The CO_2-emissions are mainly caused by combustion of fossil energy carriers such as coal, oil, gas, petrol and diesel in all sectors. The CO_2-emissions have increased by about 28% in the period 1990-2011, while other GHGs have been slightly reduced. CO_2-emissions amounted to 84% of the total GHG emissions in 2011, compared to 69% in 1990. The oil and gas industry was responsible for 29% of the CO_2-emissions in 2011 and were also responsible for 57% of the increase in CO_2-emissions in the period from 1990 (SSB, 2013).

GHG emissions and uptake. Mill. Ton CO_2-equivalents			
		Change in %	
	2011	Since 1990	2010-2011
Emission from Norwegian territory	**53.4**	**5.8**	**-2.1**
Oil and gas production	13.6	75.9	-1.8
Industry and mining	11.8	-38.7	-2.4
Energy supply	2.1	549.8	-10.2
Heating in other industries and households	1.6	-40	-18.2
Road traffic	10.1	29.5	-0.4
Aviation, shipping, fishing, motorized tools and more	7.3	29.4	0
Agriculture	4.5	-10.1	0.7
Other sources	2.5	13.6	0.9
Forestry[1]	-32.9	279.7	N/A
Foreign aviation and shipping	12.4	-13	-14.6
Foreign aviation	1.8	191.4	20.6
Foreign shipping	10.6	-22.2	-18.6

Table 2.1 Source: SSB, 2013
[1]This number is from 2010

2.5.1 Main emission sources

Emissions from petroleum industry, industry and road traffic amounted to two thirds of the greenhouse gas emissions in Norway both in 1990 and 2011. In 1990 the emissions from industry alone was greater than the emissions from the petroleum industry and road traffic together, but from 2007 emissions from oil and gas has alone been the greatest source of contribution to GHG emissions.

The petroleum industry contributed to 26% of the GHG emissions in 2011, versus 15% in 1990. Emissions from the petroleum industry peaked in 2007 in the same year as the petroleum industry for the first time was the largest contributor to GHG emissions in Norway. The LNG plant on Melkøya has been a major contributor to emissions from the petroleum industry, but due to lower production rates on the continental shelf[9], the emissions on the shelf has been slightly reduced since 2007. Production of natural gas nearly

[9] Especially caused by the decline in crude oil production and shut-down of facilities since 2000

doubled in the period 1990-2011, and the total production of crude oil was in 2011 at its lowest level since 1995. Emissions from the industry were nearly 40% lower in 2011 than in 1990. With a contribution of 38% of total emissions in 1990, the industry share had in 2011 decreased to 22%. Road traffic contributed to 19% of the GHG emissions in 2011, versus 15% in 1990. The emissions from agriculture have not changed much over the period, but have slightly been reduced in recent years. For a more detailed overview of the transport and industry sector and their contribution of GHG emissions, see Appendix 8.2 and 8.3.

2.5.2 Necessary abatement cost to reach national targets

Climate Cure 2020 (2010) has projected the GHG emissions from the Norwegian industry sector towards 2020 and 2030. The report estimates a slight increase in the emissions from the industry sector[10]. The report has analyzed a number of different measures that can be included before 2020 at a price of NOK 15 billion, representing a reduction potential of 5.85 million tons CO_2.

This part has pointed out some important emission drivers from the largest emission sectors in Norway. Climate Cure 2020 (2010) has evaluated 160 different abatement measures, listed in a measures database. The database contains information about emission reductions, technical and economic lifetime, CAPEX, OPEX and cost per ton CO_2 for all the analyzed measures. If all 160 abatement measures are summarized they account for 22 million ton of non-overlapping CO_2 reductions. Most measures have been analyzed for the industry and transport sector, but the abatement cost is estimated to be highest in the petroleum industry and for Carbon Capture and Storage (CCS) measures.

[10] see appendix 8.4 for figure.

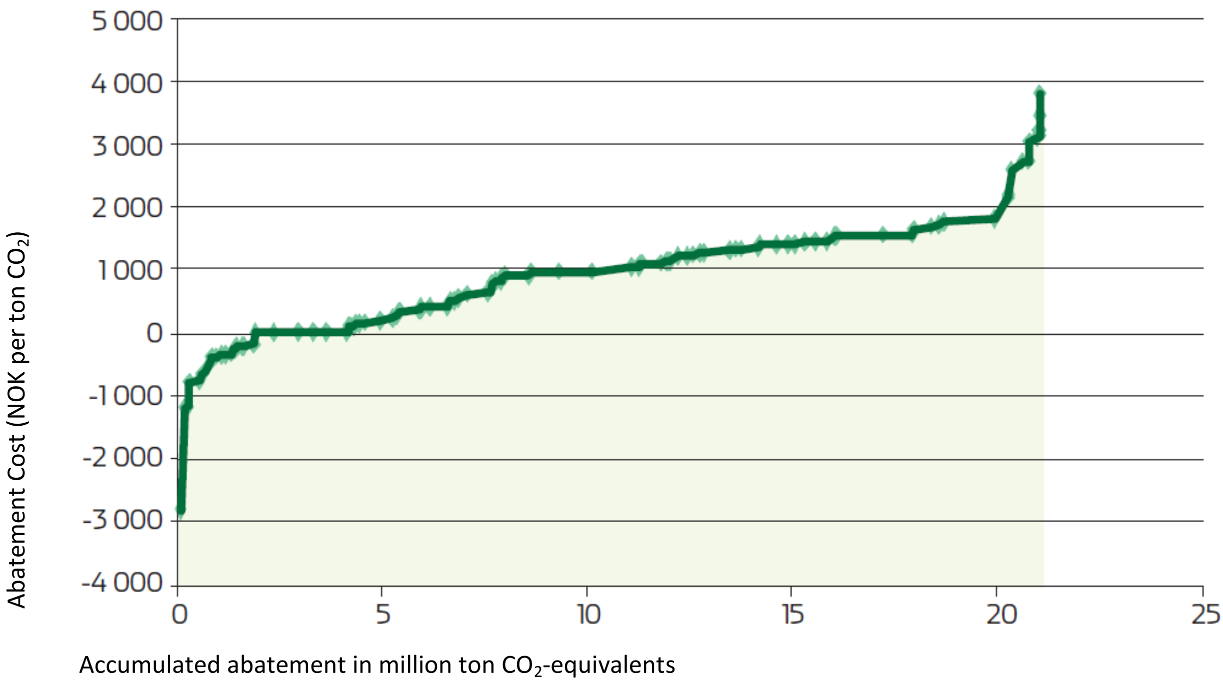

Figure 2.8 - Accumulated emission abatement from non-overlapping actions. Source: Climate Cure 2020, 2010

Figure 2.8 illustrates that some measures will return negative values. These measures are profitable for the Norwegian economy. In sectors where extensive measures already have been implemented, the reduction potential is often low and the abatement costs correspondingly high. This is the case for the petroleum industry which has been regulated with CO_2-fees and other restrictions for a long time. The remaining measures are relatively costly and limited to a few technical and large measures such as CCS and PFS. It is important to note that many of the measures are highly time dependent and will change greatly in their efficiency if they are implemented after 2020. Climate Cure 2020 (2010) states that in order to reduce 12 million tons of CO_2 within national borders by 2020, measures with an abatement cost up to NOK 1100 per ton CO_2 must be implemented. This can also be observed in figure 2.8.

The following section will give a general outline of the petroleum industry in Norway. The thesis will introduce electrification of offshore facilities with power from shore as measure with high potential to reduce national emissions.

2.6 The petroleum industry in Norway

2.6.1 Overview

The petroleum industry is the largest industry in Norway. It has played a fundamental and considerable role for the economic growth and development of the Norwegian welfare state. For over more than 40 years, production on the Norwegian Continental Shelf (NCS) has contributed with NOK 9000 billion to the Norwegian gross national product (GNP). In 2010, the sector contributed to 21% of total value creation in Norway (NPD, 2012). The petroleum industry includes all offshore installations in the North Sea, Norwegian Sea and the Barents Sea, but also onshore installations[11]. In 2011, the current 70 operating fields had an average daily production of 2 million barrels of oil (bbl.) and a yearly gas production of 100 billion standard cubic meters (Sm^3). Norway is rated as the fourteenth largest oil producer and the seventh largest oil exporter in the world. In 2010, Norway was the second largest gas exporter and the sixth largest gas producer in the world. There have been considerable investments in the Norwegian petroleum industry during the last 40 years. In 2010, they amounted to 26% of total real investments. Crude oil, natural gas and pipeline services amounted to almost half of Norway’s gross exports in 2011, and with NOK 500 billion worth of exports in 2010 it is valued 10 times larger than the export of fish (NPD, 2012).

The government owns a large part of the petroleum industry on the NCS. The industry contributed to 26% of the government revenues in 2010 through its 67% partly state-ownership of Statoil, the wholly owned companies Petoro AS and Gassled AS and through taxes and emission fees from producing companies (NPD, 2012). This income is deposited in The Government Pension Fund – Global, commonly referred to as The Oil Fund. The total value at the end of 2012 was calculated to NOK 3816 billion, making it the largest pension fund in the world, holding around 1% of global equity markets (NBIM, 2013). The Petroleum Fund was established in 1990 to counter the effects of the forthcoming decline in income, to smooth out the disruptive effects of highly fluctuating oil prices and to ensure long term effects of the revenues (NPD, 2012). Returns of the fund’s investments are gradually phased into the Norwegian economy through fiscal policies.

[11] Kollsnes, Sture, Orment Lange, Melkøya, Snøhvit, Mongstad, Kårstø. (For simplicity, these onshore installations are included in the term NCS).

Figure 2.9 illustrates the quantified size of the petroleum industry in Norway:

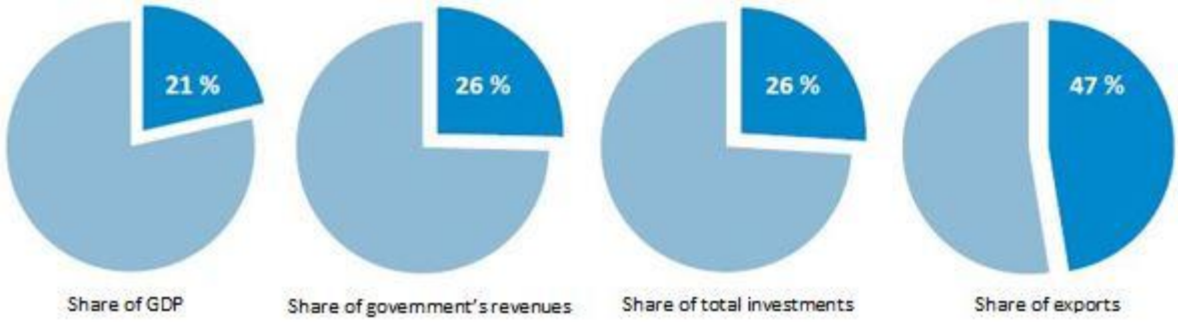

Figure 2.9 Source: NPD, 2010

According to NPD (2012), 44% of total reserves[12] are exploited. The oil production is expected to gradually decrease while the gas production is expected to increase towards 2020. Total investments are also expected to increase due to maturity of fields and costly measures to extract remaining resources. Although the infrastructure on such fields is established and the geology is well known, the remaining reserves are relatively small and challenging to extract. The oil price is determined by supply and demand. The Organization of Petroleum Exporting Countries (OPEC) is able to affect the price due to its considerable supply. Geopolitical conditions and development in financial markets also have potentially large impacts on oil price fluctuations (NPD, 2012)

The petroleum industry was in 2010 responsible for around 29% of CO_2 emissions in Norway, compared to 15% in 1990 (NPD, 2012). The main sources have traditionally been exhaust from gas turbines for operation and heating, flaring and combustion of diesel to run motors. Since the implementation of a CO_2 fee in 1991, a series of comprehensive measures has been implemented to reduce emissions. Efficiency measures and reduced flaring have contributed to 50% of the abatement. Government supported CCS at the Sleipner field has also been implemented, representing around 30% of the abatement (Climate Cure 2020, 2010). Since 2008, the petroleum industry has been a part of the EU ETS which means that oil-companies have had to buy allowances for every ton CO_2 emitted. However, in the third period of the EU ETS from 2013 to 2020, the petroleum industry will receive free allowances from the authorities (St. meld. no. 1, 2013)

[12] Discovered and undiscovered reserves.

The petroleum industry is also subject to a number of direct restrictions concerning flaring and toxic pollutants. A number of oil companies receive governmental subsidies to promote CCS technology and renewable energy such as offshore windmills. However, total emissions from the petroleum industry are expected to increase towards 2020 due to changes in the production pattern that will affect future power needs (NPD, 2012). NPD (2008) lists the main drivers for increased energy demand on the NCS:

- Measures to increase recovery from mature fields often involve increased injection of water and gas. Low pressure production from mature fields will consequently increase energy intensive processes like compression and pump work.
- Increased water production from mature fields
- Transition to a larger proportion of gas production. Gas transport is more energy intensive than oil transport.
- The industry is moving northward, resulting in greater transport distances for oil and gas. Technology development and greater depths that allow a greater proportion of the operations to happen on the sea floor. In some instances this will result in increased power needs on the plants due to pumping, artificial lifts and heating etc.

If Norway is to reach its international and national emission targets, environmental organizations and policy makers argue that heavier measures are required to further decrease emissions from the NCS (Klif, 2010). Extensive energy efficiency measures have already been implemented on the NCS and do not longer represent a large potential. CCS is argued to have high potential, but it is not considered a mature technology. Some actors in the environmental movement suggest imposing laws to phase out parts of the petroleum industry as an environmental measure. However, since the petroleum industry represents the bulk of value creation in Norway, this suggestion has limited support. The commitments to reduce emissions combined with the need to uphold production on the NCS are conflicting priorities. One way to solve the problem is to replace offshore gas turbines with power from shore (PFS). The emitting offshore gas turbines are then replaced with power from the central grid. This is called *electrification* or simply *power from shore* (PFS) (NPD, 2008).

2.6.2 Power from shore

In 1996, the government decided that PFS must be considered for all new developments on the NCS. All plans for development and operation (PDOs) of oil and gas fields must contain an analysis of the possibility of implementing PFS. This applies both to new field developments and to major reconstructions of existing facilities (OED, 2011). Other developments in proximity of the original development should also be included if appropriate. It is especially in combination with large reconstructions or development of new fields that PFS are most relevant. With smaller, existing fields it is less relevant due to short expected lifetime, large investments for the system, costs of modifying of existing infrastructure and shutdown costs (NPD, 2008). The Troll A platform was the first facility of the NCS to be electrified, and fields such as Ormen Lange, Snøhvit, Valhall, Goliat and Gjøa closely followed. The land facilities Kårstø, Kollsnes, Tjeldbergodden and Nyhamna also receive all or a part of their power from the central grid. Climate Cure 2020 (2010) estimated a reduction potential of 5.5 million tons CO_2 from electrification of the NCS in 2020, assuming newly built gas power plants with CCS technology and area electrification[13]. The investment costs range from NOK 0 to 17 billion with an abatement cost of NOK 400 to 4000 per ton CO_2 reduced.

Updated information on PFS in Climate Cure 2020 is based on the 2008 report *Power from shore to the Norwegian Shelf* by NPD, NVE and Klif. The report estimated costs and potential abatement with area electrification, and assumed partial electrification[14]. The report identified the main cost drivers as;

- Future oil, gas, carbon and power prices.
- Distance from shore
- Distance to other installations
- Expected lifetime/operating period

[13] Area electrification is done by electrifying the areas Southern, Middle and Northern North Sea, the Norwegian Sea and the Barents Sea separately, and is meant to give the largest reduction potential according to Climate Cure 2020.

[14] Partial electrification means that the turbines which produce electrical power in generators on the platform will be replaced with power supply through cable from shore. On platforms, there is also other equipment which is driven directly by the turbines without the need for electrical motors. If such equipment also is replaced with PFS, the potential for CO_2 reduction increases. This is full electrification. The report evaluated this as unrealistic due to the complexity and costs, and therefore focused on partial electrification which this thesis will refer to as electrification (NPD, 2008).

- Availability of stable and robust power grid.

The Norwegian Petroleum Directorate (NPD) receives PDOs from oil companies and consequently has a comprehensive overview of the cost estimates that are made in connection with reconstructions. The report estimated that PFS for existing facilities has a cost range of NOK 1000-4000 per ton CO_2 reduced. The estimates for planned constructions are lower, ranging from NOK 700 to NOK 3000[15]. With a current price of NOK 28.66 per ton CO_2 on allowances (Point Carbon, May 8th, 2013), it shows that PFS is relatively expensive in comparison[16].

The analysis in chapter 4 will present cost estimates for a PFS project on Utsira High. At the time this thesis was written, a decision about infrastructure design was imminent and expected to be taken in the fourth quarter of 2013, with an investment decision in 2014 (Statoil, 2012). We therefore find it highly relevant to calculate the Norwegian economy's costs of the project and compare it with the willingness to pay for emissions or the society's benefit[17] of emission reductions, reflected by the price of EU ETS allowances. By making this comparison, the cost efficiency of the project can be evaluated. Due to its extensive size and operating time, the investment decision will have a large impact on future emissions from the NCS. The PFS project will naturally reduce national emissions, but its effect on European emissions is uncertain. An introduction of the Nordic and European power markets is therefore needed in order to understand the PFS project's effect on European emissions. This introduction will thus be given before the description of method and framework in chapter 3 and the analysis in chapter 4.

2.7 Norwegian power grid and power markets

2.7.1 The Norwegian power grid

Production, transmission and consumption are the three fundamental functions of the power market. A well-functioning power system and a robust power grid is a central infrastructure in a modern society. The main function of the grid is to transfer electrical

[15] See appendix 8.5 for figure.
[16] Chapter 4.4.2 gives a throughout discussion of why the price of EU ETS allowances is an appropriate basis for comparison.
[17] Benefit and utility is used interchangeably in this thesis.

power from producers to consumers. Electricity cannot be stored in the grid, so it must be produced at the same time as it is used. There must always be an instantaneous balance between total supply and demand, which requires a robust grid with high capacity. The laws of physics tell us that the electric power fed into the grid will follow the path of least resistance, making it difficult to divide individual deliveries. It is unknown for the consumer where his electricity has been produced and the distance it has been transported through the grid. Rather, the consumer pays for its total consumption while the producer gets paid for its total production (OED, 2013).

The power grid in Norway is divided into three levels: local-, regional- and central distribution grids. The local power grid ensures final distribution of low voltage power to the consumers, mainly households, commerce and light industry. The regional grid connects the local- and central grid, and generally transfers electric power to different municipalities. The central grid has the highest voltage level, between 300 and 420 kilovolts (kV), and binds the producers and consumers together in a national grid. It also includes connections to other countries, which makes it possible to export and import power. Power distribution is subject to transmission losses, which means that a part of the energy is lost during transmission. The losses are reduced with higher voltage levels, explaining why long distance transmission in the central grid is carried out with high levels. The electric power loss in the Norwegian grid is around 10 TWh each year, which is about 8% of average yearly production (OED, 2013). To distribute the electric power between the different grids, the voltage is transformed to a lower level in transformation stations at connection points between the grids (Statnett, 2012).

Statnett SF is the transmission system operator in Norway and ensures instantaneous balance in the grid at all times. It is responsible for economically efficient operations and developments of the central grid. Furthermore, Statnett plays a key role in operation and development of transfer connections to other countries, requiring cooperation with other system operators and regulators in Europe. Nord Pool Spot organizes the physical cross-border trade of electric power through its leading market for electric power in Europe. Its majority is owned by the Nordic system operators, including operators in Estonia and Lithuania (Nordpoolspot.com, 2013).

2.7.2 Power markets

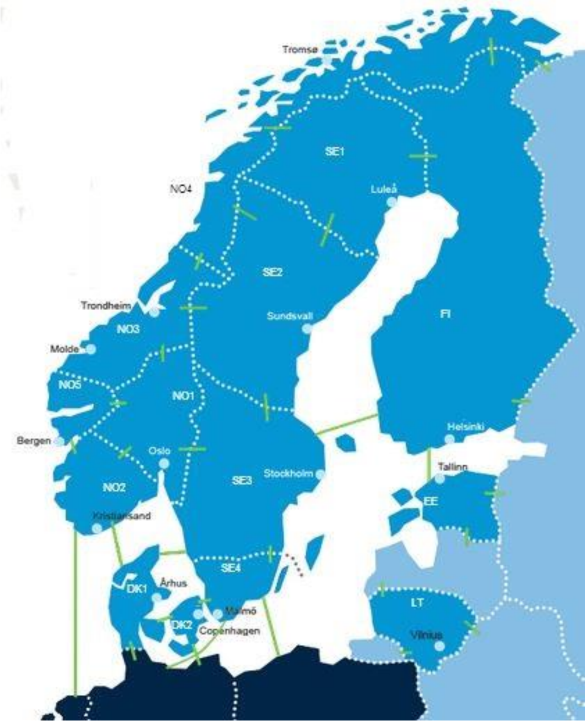

Figure 2.10 Source: Nord Pool Spot, 2013

The Nordic power market is composed of Norway, Sweden, Denmark, and Finland which in turn is integrated with the European power market through connection points to Germany, Netherlands, Estonia, Poland and Russia (Nord Pool Spot, 2013). This is illustrated in figure 2.10. Contrary to the electricity market, competition between the grid operators is prohibited as they are natural monopolies which are regulated by the respective authorities. The power market is an important tool to ensure a sustainable, economic and efficient utilization of the grid. It helps to uphold the instantaneous balance by smoothing the shifts in supply and demand. Power transfer and trade between Norway and neighboring countries have existed since the first connection point to the Swedish grid in 1960. The total transfer capacity between Norway and the markets is around 5400MW, which is about 17.5% of Norwegian production. However, a 700 MW connection point to Denmark is currently under construction and Statnett has future plans for upgrading the capacity (OED, 2013).

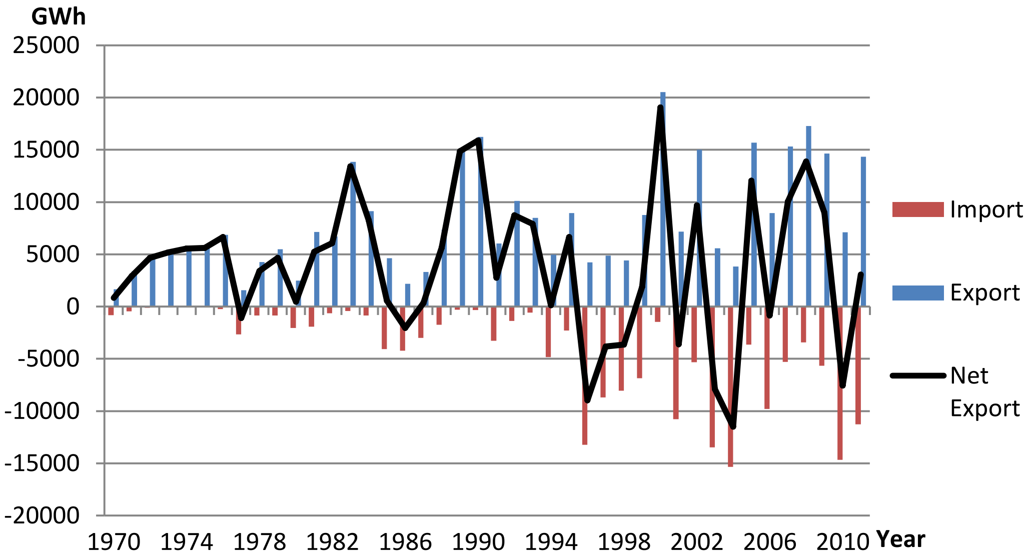

Figure 2.11 Source: SSB, 2013

Figure 2.11 illustrates Norwegian import, export and net exchange of power from 1970 to 2011. The system price for power for each hour of the following day is determined on a daily basis in the power market Nord Pool Spot. The price is a result of supply and demand in the Nordic countries, but is also affected by other power markets in Europe. Short and long term weather conditions like rain or temperature also contribute to daily, seasonal and yearly price variations. The price is also dependent on transfer conditions of the grid, in areas and countries within the Nordic region and between the Nordic countries and the rest of Europe. Tight transfer conditions and bottlenecks in the grid contribute to a heterogeneous price distribution within the market.

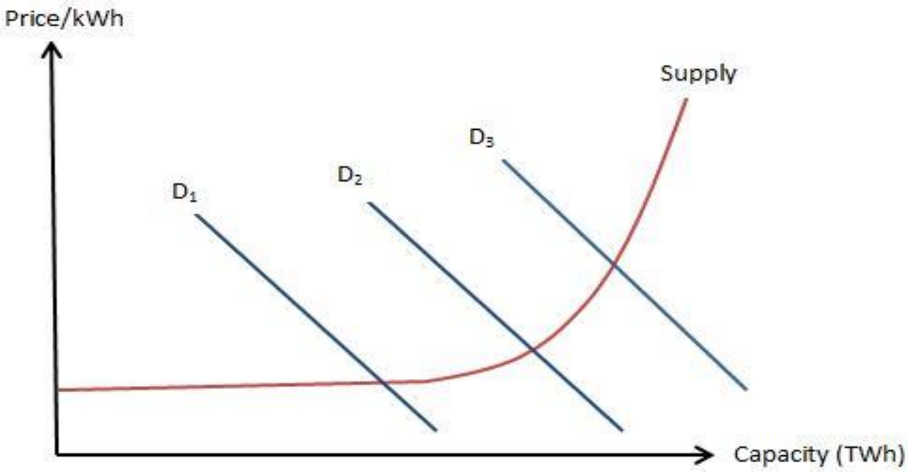

Figure 2.12 Source: Bye, Rosendahl, 2008

Figure 2.12 gives a simplified illustration of the power market on Nord Pool Spot which helps describe key elements to how the price is determined. The upward sloping supply curve shows the link between total market capacity for power production and increasing production costs. It represents how much power the producers are willing to produce at different prices. In principle, the curve shows the marginal production costs for power in the different plants, organized in ascending order from left to right. Hydro-, wind- and nuclear power have low marginal costs and can be offered at the lowest price, represented by the (more or less) horizontal left side of the supply curve in figure 2.12. Technologies like gas, oil and coal power have higher marginal costs, and are represented on the convex right side of the supply curve.

The large amount of hydropower in Norway makes the production potential highly dependent on rain, snow and inflow to the reservoirs. Variations in these factors are reflected in the seasonal and yearly power price fluctuations. The production profile in Europe is mainly dominated by thermal (51%) and nuclear (27%) power (Eurostat, 2012). Coal and gas power has relatively high marginal costs. The costs depend on the price of input factors of coal and gas, but also on the price of EU ETS allowances (Bye, Rosendahl, 2008). Since thermal power often represents the marginal production in the Nordic region and in Europe, it also affects the power price in Norway (OED, 2013).

The demand curves (D_1, D_2 and D_3) in figure 2.12 represent a decreasing function of the price, meaning that low price results in high demand and high price results in low demand. The demand curves shifts left and right, depending on factors like temperature and daily activity levels of consumers. The activity level in the economy also affects the demand for power. Times with high economic growth are often correlated with high power consumption, since power is an important input factor of products and services. Power intensive industries represent a considerable amount of the Norwegian power consumption. The international price of power intensive products therefore affects the national demand for power. High economic activity in Europe typically leads to increased prices for Norwegian industry goods, increased prices of gas, coal, EU ETS allowances and increased demand for power in Europe. The consequences in Norway are higher power consumption and power price. If the demand profile is represented by D_1, the supply of power by using hydropower with low marginal costs will cover the demand, resulting in a low power price. Hydropower is then the marginal technology. In times of high demand (D_3), the use of coal power plants is needed to cover the demand. The price is determined by the marginal costs of the last plant that are willing to produce at the current price. Coal is then the marginal technology and represents a higher marginal cost, leading to a higher price for power.

The point of this part was to illustrate that the power markets in the Nordic region and Europe are highly interrelated. A shift in the demand or supply in one country affects other countries. This fundamental knowledge is relevant when discussing the mechanisms in the power market due to electrification projects. Power production is highly correlated with emissions, explaining the shifts in European emissions due to shifts in the consumption and production profiles for power. The knowledge from this part will assist the reader to understand the intuition behind the European emission effects of a PFS project on Utsira High, described in chapter 5.

3. Method

To explain and evaluate a PFS project on Utsira High as a measure to reduce Norwegian emissions, an economic analysis for the overall economy is required. We apply the framework provided by the Norwegian Ministry of Finance. A similar approach was done in *Climate Cure 2020* (2010) and in the 2008 report *Power from shore to the Norwegian Shelf.* A description of this type of economic analysis is given before describing the framework and steps provided from the Ministry of Finance. For simplicity, the term *economic analysis* is used as analysis of public projects, investments or regulations, where it is necessary to evaluate the effects on the entire economy. The focus of the analysis is on the Norwegian economy rather than the companies' budgets.

The main focus in economic analyses is that the society's resources should be used to maximize welfare[18]. Occasionally, the majority of the work may consist of analyzing corporate economic impacts and may be compared to commercial profitability analyses. However, unlike commercial profitability analyses which generally focus on the firms' activities or profit, economic analyses focus on the use of resources to maximize societies' utility. Consequently, distributional effects such as taxes and fees are excluded. In this thesis, the economic analysis evaluates effects from a PFS project on Utsira High in terms of national costs and emissions. The abatement cost is compared with the willingness to pay for emissions in order to evaluate the cost efficiency of the project. For this purpose, a commercial profitability analysis is not applicable. The economic analysis presents information and consequences which are relevant for the decision process. This is done through systematic identification, comparison and evaluation of different consequences for the society's costs and utility. It serves as a foundation to decide if a project is economically feasible by comparing utility with cost. In principle, an economic analysis should include all the project's effects for the society's resources and utility. The project must be compared with a base scenario, e.g. the situation today. Flexible solutions and time for implementation must also be considered when evaluating the project.

The main areas where economic analyses are applied are evaluation of *public investment projects* or *government regulation changes*. An example for a public investment project is

[18] Welfare and utility is used interchangeably in this thesis.

construction of a new road, while a public regulation change could be to make the use of seat belts mandatory. These are both examples of direct measures, but analyses can also be used on indirect measures. In cases such as PFS, the regulations may be linked to large projects where it is not given that the government itself should undertake the project, but where it is desired to highlight the economic value. An economic analysis can then be applied to decide if it is profitable for the overall economy and be used by both companies and authorities in the evaluation process.

3.1 Types of economic analyses

Economic analyses are generally divided into three types. All three have in common that the measures considered in the analysis have the same objective and seek to solve the same problem. The three types can be described in short;

1. Cost-benefit analysis: All advantages and disadvantages of the measure are included. These effects must be quantified in monetary units as far as it is acceptable and gives meaningful information. Since both the cost and utility are quantified, it is possible to estimate the economic profitability and cost efficiency. Non-quantifiable effects must be described and evaluated qualitatively. These effects are included in the final evaluation of the project.

2. Cost-effectiveness analysis**:** A systematic valuation of the costs of various alternatives which focus on the same objective. The costs are given in monetary units, and the goal is to identify the lowest cost to achieve the objective. This analysis is generally used when the costs are relatively easy to identify compared to the utility, and assumes that all measures have the same effect on utility.

3. Cost-effect analysis**:** When it is not possible to value the utility in monetary units, and the degree of utility depends on the measure, a decision cannot be solely based on the costs. This analysis gives a quantitative overview of the costs and a qualitative description of the effects on utility. Like a cost-effectiveness analysis, it is not possible to value the utility in monetary units since only the costs are quantified.

This thesis performs a cost-benefit analysis since it is possible to quantify the total utility by multiplying the total abatement with the willingness to pay. As later described, the analysis uses the expected future price of EU ETS allowances to determine the willingness to pay. However, the reason for using this price will be discussed in detail in part 4.4.2. This is compared with the project's abatement cost in order to evaluate the cost efficiency.

3.2 The framework and its steps

The Norwegian Ministry of Finance's manual provides a six step framework which we apply to evaluate a PFS project on Utsira High. Figure 3.1 illustrates the steps, while a brief description is given below. The use of the manual provides us and the readers with a structured and standardized framework for the analysis, and makes it more comparable to similar work in the area. The division into steps makes it easier both to plan and conduct the analysis. It also provides a good basis for presenting the analysis, making the implementation understandable for decision makers and other readers.

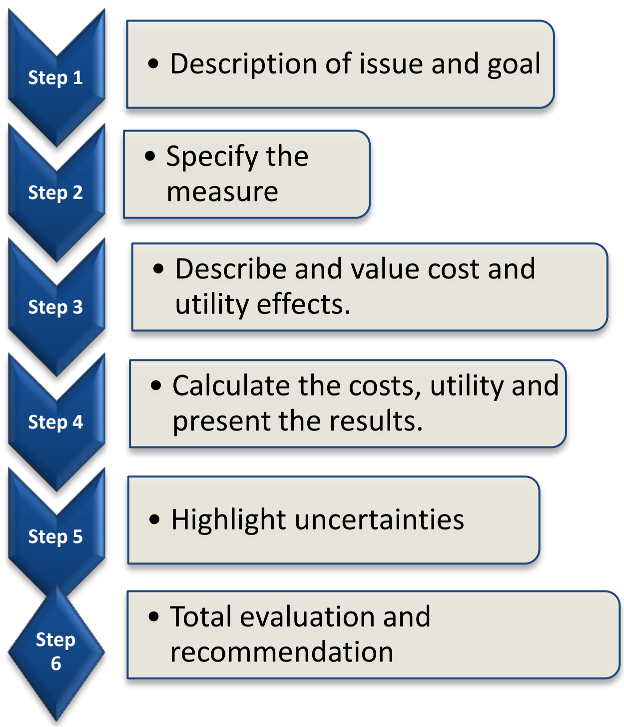

Figure 3.1 Source: DFØ, 2010

The steps provide a stylized and linear representation of the process. However, the analysis is often an iterative process rather than a linear one, where some steps are repeated several times. According to DFØ (2010), a usual process is to start at step 3, and then go back to step 1. It is also common to work with several steps at the same time, for example to value the utility- and cost effects in step 3 while calculating the economic profitability in step 4. The point is that the framework is flexible and therefore applicable to a range of different analyses. This thesis generally focuses on a straightforward approach and separates the steps in order to make the representation of the work as understandable and structured as possible. However, step 3 and 4 will be somewhat intertwined.

Step 1: Description of issue and goal,

The analysis starts with a description of the issue and outlines the current situation. What are the unmet needs that dictate and motivate the authorities to take measures in this area? What is the goal of the analysis?

Step 2: Specify the measure,

The relevant measure to reach the goal in step 1 must be identified and described. This includes a closer description of the base case and what changes the measure will cause.

Step 3: Describe and value cost and utility effects,

All assumptions and sources of the analysis must be presented. Relevant impacts for all affected actors must be described and quantified when possible and appropriate. These quantified effects should then be converted into monetary units. Some effects may be impossible to quantify, and should be described and evaluated verbally.

Step 4: Calculate the costs, utility and present the results,

First, a comparison of the NPV method and the annuity method to value the costs and utility is outlined. Second, the choice of utility factor is described, explaining the rationale behind using the expected future price of EU ETS allowances in order to quantify utility effects. Third, the main results of the analysis are presented. The costs and utility of the project are calculated based on the valued effects from step 3 by using the Net Present Value (NPV) method and an appropriate discount factor.

Step 5: Highlight uncertainties,

Most projects are subject to uncertainty. It is therefore important to highlight the main uncertainties of the PFS project. This gives a better understanding of how the project is affected by the different risk factors and may be used as a basis for measures to decrease the uncertainty. A sensitivity analysis will be conducted in order to improve the robustness of the analysis and identify factors that may change the result.

Step 6: Total evaluation and recommendation,

The last step is to give a professional evaluation of the measures and, if possible, a final recommendation.

4. Analysis

4.1 Step 1: Description of issue and goal

4.1.1 The issue:

The fundamental background for the proposed PFS project on Utsira High is Norway's commitments through the Kyoto Protocol to reduce global and national GHG emissions. It is also because of the country's objective of leading by example in climate policy, as described in chapter 2.4. Through the Climate Agreement of 2012, Norway has non-binding goals to reduce a large share of its emissions within national borders. As explained in chapter 2.6.1, the petroleum industry is responsible for 26% of Norwegian GHG emissions, representing a large reduction potential. Johan Sverdrup alone is estimated to contain 1.887-2.516 billion barrels of oil[19] (Petoro, 2013), which is very large on a national scale, making it the third biggest field after Statfjord (3.6 billion bbl.) and Ekofisk (3.5 billion bbl.). Consequently, the associated emissions from the development and extensive operations phase are considerable, meaning that the investment decision will have a large impact on national emissions. Note that the recent discovery of Johan Sverdrup in 2010 and 2011 means that future emissions from this area are not included in the Climate Cure 2020 report. The discovery of the oil and gas fields on Utsira High means increased revenue and national welfare, but it also challenges Norway's ambitious climate policies and commitments.

It is required that all assessment reports for development and operation of oil and gas fields on the NCS must consider and analyze the possibility of PFS (mentioned in chapter 2.6.2). In other words, an assessment report for a PFS project on Utsira High is made as a result of government policies rather than company decisions. Note that PFS projects *could* be profitable both for the company and the country as a whole, but by imposing mandatory studies this is an example of an indirect political measure. A PFS project has the potential to obtain the wealth from petroleum extraction without increasing national emissions. However, most of these projects are expected to be very costly (Climate Cure 2020, 2010). This analysis estimates national emission reductions from a PFS project on Utsira High and its accompanying abatement cost per ton CO_2. A recommendation will be made by evaluating the project's cost efficiency. This is done by comparing the abatement cost per ton CO_2 with

[19] By including natural gas, the estimate is up to 3.5 billion barrels of oil equivalents (TU, 2013)

the willingness to pay for emissions. As later described, the price of EU ETS allowances is used to quantify the willingness to pay.

4.1.2 Summary of the base case:

Offshore facilities mainly use gas turbines for power generation, representing the bulk of emissions on the NCS. The main companies with license to operate on Utsira High, Statoil, Lundin and Det Norske, have clearly voiced that gas turbines will be used on Utsira High if PFS is not implemented (Statoil, Lundin, Det Norske, 2011). The use of gas turbines is therefore considered as the *base case* for the project. The consequence is an increase of Norwegian emissions[20]. In the base case, total emissions depend on the facilities' power demand and combustion of natural gas. It is also important to acknowledge the use of opportunity costs when comparing the electrification project to the base case. The most prominent example is savings in capital expenditure (CAPEX) due to reduced investments in gas turbines. The expected effects of an electrification project must always be compared with the base case.

4.1.3 The goal:

The primary goal of the PFS project is to reduce GHG emissions. Obviously the implementation of PFS will reduce national emissions. In this analysis, an evaluation will not be made on *whether* the project will lead to abatement, but rather on the *size* of the abatement and the *Net Present Value (NPV)* of the project. The discounted quantity of reduced emissions and the NPV of costs make it possible to calculate the abatement cost of the project. The abatement cost is compared with the willingness to pay in order to evaluate the cost efficiency of the project. As later discussed, the final conclusion will always depend on the goal of the analysis; for companies, the goal may be to determine the profitability of the project. For the environmental organizations, the goal may be to calculate if the project will have an abatement cost less than NOK 1100, the necessary abatement cost in order to reduce national CO_2 emissions by 12 million tons within Norwegian borders by 2020. However, this analysis seeks to highlight whether the project is profitable for the society as a whole, based on binding commitments and targets through the Kyoto Protocol. In other words, the goal for this analysis becomes:

[20] This amount is calculated in step 3 and 4.

Is a PFS project on Utsira High a cost efficient climate measure to reduce Norwegian emissions?

4.2 Step 2: Specify the measure

This step identifies and describes all relevant aspects to include in order to fulfill the goal of this analysis. If the goal of this analysis had been to find the optimal solution to reduce emissions from Utsira High, alternatives such as wind power, CCS and energy efficiency measures should have been included. However, in the screening process these alternatives would have been dropped, primarily because of budgetary and technical constraints and with respect to time. With CCS or wind power, the system would not be ready before the operational phase of the offshore facilities. It would also have been unrealistic to consider these alternatives since they are not considered by policy makers or companies, and deemed by Climate Cure 2020 (2010) to have extremely high abatement costs. As mentioned in chapter 2.6.1, energy efficiency measures on offshore installations have been implemented to a great extent. Consequently, the cost of further improvements is very high and strongly depends on technology development. For our purpose, electrification is left as the only viable alternative.

In order to describe and quantify the cost-benefit effects and evaluate the cost efficiency of electrification in step 4, the measure must be specified based on practical implementation. The following presentation of practical implementation is largely based on information from NPD. However, we have also made our own assumptions where applicable.

4.2.1 General outline and summary of the project:

Electrification of the offshore facilities means that power from traditional gas turbines is replaced by power from shore through subsea cables. A connection point with transformer is connected to the Norwegian central grid and distributed to an onshore rectifier building. Power is transported through two 250MW HVDC subsea cables to an offshore hub (receiving platform) with transformer on Utsira High. From the hub, the power is transformed and further distributed to receiving stations placed on installations at Johan Sverdrup, Edvard Grieg, Ivar Aasen and Dagny through AC subsea cables. Some of the facilities require alternative sources for heating (add energy, 2012). In the base case, this heating requirement is covered through Waste Heat Recovery Units (WHRU) which recycles waste-heat from gas turbines to be used for heating. Statoil (2012) states that if the PFS system is implemented, these units are replaced with gas fired boilers which use natural gas to cover the heating requirement. The boilers have 90% efficiency (NVE, 2011) and do not represent a major source of emissions. According to NPD (2008), this is referred to as partial electrification, as some of the facilities' power demand is still covered through combustion of natural gas. According to NPD (2008), factors like technical challenges, separate requirements for individual facilities and higher costs are likely to be of larger significance with full electrification. Whenever this thesis refers to electrification or PFS, it refers to partial electrification. The following sections give a comprehensive description of the practical issues of project.

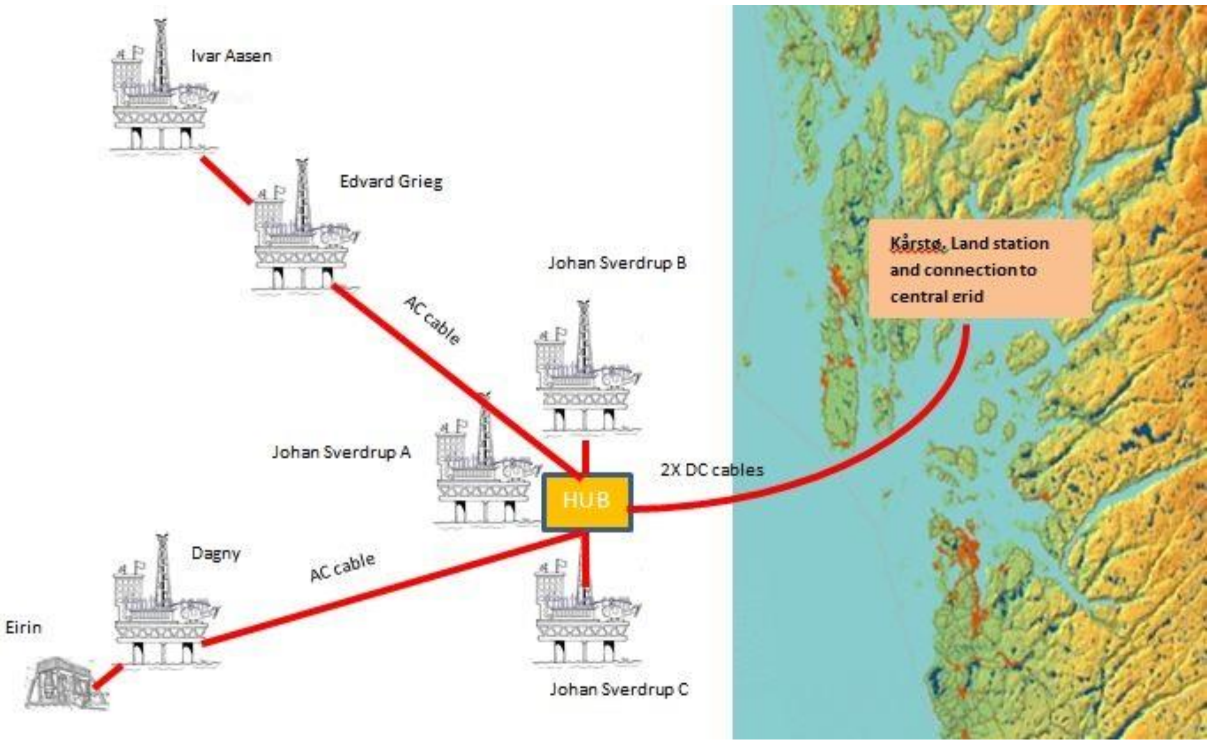

Figure 4.1 - System overview

4.2.2 Base case and time constraints

In order to estimate the effects of a PFS project, a closer look at the base case is required. PFS is compared with a reference case with local power supply from offshore gas turbines in order to identify the relevant factors to include in the analysis. All factors which are *changed* must be included and can indicate costs or savings. Time constraints must also be outlined to be applied as deadlines for an operational PFS system[21]. The following information is derived from the respective companies' plans for development and operation (PDOs) and impact assessments. Due to the lack of assessment report for Johan Sverdrup, own assumptions are supplemented with preliminary reports from Statoil (2012) and add energy (2012). The heating requirements on all offshore facilities are uncertain. Estimates from add energy (2012) and Statoil (2012) are therefore applied to determine this factor. For gas turbines, the use of LM2500+ from General Electric (GE) is assumed. This is a basic model and the most common gas turbine on the NCS (Statoil, Lundin & Det Norske 2011). The impact assessments also indicate the use of this gas turbine (Statoil, 2012). Final choice of gas turbines will affect capital expenditure (CAPEX) to a large degree, so considerable research has been done to confirm this assumption. Power demand and time estimates for the offshore installations are briefly described in the following sections[22].

Dagny and Eirin

Based on the assessment report by Statoil (2012), the base case includes two GE LM2500+ gas turbines for local power generation. All electric equipment uses power from this source, including equipment for gas compression. Furthermore, the marginal demand for heating on the platform does not require a Waste Heat Recovery Unit (WHRU)[23]. Power from Dagny is transferred to Eirin, which is an electrified subsea facility with no need for heating. Production start for Dagny and Eirin is expected by the end of 2016. Both facilities are expected to be shut down in 2035.

Edvard Grieg and Ivar Aasen

Edvard Grieg will supply Ivar Aasen with power through AC cables, meaning that Ivar Aasen is planned to be electrified in the base case. The power requirement is covered by two GE LM2500+ gas turbines on Edvard Grieg. Production start on Edvard Grieg is expected in the fourth quarter of 2015 and heating requirement is covered through one WHRU. Production start on Ivar Aasen is expected by the end of 2016 and heating requirement is expected to be negligible. Expected shutdown of Edvard Grieg and Ivar Aasen is at the end of 2030 and 2028 respectively.

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[21] This analysis does not assume expansion or shortening of the operational phase by implementing an electrification project, however it is included in the sensitivity analysis.
[22] For details concerning time estimates collected from assessment reports, see Appendix 8.6.
[23] WHRU's recycles waste-heat from gas turbines to be used for heating.

Johan Sverdrup

Due to the size of Johan Sverdrup, three production facilities are expected. These facilities are assumed identical with similar power demand. Two GE LM2500+ gas turbines and one WHRU are required on each facility. An internal cable system is also developed in order to enable field internal power pooling, increasing the efficiency and flexibility of power production. According to Statoil (2012), *first oil*[24] is expected at the end of 2018. The size of the field requires a phased development, making the production startup for all facilities on Johan Sverdrup highly uncertain. Therefore, this analysis assumes production start on the first facility at the end of 2018. After 2018, the next two facilities are expected to produce within two and four years respectively. Statoil (2012) estimates shutdown of the field in 2060.

Deadlines for expected production start on the facilities are illustrated in figure 4.4 together with time estimates for the PFS project. This gives an overview over the practical implementation of the electrification project with respect to time constraints given in the assessment reports. For more detailed information of the different time constraints for the individual facilities, see Appendix 8.6.

A simple overview of main *changes* will also be presented at the end of this step. These include changes in capital expenditure (CAPEX), variable operational expenditure (OPEX) and fixed OPEX. Together, they form the basis for our calculations.

4.2.3 Connection to the grid and evaluation of possible alternatives

When evaluating possible alternatives for onshore grid connections, important factors must be considered. NPD (2008) has identified the main factors to be:

- Physical distance
- Capacity and robustness of the local and regional power grid
- Conditions on the sea bed from the designated connection point to the offshore installation
- Easy connection to the grid by applying industrial clusters or other suitable areas which has the potential for synergy effects.

[24] The term *first oil* is used to describe the production start of an oil and gas field.

By applying these constraints, Statoil (2012) has listed the following alternatives. An evaluation of the different alternatives is made before determining the most suitable location.

- Feda
- Lista
- Kårstø
- Blåfalli
- Kvilldal
- Stavanger/Risavika

Prior to the discovery of Johan Sverdrup, the earliest studies of PFS to Utsira High concluded that the onshore system requirement was 150MW with high regularity and satisfactory location for the onshore converter and transformer station. According to Statoil, Lundin and Det Norske (2011), Statnett informed in a letter dated December 15th, 2010 that Kårstø was a preferred location for connection to the national grid for this project. Furthermore, Statoil informed that *"Onshore connection in existing switchgear station, cable routing and location of required buildings/equipment are verified to be technically feasible at Kårstø. The grid is considered to be strong, reliable and have excess capacity. The location of the onshore converter and transformer station is considered to be excellent. The main routing of the cable from Kårstø Switchgear station to converter and transformer station (two alternatives) further to connection to offshore subsea cable has been performed based on existing data and field surveys"* (Statoil, Lundin & Det Norske, 2011, p. 11). The locations Feda and Lista were also evaluated, but the distance to Utsira high was considered too great, thereby increasing the costs for subsea cables. Feda and Lista are therefore excluded from our analysis.

Including Johan Sverdrup, recent reports from Statoil and NPD suggest a system capacity requirement of 250MW for Utsira high. If Kårstø is to remain the favored location, the region's grid capacity must be analyzed for this scenario. Figure 4.2 shows how the transmission capacity is rated when considering today's consumption profile and including already planned reinforcements to the grid. Haugalandet is relevant for Kårstø, and as illustrated the area has a robust transmission capacity. Based on surveys and evaluations in cooperation with Statnett, NPD concludes that a connection point on Kårstø with a capacity up to 300MW will not require a reinforcement of the power grid on Haugalandet.

Figure 4.2 Source: NPD, 2012

However, there has been a conflict of interests concerning a possible expansion of an aluminum plant on Karmøy. It has been argued that a PFS system with connection point at Kårstø would compromise the aluminum plant expansion due to tighter constraints in the region's power grid (TU, 2012). On this basis, Statnett recommended to extend the cables further inland to connection points at Blåfalli or Kvilldal where the grid capacity is more suitable. From the companies' perspective, these are unfavorable locations for onshore connection since they significantly increase the capital investments for DC cables. An expansion of the aluminum plant at Karmøy would increase the power demand by 415MW, meaning that this expansion alone would require a reinforcement of the grid (TU, 2012). The grid capacity must be increased if the aluminum plant expands, whether the PFS project is implemented or not. For this reason, an expansion of the aluminum plant at Karmøy becomes irrelevant for the evaluation process. In any case, the grid capacity will be sufficient for the PFS project.

Currently, Risavika does not have the necessary grid capacity for a connection point. Statnett states that a planned expansion of a 300kV power line in the region will be sufficient to satisfy the conditions. However, this is a lengthy process which will shift the timetable for the electrification project. Consequently, it will increase the risk that the system is not operational in due time for the planned start-up for producing facilities on the Johan Sverdrup field. Laying and trenching the cables in densely populated areas also might result in costly challenges.

The evaluation of possible connection points to the grid concludes that Kårstø is the most realistic option, and the analysis will be based on this decision. Detailed studies in 2012 on the sea bed topography between Haugalandet and Utsira High have so far brought promising results. However, further studies will be conducted in 2013 to give a final conclusion (Statoil, 2012).

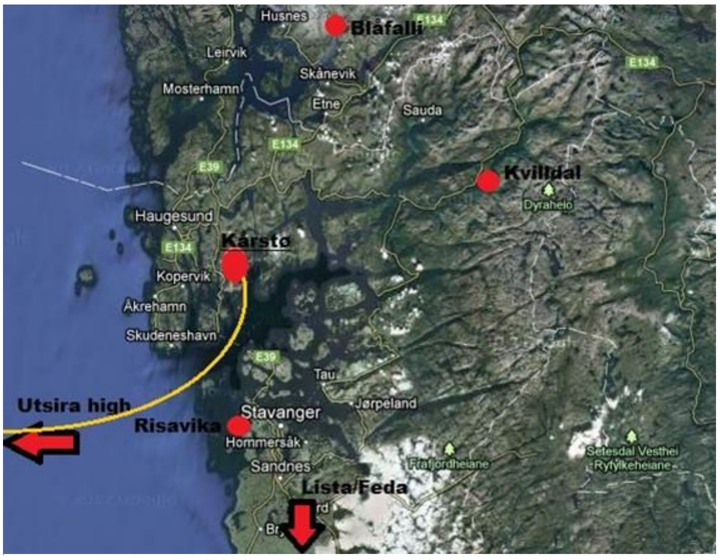

Figure 4.3. Overview of locations

4.2.4 Power distribution to offshore hub and producing facilities on Utsira High

According to NPD (2008), add energy (2012) and Statoil, Lundin, Det Norske (2011), power distribution from the mainland rectifier building to the offshore hub will be done through two subsea High Voltage Direct Current (HVDC) cables. An alternative is to apply cables with Alternating Current (AC). However, DC cables are more suitable for large transmission distances due to the large transmission loss in AC cables. The high power demand[25] on Utsira High suggests that the cables will require a transfer capacity of 250MW[26].

An offshore hub is required to transform the HVDC into AC which will be distributed to the producing facilities on Utsira High through AC cables. As Johan Sverdrup is located closest to shore, has the longest expected lifetime and will have the largest energy demand over time, the hub is likely to be located in proximity with one of the production facilities on this field.

[25] As estimated in section 4.3.6
[26] This figure is uncertain due to the high uncertainty on future power demand from Johan Sverdrup. A conclusion for total power demand is expected to in the fourth quarter of 2013.

It can be done by constructing a separate platform for the hub with bridge connection to a producing facility or by merging the two facilities on one platform. The final solution is uncertain and beyond the scope of this analysis. However, most recent reports from Statoil (2012) and cost estimates received from NPD indicate that separate constructions with bridge connection is the most viable option. This is the only alternative for which we have received cost estimates, and will therefore be the case for the analysis.

From the Hub, power is distributed to all producing facilities on Utsira High through AC cables. AC cables have been planned between the following installations:

1. Edvard Grieg and Ivar Aasen
2. Dagny and Eirin
3. Johan Sverdrup A, B and C

These cables will therefore be irrelevant for the cost estimates. However, the base case does not include AC cables between the three above mentioned areas on Utsira High. AC distribution from the hub to the respective areas must therefore be included. It is unreasonable to assume that the PFS system will be operational before the production start on Edvard Grieg and Ivar Aasen in 2015 and 2016 respectively. As described in the impact assessment of Lundin (2011) and Det Norske (2012), the facilities will therefore be equipped with the originally planned gas turbines. The turbines will be set on standby when the PFS system is operational and serve as a backup source if needed. The same scenario applies for Dagny and Eirin. But with PFS, only one gas turbine will be implemented instead of two. This turbine will also be set on standby when the PFS system becomes operational. Preliminary plans from Statoil (2012) and research conducted by add energy (2012) concludes that the PFS system will be operational by the startup of the first producing facility on Johan Sverdrup. We also apply this assumption. If the system becomes operational after this time, facilities on Johan Sverdrup will require local power generation with gas turbines. This will significantly increase the costs of the electrification by avoiding savings from the opportunity cost of buying gas turbines.

All facilities will require a receiving facility which will replace the planned gas turbines. According to Statoil (2012), these receiving facilities have similar weight and dimensions as

LM2500+ gas turbines. On facilities with both gas turbines and receiving facilities, the additional space requirement is likely to increase CAPEX. However, these cost effects are highly uncertain and will not be included in the analysis. Uncertainties of CAPEX will be captured in the sensitivity analysis in chapter 4.5.

Finally, the time estimates and main milestones for the PFS project as presented from Statoil (2012) are as follows:

- **2013, fourth quarter:** Choice and decision of design.
- **2014, third quarter:** Establishment of contracts with long delivery periods.
- **2014, fourth quarter**: Final investment decision.
- **2017, second quarter:** Installation of onshore and subsea cables.
- **2017, third quarter:** Offshore constriction of hub and transformers.
- **2018, first quarter:** System operational for power from shore.

An overview of time estimates and deadlines are illustrated in figure 4.4. Table 4.1 lists the main changes by implementing PFS.

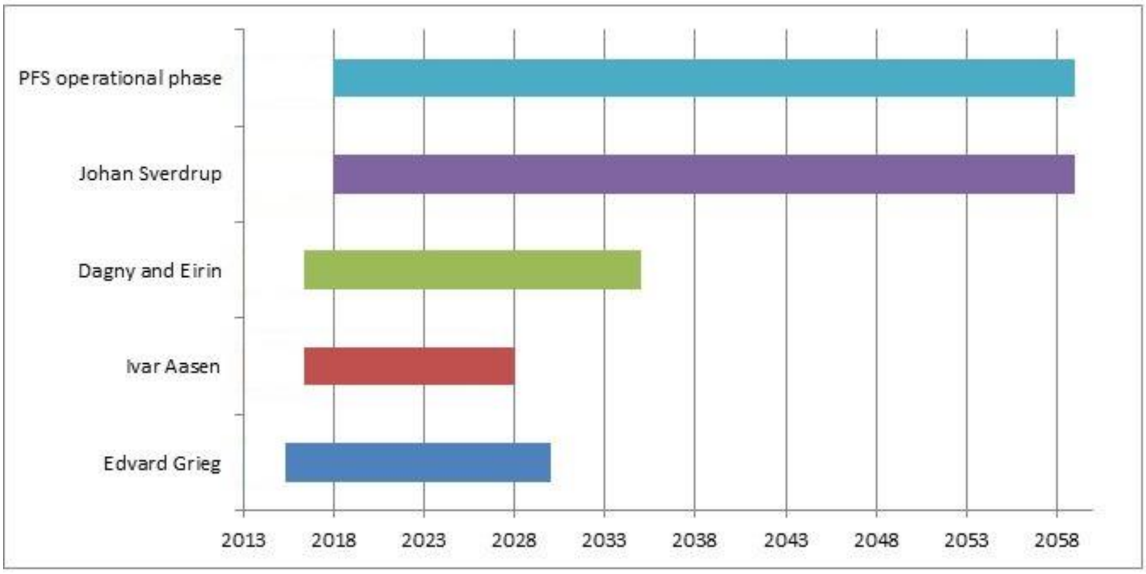

Figure 4.4 Illustration of time horizon of the PFS system and operational phase of offshore facilities

Changes compared to base case		
Factor	**Change**	**Costs or savings**
CAPEX	Investment in equipment for PFS system, including transformers, land station, hub, gas fired boilers and all additional DC/AC cables.	Costs
	Reduced amount of gas turbines and WHRUs.	Savings
Fixed OPEX	System operating costs on land station, hub and offshore facilities.	Costs
	Reduced operating cost on gas turbines.	Savings
Variable OPEX	Offshore installations must buy electricity from mainland grid.	Costs
	Increased export of natural gas.	Savings

Table 4.1

4.3 Step 3: Describe and value cost and utility effects

The following sections take a closer look at the different assumptions that apply for the analysis. Considerations have been made for every assumption in order to perform as accurate calculations as possible and derive a result close to the actual abatement cost for the project. Aside from own assumptions, we have used reputable and trustworthy sources. All prices are index-adjusted to 2013 prices. At the end of this part, attention will be given to the non-quantified effects of the project which cannot be presented in monetary units.

The assumptions are presented in table 4.2 by sorting them into respective groups that were applied in the calculations:

Economic parameters	CAPEX	OPEX
- Natural gas - Electricity - Emissions - Energy Demand	- Investment costs - Savings	- Fixed opex - Variable opex

Table 4.2

4.3.1 Natural Gas

Natural Gas			
Net price natural gas	2.28	NOK/Sm^3	Petoro (2012)
NGL price	4080	NOK/ton	Statoil (2012)
Calorific value natural gas EG	10.76	kWh/Sm^3	NVE(2004), BNG(2013)
Cost per gas turbine LM2500	450	Mill. NOK	Statoil, Lundin, Det Norske (2011)
Gas turbine efficiency	35%		Statoil (2005)
Gas-fired boilers	90%		NVE (2011)
NGL per mill Sm^3 rich gas	289	ton	Statoil (2012)
Dry gas per mill Sm^3 rich gas	0.83	Mill. Sm^3	Statoil (2012)

Table 4.3

The net price for natural gas is obtained from Petoro (2012) and for simplicity held constant for all years. For the NGL price, we have in compliance with recommendations from Statoil (2012) calculated a 2.5% yearly growth in the price between 2020 and 2030. To easier compare the calorific value of natural gas with energy demand on Utsira High, kilo joules per Sm^3 is converted into kWh[27]. Statoil (2005) reports average efficiency of GE LM2500+ gas turbines to 35%[28]. NVE (2011) reports an average efficiency of 90% from offshore gas-fired boilers.

4.3.2 Electricity

Electricity			
Electricity price 2012	0.45	NOK/kWh	Climate Cure 2020 (2010)
Electricity price 2015	0.45	NOK/kWh	Climate Cure 2020 (2010)
Electricity price 2020	0.58	NOK/kWh	Climate Cure 2020 (2010)
Electricity price 2030	0.79	NOK/kWh	Climate Cure 2020 (2010)
Transfer loss subsea cables	7.50%		add energy (2012)

Table 4.4

Assumptions on future electricity prices are based on estimated prices from Climate Cure 2020 (2010). A linear price increase between the time periods has been assumed and

[27] One watt = 1 J/S => 43600 KJ/Sm^3 = $43600*2.77778*10^{-4}$ = 12.11 kWh/Sm^3

[28] Efficiency of gas turbines are related to the percentage of energy left after combustion of gas, transformation to kinetic energy and to electric power. Efficiency of gas fired boilers is higher mainly due to the fact that useable energy is in terms of heat. Loss by transforming kinetic energy to electric power is avoided.

accounted for in the calculations. Add energy (2012) has estimated a transmission loss of 7.5% in subsea cables. This percentage is similar to what was used in *Power from shore to the Norwegian Shelf* (2008) and what Statnett uses in own calculations. The transmission loss of 7.5% is accounted for when calculating the total amount of electricity required from the central grid[29].

4.3.3 Emissions

Emissions			
CO_2 emission factor	2.124	Kg/Sm^3	Klif (2011)
CO_2 emissions gas turbines	564	Ton/GWh	Calculated[30]
CO_2 emissions gas-fired boilers	219	Ton/GWh	Calculated

Table 4.5

The emissions and the emission factors are important for the calculations in order to calculate total emissions from the base case scenario. The accuracy of these numbers therefore has a large impact on the final abatement cost. The difference between emissions from gas turbines and the gas-fired boilers are mainly due to the different efficiency rates.

4.3.4 Emission related costs

Emission related costs			
CO_2 allowance (EUA) 2013	28.66	NOK/ton	Point Carbon (2013)
CO_2 allowance (EUA) 2020	298	NOK/ton	Climate Cure 2020 (2010)
CO_2allowance (EUA) 2030 and beyond	744.75	NOK/ton	Climate Cure 2020 (2010)

Table 4.6

In May 8th, 2013, the price for EU allowances stood at NOK 28.66. Assumptions for future price of allowances are derived from Climate Cure 2020 (2010). The report expects a heavy price increase towards 2020 and 2030. Comparing with the current price, this assumption can be argued to be unrealistic. The estimations from Climate Cure (2010) are made by Point Carbon. In the absence of other realistic projections of future prices of allowances, we are required to use these estimations which, in our view, represent the maximum prices over the time period. Due to the relevance of this critical factor for the final result, this will be further discussed in step 4. For all variable prices in the analysis, a yearly geometrical growth

---

[29] Companies must buy (1 / (1-0.075))-1 = 8.1% more electricity to account for the transmission loss.
[30] CO_2-emission factor/(Calorific value natural gas)*Gas turbine efficiency))*1000 = (2.124/(10.76*0.35))*1000 =564 ton/GWh

rate is assumed. E.g. in the case of allowances, the growth rate of this price becomes 39.7% each year from 2013 to 2020 and 9.6% from 2020 to 2030.

4.3.5 Other factors

Heating requirement per facility has been set to 10 MW, which leads to a yearly requirement of around 87.6 GWh per facility. Only facilities on Edvard Grieg and Johan Sverdrup have this heating requirement, totaling 350.4 GWh/year. As mentioned, the heating requirement is covered through gas fired boilers. Although the heating requirement is relatively small compared to the total power demand, it still requires modifications of the calculations. Remember from section 4.2.4 that the total power requirement for individual facilities is obtained from the companies' assessment reports and PDO's. Power for heating is included in these numbers and must be deducted in order to calculate the correct amount of power to be supplied from shore to find the yearly demand[31] from the central grid.

Contingency Cost is set to 25% and included in our calculations in accordance with numbers supplied by NPD, add energy (2012) and Statoil (2012).

As with any investment project**,** assumptions about the *discount rate* must be carefully considered due to its impact on NPV. It is generally recommended to consult with experts to calculate the correct discount rate. According to NPD (2008), the norm is to use a 7% discount rate on petroleum investments. Infrastructure in the power market often uses a discount rate between 5% and 5.5%. Environmental investments do normally operate with a lower rate. The Ministry of Finance uses 6% for high risk, 4% for moderate risk and 2% for low risk projects. The general recommendation from the agencies and departments behind the *Power from Shore* report (NPD, 2008) is to apply a 5% discount rate for electrification projects (2008). This is one of the major cost drivers in the PFS-project and will be included in the sensitivity analysis. Thus, we do not find it necessary to calculate the project specific Weighted Average Cost of Capital (WACC), but rather analyze the effect and consequences of changes in the discount rate. In accordance with the given recommendation from NPD, a 5% discount rate is applied in our calculations.

[31] Yearly demand = Sum of total yearly power demand derived from impact assessments – (Total heating requirement in GWh*Transmission loss)

Gas turbines overview				
	Originally planned	With electrification	Turbines on standby after electrification	*Source*
# Johan Sverdrup	6	0	-	add energy (2012)
# Dagny	2	1	1	Statoil (2012)
# Edvard Grieg and Ivar Aasen	2	2	2	Lundin(2011)

Table 4.7

The number of gas turbines has been reported from the different operator's impact assessments. The turbines are important factors for the analysis when deriving the amount of emissions and electricity produced on the installations. The reduction of gas turbines will represent savings of the PFS project.

4.3.6 Power Demand

Statoil, Lundin and Det Norske have estimated their future energy demand in their impact assessments and PDO's. These reports give detailed information on the projects from the planning phase to the final dismantling and shut down of production. They estimate the production period, list the number of wells that will be drilled, reservoir pressure and what equipment and tools that will be used to extract the petroleum. By using the different impact assessments and PDOs, the analysis uses realistic assumptions for future energy demand on Edvard Grieg, Ivar Aasen, Dagny and Eirin

The power consumption profile on Johan Sverdrup is unknown, but will account for the largest share due to its size and lifetime. As mentioned, an impact assessment from Statoil will become public in the fourth quarter of 2013, giving realistic estimates. We have been in contact with NPD in order to obtain the most recent estimates for Johan Sverdrup.

NPD provided rough estimates for Johan Sverdrup by referring to a preliminary status report from Statoil. Our contact at NPD wrote the following on the energy demand of Johan Sverdrup (translated from Norwegian) "*The problem is that the design of facilities for Johan Sverdrup has not been decided– i.e. the license has not decided on how they wish to construct and develop the field. The only thing that is clear is that there will be a phased development of the field, where they gradually construct more over time. To estimate energy* *demand so far out in time is normally difficult, and the previous facts do not make it easier. A drainage strategy has not yet been decided and it is also hard to schedule when there will be demand for pressure support or water injection, especially before reservoir geological assessment has been conducted. Later in the field life there will be conducted other IOR-measures (increased recovery), which can be very energy demanding,* Inger Ubbe (NPD, 2013).

On recommendation from NPD, the available information from the preliminary report is used to estimate the total energy demand for Johan Sverdrup. The report lists estimated energy demand in certain years with 2-10 year intervals. This analysis assumes linear growth and reduction in the intervals to estimate the complete energy demand for the field over its lifetime and its yearly variations. Total energy demand of Utsira high is illustrated in figure 4.5 below. It shows the combined demand from all installations and serves as an overview of total energy demand, excluding heating, independent of source.

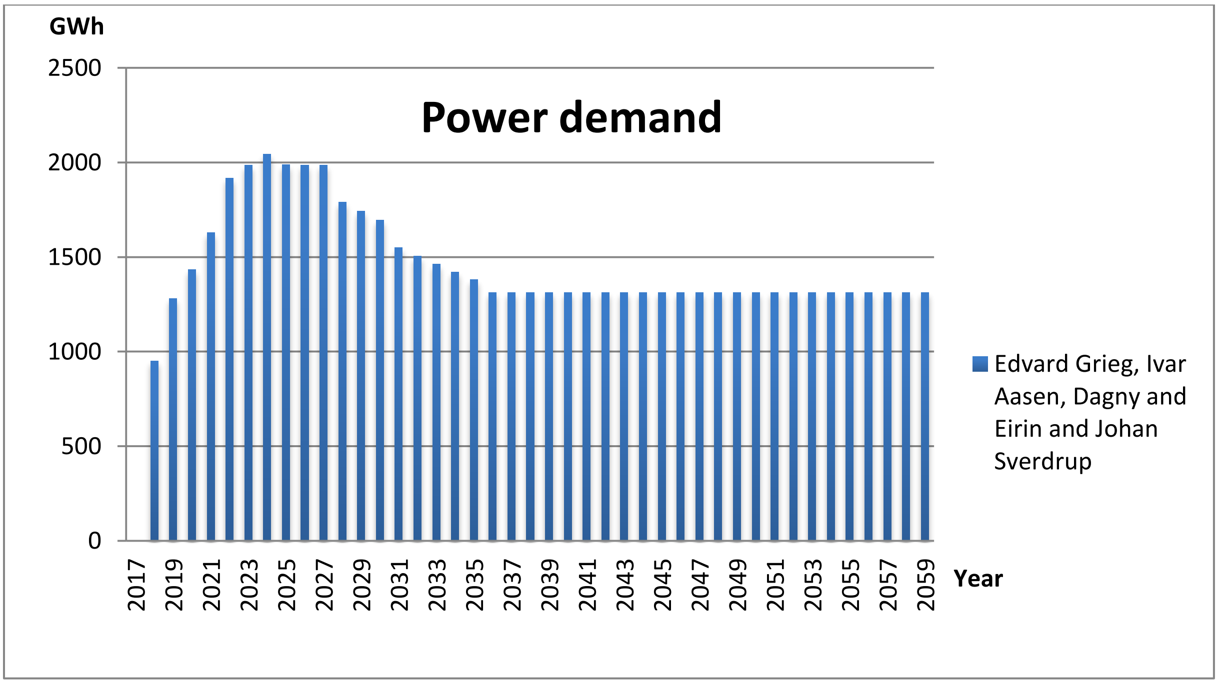

Figure 4.5 - Power demand

There is a clear peak in power demand when all fields are in their operational phase. As the smaller fields reduce their production and are shut down, the demand declines. The graph's long tail represents Johan Sverdrup's estimated demand towards the end of its lifetime.

These estimations are used in the analysis to calculate both emission reductions and electricity demand from shore when the PFS system becomes operational.

4.3.7 CAPEX

A *top-down*[32] method has been used to calculate the CAPEX of the PFS project. One of the major challenges is that there are no identical projects and therefore no exact science to estimate or predict the CAPEX. Therefore, it is natural to compare costs with similar projects conducted on the NCS. Great effort has been made to collect first hand data from market participants on Utsira High. However, much of this information is company secrets and not public information.

Add energy (2012) argues that there might be implications for the overall offshore constructions since transformers have different weight and space requirements than traditional gas turbines. However, ABB (2012) claims that this difference is negligible. Therefore, this analysis does not include these unknown costs in the estimates, but they will rather be reflected in the sensitivity analysis. The difference in costs between the two setups is also assumed to be negligible over the project's time horizon.

When it comes to land stations and submarine cables for transmission of electricity, there are mainly two large operators in the field with hands-on experience from the Norwegian market; ABB and Siemens. It has not been possible to retrieve first hand data on these costs from the firms. ABB[33] was very reluctant to share information since they are in an RFT[34] process for this project. However, add energy (2012) has supplied budgetary costs from ABB, which have been added a 25% contingency cost, and 20% for firm-specific costs. The CAPEX for the PFS-project is listed below. Both costs and savings are included.

[32] Approximating the size (duration and cost) and risk of a project by looking at the project as a whole and comparing it to similar projects or the base scenario.
[33] ABB would under no circumstances share any numbers, not even in round amounts.
[34] Request for tender.

CAPEX		
Equipment	*Mill. NOK*	*Sources*
Land Station 250MW	617.11	add energy/ABB, 2011
2x200m, 250MW submarine cable incl. Laying and cover	2496.72	add energy/ABB, 2011
Hub with transformer and AC inverter	3369.36	add energy/ABB, 2011
30MW AC cable to Dagny, 60km	554.49	add energy/ABB, 2011
75MW AC cable to Edvard Grieg	202	add energy/ABB, 2011
Receiving station Dagny	288.86	add energy/ABB, 2011
Receiving station Edvard Grieg	466.62	add energy/ABB, 2011
Receiving station Johan Sverdrup	818.1	add energy/ABB, 2011
Total costs	**8813.26**	
Savings		
Gas turbines Johan Sverdrup	2700	
Gas turbines Dagny	450	
Total savings	**3150**	
CAPEX	**5663.26**	

Table 4.8

According to Statoil (2012) there will be a phased development on Utsira High, and especially on the Johan Sverdrup field. However, the system is expected to be operational before *first oil* on Johan Sverdrup at the end of 2018. For that reason and in accordance with NPD, the CAPEX for PFS system is spread with 10%, 20%, 35% and 35% respectively over the last 4 years before production start. For simplicity, the savings are also included in this investment profile, although it could be argued that savings of gas turbines on Johan Sverdrup will be realized when the offshore facilities are constructed a few years later. The transmission cable and corresponding investment costs are likely to be taken in the first two years of the development phase. Table 4.8 shows that CAPEX amounts to approximately NOK 8.8 billion. By subtracting savings related to gas turbines, the net CAPEX for the PFS-project amounts to approximately NOK 5.7 billion.

4.3.8 Operational Expenditure

The PFS project will change the OPEX, and changes are sorted into two categories; fixed and variable OPEX. Fixed costs are mainly tied to operation and maintenance of the system and correspondingly reduced maintenance from gas turbines. Add energy (2012) reports that the transmission stations on the platforms will have costs corresponding to one fourth of a person per shift, a total of NOK 3 million per year. The hub will have operational and maintenance cost corresponding to NOK 36 million per year. The onshore transmission station will also add costs up to NOK 6 million per year. Statoil (2012) further reports that there will be offshore related savings corresponding respectively to 4% and 2% on Johan Sverdrup and Dagny and on Edvard Gried and Ivar Aasen, depending on whether the gas turbines are exluded or put on standby.

4.3.9 Fixed OPEX

The fixed OPEX related to the PFS-project amounts to NOK -96 million. This means that the PFS project will result in 96 million in savings due to high maintenance costs of gas turbines.

Fixed OPEX	
System operating costs	*Annually amount in MNOK*
Operation and maintenance of land station	6
Operation and maintenance of hub	36
Dagny	3
Edvard Grieg	3
Johan Sverdrup	9
Total increased OPEX	**57**
Savings related to operation and maintenance of gas turbines	
4% of CAPEX (Johan Sverdrup + Dagny)	126
2% of CAPEX for standby (EG + IA)	27
OPEX savings[35]	**153**
OPEX	**-96**

Table 4.9

4.3.10 Variable OPEX

The variable OPEX is composed of two factors; purchase of power from shore (NOK/kWh) and revenues from increased exports of natural gas (NOK/Sm^3). With electrification, the companies must buy electricity from the grid. This represent a new variable cost factor that

[35] (CAPEX gas turbines (JS & Dagny) * 0.04) + (CAPEX gas turbines (EG & IA)*0.02) = 153

will fluctuate with the electricity price and energy demand over the project's lifetime. This factor must be included in the analysis because it represents an outtake of power from the grid, reducing net exports of power. In times with excess power production, the cost represents outtake from the grid which would otherwise be exported to Nordic and European markets. In times of shortage, the cost represents import of power from these markets.

Natural gas which is no longer used for power production can be exported and sold on international markets. The prices of natural gas and electricity follow the price projections specified in table 4.3 and 4.4 respectively. Multiplying the price of electricity with the energy demand illustrated in figure 4.5 gives the variable OPEX for this factor. The savings due to additional export of natural gas is somewhat complicated. The total requirement for natural gas for energy production in the base case is calculated. This is done by using the estimated power demand in figure 4.5 and multiplying each year with the calorific value of natural gas. The energy composition varies among the different types of natural gas. For example, Edvard Grieg is also expected to use rich gas and LNG to produce power. These different values have been accounted for in the calculations. For each field, the total amount of natural gas required to produce the necessary amount of power in the base case is calculated. These amounts can be exported with PFS, and are therefore multiplied with the price of natural gas. Prices for rich gas and LNG from Edvard Grieg are also included. As expected, the variable OPEX is highly correlated with the power consumption profile on Utsira High.

4.3.11 Non-quantified effects of electrification

Some effects of the PFS project cannot be quantified by using traditional methods. However, main factors and their effects on abatement cost should be described and evaluated verbally. The findings should be included in the decision process. The following sections present the main factors and their effects which are not quantified in the analysis. Some of the factors suggest that the project's abatement cost is calculated too high while others suggest the opposite. For some factors, the effects on abatement cost are relatively straightforward to evaluate. Other factors have uncertain or conflicting effects that suggest that the abatement cost is calculated too high or too low, resulting in an unknown net effect.

Competition of projects and shadow prices

Depending on the level of investment activity during the time of electrification, the project has a potential of delaying or replacing alternative projects on the NCS. The capacity to execute large projects and maintenance is limited at sea. Considering that regulatory measures and HSE-related activities are prioritized, this might result in a negative effect for other projects. This results in a shadow price with an unknown, but potentially large cost for the project (NPD, 2008). Equipment, labor and management have an opportunity cost. This factor is assumed to have the largest impact on costs, assuming no idle capacity in the construction period.

This effect suggests that abatement cost is calculated: **too low**.

Environmental benefits from reducing other pollutants

Combustion of natural gas on offshore facilities emits other gases than GHGs. Emissions of these gases per Sm^3 are lower in a gas power plant on shore than on platforms. This results in a change of emissions for a range of other gases like Sulfur Dioxide, Nitrogen Oxides and particulates which are not included in the analysis. However, the reduction of these pollutants is marginal.

This effect suggests that abatement cost is calculated: **too high**

Alternative usage of cables

When trenching and laying HVDC cables it is possible to include cables for digital communication with the offshore installations. This can increase the possibility for remote control functions. Future windmill projects might benefit from the DC cables (Bellona, 2007). The main benefits from alternative use of cables will most likely be utilized many years from now and will therefore have a low present value.

This effect suggests that abatement cost is calculated: **too high**

Health, security and the environment (HSE)

According to NPD (2008), the HSE factors are likely to be improved in the operational phase. Gas turbines contribute to noise, vibrations and local air pollution on the installations. It is also a potential source for leakages, fire and explosions. Statoil, Lundin, Det Norske (2011) points out that transformers also emit noise and have potential explosion risks, but suggests that the work environment is improved with electrification. However, it is challenging to quantify this effect. Long term benefits should be compared with increased risks in the construction phase.

This factor has an **unknown** *net effect on abatement cost*

Security of supply

Utsira high has the potential to deliver significant amounts of oil and gas to Europe in the future. The recipients of gas are dependent on stable deliveries, and deviation from contracts leads to economic penalties. With electrification, the power supply to platforms is beyond the operator's control and all platforms are dependent on the same power source. Although studies from NPD (2008) show a low probability of a major failure of the system throughout its lifetime, the potential consequence of a failure becomes larger. A power loss will affect several platforms at the same time and hurt the security of supply from the area. However, backup gas turbines and *two* HCDC cables from shore decrease this risk.

This effect suggests that abatement cost is calculated: **too low**

Sunk costs in planning process

The planning process demands resources such as labor, studies, offices and travels from companies with licenses, upstream businesses and governmental institutions. However, this is considered a sunk cost when making the investment decision and will therefore be irrelevant for our analysis.

This effect suggests that abatement cost is calculated: **too low**

Economic trends and prices

The activity growth in the Norwegian economy is expected to show a moderate development going forward (SSB, 2013). This is a contrast to the economic downturn in the Euro area. The costs in our analysis are based on today's cost estimates. If current prices are above long term real price levels, the calculated costs might be too high. However, there is a constant high activity level on the NCS, reflected in stable and slightly increasing prices. Therefore, the effect of this factor seems to be marginal.

This effect suggests that abatement cost is calculated: **too high**

Extended operational phase

As described in chapter 2.6.1, the power demand generally increases when fields enter the mature state. With electrification, power consumption can be scaled up without further investments. The operating costs are also expected to decrease with PFS which might extend the operational phase. However, the effect on the NPV will be small when considering the long time horizon and the discount factor.

This effect suggests that abatement cost is calculated: **too high**

Other environmental concerns

Laying and trenching of cables may have negative effects for fish, corals and other organisms (Statoil, 2012), but these effects are difficult to quantify and not considered very high.

This effect suggests that abatement cost is calculated: **too low**

New discoveries

Future discovery of nearby fields and establishment of offshore facilities might benefit from the project, as it could connect to the existing system instead of investing in gas turbines. However, the discovery of future fields is uncertain and the systems' capacity might need to be upgraded.

This effect suggests that abatement cost is calculated: **too high**

As described in previous sections, some factors suggest that the abatement cost is calculated too high while others argue the opposite. However, the potential impact of the different effects is likely to have large variations. A further estimate of the relative impacts is beyond the scope of this thesis. All presented factors have high degrees of uncertainty. With limited information, it is challenging to use these findings in the decision process. As some factors potentially have large impacts on total costs, we strongly suggest that in-depth analyzes should be carried out by the companies and authorities. However, for the purpose of this thesis it is reasonable to assume that the non-quantified effects cancel themselves out, leading to a net effect of zero.

4.4 Step 4: Calculate the costs, utility and present the results

This step presents the main findings of the analysis. The final result of abatement cost per ton CO_2 has been calculated by applying all previous assumptions and the use of a comprehensive model in Excel. Before the results are revealed however, the choice of NPV method and the valuation of utility and benefit of reduced emissions will be described in more detail.

4.4.1 Net Present Value vs. Annuity

In order to determine the Norwegian economy's costs and utility of a PFS project on Utsira High, the Net Present Value (NPV) method or the Annuity method can be applied. A presentation of the different methods and a discussion of final choice are outlined in the following sections. The NPV method used in this analysis is formally derived below and compared with the annuity method to highlight the factors that makes the NPV method more applicable.

The NPV method

The costs and benefits of the PFS project do not occur at the same time. Therefore, the analysis requires a method which allows us to compare and sum the effects that are unevenly distributed in the project's lifetime. The most common method for such a comparison is to convert the yearly cost and benefit effects to a net present value (Norwegian Ministry of Finance, 2005). The net present value represents the total costs and benefits that occur in separate periods. By calculating the NPV of the project, future effects are discounted with a positive discount rate. As a consequence, the effects diminish with the time horizon.

The NPV of the project's costs can be derived as following formula: I is the net CAPEX, O_{Fix} is net fixed OPEX and O_{Var} is net variable OPEX. Savings due to the electrification project is implemented in the variables.

$$(1)\ NPV = \sum_{t}^{T} \left(\frac{1}{(1+r)^t} \left(I_t + O_{Fix\,(t)} + O_{Var\,(t)} \right) \right)$$

All amounts are discounted by a discount rate (r) over the project's lifetime (T). As previously noted, the PFS project's relevant time period is from 2013 to 2059. The correct choice of discount rate was previously discussed in part 4.3.5, and NPD recommend a 5% discount rate for electrification projects. Investments occur in the years 2014-2017. O_{Fix} has fixed values from 2018-2059. O_{Var} has variable values in the period 2018-2059 depending on the level of electricity demand and exports.

The NPV of the project's costs can be compared with the utility from reduced emissions. For the period t=0…T, the estimated emission reductions (X_t) of CO_2 have been calculated. The factor q_t is the utility of one ton of reduced emissions. The NPV of this utility can be calculated by:

$$(3)\ Utility\ from\ the\ amount\ of\ reduced\ emissions = \sum_{t=0}^{T} \left(\frac{1}{(1+r)^t}\ q_t X_t\right)$$

The NPV of costs are compared with the NPV of utility. If the NPV of emission reductions is higher than the NPV of the project, the solution is will result in economic profitability.

$$(4) \sum_{t=0}^{T} \left(\frac{1}{(1+r)^t}\ q_t X_t\right) \geq \sum_{t=0}^{T} \left(\frac{1}{(1+r)^t}\ (I_t + O_{Fix\,(t)} + O_{Var\,(t)})\right)$$

By applying a constant price for the utility ($q = q_t$), equation 3 can be formulated as:

$$(5)\text{Utility from amount of reduced emissions } = q \sum_{t=0}^{T} \left(\frac{1}{(1+r)^t}\ X_t\right)$$

Inserting equation 5 into equation 4 and dividing with $\sum_{t=0}^{T} \left(\frac{1}{(1+r)^t}\ X_t\right)$ on both sides results in equation 6. The factor q* is NPV of the project's costs divided by discounted total emissions, given in NOK/ton CO_2 reduced. It is the project's abatement cost per ton CO_2. The formal interpretation of the equation is: *if the decision maker's valuation of the good X (q) is bigger or equal to q* the project is profitable.*

$$(6)\ q \geq q^* = \frac{\sum_{t=0}^{T}\left(\frac{1}{(1+r)^t}\ (I_t + O_{Fix\,(t)} + O_{Var\,(t)})\right)}{\sum_{t=0}^{T}\left(\frac{1}{(1+r)^t}\ X_t\right)}$$

The equation shows that the decision maker will have to evaluate whether the project results in economic profitability based on the valuation of the good X.

The Annuity Method

It is possible to calculate the results by using the annuity method. For projects with short lifetime and steady emissions the two methods will yield the same results. The annuity method focuses on a base year when the project has been implemented (not necessarily the first year of the project). Instead of only using the investment cost we now look at the annuity "a_t"[36].

$$(7)\ a_t = \frac{Ir}{(1 - \frac{1}{(1+r)^T})}$$

The annuity is then applied with changes in yearly income and operational expenses to calculate yearly additional costs caused by the project.

$$(8) Yearly\ additional\ costs = \ a_t + O^*_{Fix(t)} + \ O^*_{Var(t)}$$

$$(9) Emissions\ in\ reference\ year = X^*$$

The cost of the project is found in the following way.

$$\text{Abatement Cost} = \frac{Yearly\ additional\ cost}{Emission\ reference\ year} = \frac{a_t + O^*_{Fix(t)} + \ O^*_{Var(t)}}{X^*}$$

Comparing the methods

The main difference between the methods is that the annuity method does not discount the environmental utility. The normal procedure for present value calculations is to discount the environmental utility in the same manner as the cash flow. However, it can be argued that the utility factor should be discounted with a lower rate or not discounted at all. For the

[36] The annuity factor is derived in Appendix 8.7

robustness of the annuity method it is recommended to use average calculations for X*, $O^{*}_{Fix(t)}$ and $O^{*}_{Var(t)}$ instead of the given reference year value. The annuity method can then easily be adjusted for larger changes in emissions or costs caused by the investment. However, we argue that this does not represent a realistic situation, so that the NPV method is a better fit with the production and energy consumption profile on Utsira High. The yearly variations of energy consumption on Utsira High are high due to the relatively short production profiles on Edvard Grieg, Ivar Aasen and Dagny compared to Johan Sverdrup. The annuity method would be more applicable if only analyzing one of these facilities, because the power consumption profile is relatively stable throughout the lifetime of an individual facility (Ubbe, 2013). The NPV method is therefore used to value the costs and benefits of this project. With the exception of Klif, this is also the most used method by market participants in similar analyses.

The NPV method requires a reasonable measurement of benefit per ton CO_2 reduced, denoted by the value of q in equation 6 above. The following sections will give a description and the rationale behind the analysis' valuation of q. As will become clear, the correct valuation of the utility factor depends on what the analysis is meant to answer. While this thesis uses the price on EU ETS allowances[37], above formulas can also be applied by decision makers who make different assumptions about this factor. In a world with perfect information, the factor q would represent the true utility of emission reductions.

4.4.2 Choice of utility factor

The following sections argue that the price of EU ETS allowances is the correct comparison with the abatement cost of the PFS project in order to determine its cost efficiency. The choice is based on recommendations from NOU: 16, prepared by the Norwegian Ministry of Finance in 2012. The Ministry of Finance's framework for economic analyses also supports this approach.

NOU: 16 points out that the correct valuation of emissions depends on current national and international climate policies and how these policies will change in the future. In addition to binding agreements through the Kyoto Protocol, Norway has non-binding long term goals of reducing up to two thirds of Norwegian emissions within national borders. This implies a

[37] Also referred to as the carbon price

national emissions reduction of 12 million tons of CO_2 within Norwegian borders by 2020. These goals are specified in the Climate Agreement of 2012. However, NOU: 16 points out that existing fees are currently not adjusted to reflect the goals specified in the Climate Agreement of 2012. On this basis, NOU: 16 specifies that the national goals in the Climate Agreement of 2012 cannot currently be accounted as binding commitments of Norwegian emissions. However, if the national goals become binding commitments in the future, NOU: 16 points out that this hypothetical situation suggests that a project's national emissions must be compensated by national abatement, independent of whether the cost is higher than the price of EU ETS allowances. As mentioned, Climate Cure 2020 (2010) evaluates measures in order to reach the goals specified in the Climate Agreement of 2012. Measures with an abatement cost up to NOK 1100 per ton CO_2 must be implemented in Norway in order to reach these goals. If the goals specified in the Climate Agreement of 2012 become binding in the future, this would be the correct price to value emissions when evaluating environmental measures in Norway. In this hypothetical situation, NOK 1100 per ton CO_2 would have become the relevant utility factor for this analysis.

NOU: 16 establish that correct valuation of the utility factor must be based on existing and binding commitments of the Kyoto Protocol rather than on other national long term goals specified in the Climate Agreement from 2012. Again, this is because the national goals of the Climate Agreement of 2012 *cannot currently be considered as formally established agreements.*

How Norway is fulfilling its international commitments should be the basis for valuation of GHG emissions. Norway is committed through the Kyoto protocol and the government has the opportunity to purchase allowances in the European carbon market. NOU: 16 concludes that when considering the currently established and binding climate commitments, the cost-efficient approach to reduce emissions is to implement measures with a cost that is lower than the price of EU ETS allowances. After this, the outstanding emission reductions to reach the targets should be covered through purchasing allowances in the European carbon market. When considering the current binding commitments of Norway, this is the correct approach to evaluate the cost efficiency of the PFS project.

The price of EU ETS allowances should be based on market expectations for future carbon prices. For years when prices are not quoted, NOU: 16 specify that the price trajectory over time should approach an assumed two degree trajectory based on international recognized models. As will be explained in the next part, we will apply price trajectories supplied from Point Carbon and Climate Cure 2020. This is in compliance with recommendations from NOU: 16.

4.4.3 Result

The abatement cost has been calculated in accordance with all the assumptions presented in chapter 4.3 and the given emission profile on Utsira High.

Result		
Accumulated		
Total lifetime project cost	30 909	Mill. NOK
CO_2 reduction	31.91	mill. ton CO_2
Discounted		
NPV of project cash flow	13 313	mill. NOK
NPV of project CO_2-flow	11.44	mill. Ton CO_2
ABATEMENT COST[38]	**1163.37**	**NOK/ton CO_2**

Table 4.10

The PFS-project abatement cost is NOK 1163.37 per ton CO_2. Over the project's lifetime CO_2-emissions is reduced by almost 32 million tons, an average reduction of 0.76 million tons of CO_2 annually. The NPV of the PFS-project's cash flows gives a cost of approximately NOK 13.3 billion.

The result that has been calculated above must be compared with the price of EU ETS allowances. As mentioned above, this is the correct method to determine the cost efficiency of the PFS project. Rather than comparing with the current price of allowances, NOU: 16 (2012) states that the comparison should be made on future price expectations. The trajectory for future price expectations of allowances is illustrated below:

[38] $Abatement\ Cost = \frac{NPV\ of\ project\ cash\ flow}{NPV\ of\ project\ CO_2{-}flow} = \frac{13\,313\ mill\ NOK}{11.44\ mill\ ton\ CO_2} = 1163.37\ \frac{NOK}{ton\ CO_2}$

	2015	2020
Low	130	153
Medium	198	305
High	290	458

Table 4.11 – Future carbon prices (NOK/ton). Source: Climate Cure 2020 (2010)

The different price trajectories from Climate Cure 2020 (2010) will not be discussed thoroughly, but they are mainly based on the necessary price in order to meet the most ambitious emissions targets in the EU. The estimations have been supplied by Point Carbon. As discussed in chapter 4.3.4, a growth rate of 39.7% in the period 2013-2020 is calculated to meet the medium scenario. These growth rates can be argued to be high and might not reflect expectations in the carbon market. For this analysis they rather serve as the maximum prices to use as comparison with the abatement cost per ton CO_2. Again, the Norwegian government explains in NOU 2012: 16 the reason why it is correct to apply these price projections: "*If the Norwegian binding targets is related to the total, global emissions Norway causes, and Norwegian emissions are subject to an international cap and trade system, the estimated price for GHG emissions should be based on expectations about the international carbon price. Of the different prices in todays' international cap and trade markets the committee recommends to use EU's carbon price. The price trajectory should be based on the markets expectations for future carbon prices. For years when prices are not quoted the price trajectory over time should approach an assumed two degree trajectory based on international recognized models*" (NOU 2012: 16). On May 8th, 2013, the price stood at NOK 28.66 per ton CO_2 (Point Carbon, 2013). The price of EU ETS allowances has been declining in recent years. This has been discussed in chapter 2.3.4 where the economic crisis was held as one of the main reasons for a large surplus in allowances with a correspondingly low price for EU ETS allowances. Due to long term effects of this surplus, the market price of allowances is expected to remain at a low level for the next couple of years (European Commission, 2012). However, due to the lack of trajectories for the market expectations of the carbon price, we use the trajectories supplied by Climate Cure 2020 (2010). This is done in compliance with NOU 2012: 16 when future prices are not quoted. It should be noted that not even the highest carbon price trajectory estimate for 2020 would lead a situation where the abatement cost is lower than the carbon price. Climate Cure 2020 (2010) has together with Point Carbon estimated a carbon price for 2030 to be somewhere around NOK 763 per ton CO_2. The estimate is naturally based on a tighter regulation of emissions an even higher willingness to commit from nations than what currently applies. The abatement cost of the PFS project is calculated to NOK 1163.37 per ton CO_2, far above future estimations of the price of EU ETS allowances. On this basis, the PFS project is not a cost-efficient climate measure for the Norwegian economy.

Several of our assumptions are subject to uncertainty. In step 5, this uncertainty will be highlighted. A sensitivity analysis has been conducted to verify the robustness of the result and to identify the factors with highest uncertainty and the project's sensitivity to certain factors. These factors are tied to our result and will be evaluated and discussed in the next step.

The sensitivity analysis has been conducted by changing[39] the following factors:

1. Gas turbine efficiency
2. Electricity price
3. Calorific value of natural gas (upper and lower values)
4. CAPEX
5. Price of natural gas
6. Discount rate
7. Energy demand
8. Time horizon of production (+/- 10 years)
9. Fixed OPEX
10. Transfer loss
11. Heating requirement

4.5 Step 5: Highlight uncertainties

A sensitivity analysis is conducted in order to highlight uncertainties of the PFS-project's abatement cost and to identify the most important cost drivers of the project. The PFS-project has an abatement cost of NOK 1163.37 per ton CO_2. By increasing or decreasing the

[39] Change refers to a ± 25% up and down adjustment in the given factor except for calorific value of natural gas and the time horizon of production.

different cost factors by 25%, their impact is measured from the percentage change in abatement cost (NOK/ton CO_2). The tornado chart below demonstrates the result from the sensitivity analysis. The chart is intuitive with the strongest cost drivers placed on the upper half of the tornado chart. On the lower half we find the cost drivers which do not have significant impact on the abatement cost. In order to measure the individual impact on the result, the factors are changed individually by ±25% while all other factors are held constant. Some factors relate to each other and changes in one factor could result in changes in others. The sensitivity analysis does not take such correlated changes into account. The purpose of the sensitivity analysis is however to point out the most important cost drivers of the PFS-project.

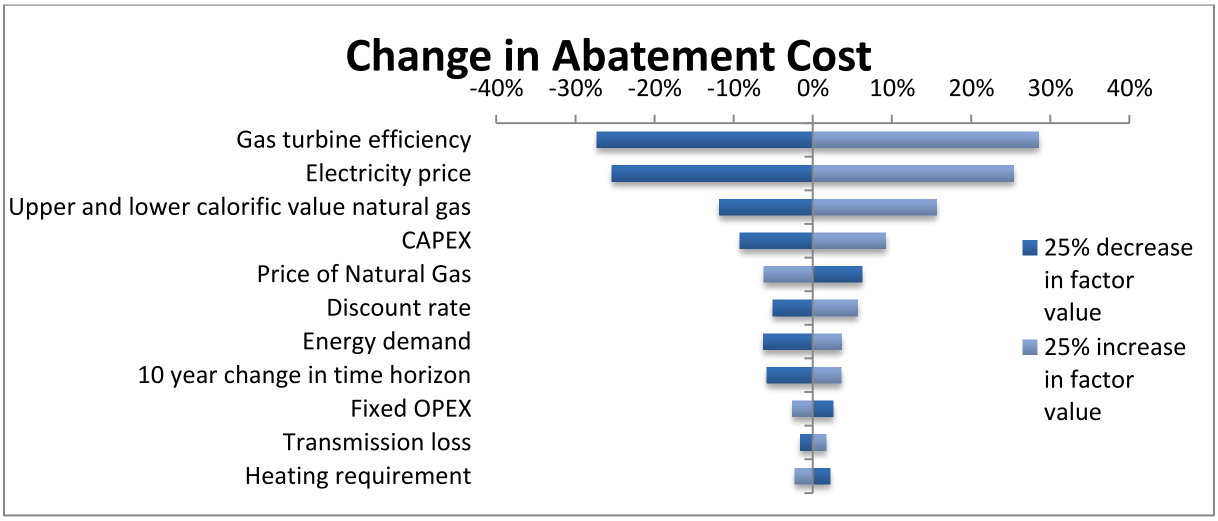

Figure 4.6 - Results of sensitivity analysis

The gas turbine efficiency reflects the percentage of energy which can be transformed into electric energy from chemical energy in natural gas. The amount of natural gas that is needed to meet the energy demand on the different installations is highly dependent on this factor. A higher efficiency rate will reduce the amount of natural gas needed to meet the energy demand without electrification, leading to less potential CO_2 reduction and lower amounts of natural gas available for sale with electrification. The chart shows that higher or lower efficiency from the gas turbines will affect the abatement cost per ton CO_2 ± almost 30% in either direction. The market for gas turbines is a well-established market and there are few indications on that we will see dramatic changes in the gas turbine efficiency. In the absence of dramatic improvements, it is unrealistic to assume that the gas turbines on the offshore facilities would be replaced within the operational phase. Even though an efficiency change could have a large impact on the project, the risk for it happening is close to negligible.

The electricity price is one of the most important cost drivers, having in mind that the PFS-project means that companies must buy electricity from the grid. The measured changes in the electricity price shifts the abatement cost ±25% per ton CO_2, and shows that the project is vulnerable to high electricity prices. With the time horizon connected to this project it is not only hard but close to impossible to predict the electricity price. However, the electricity price contains unsystematic risk which is possible to diversify and hedge against through market mechanisms such as Nord Pool Spot and avoid unforeseen price fluctuations. It is also likely that major market participants have the possibility to buy electricity on better terms than the average spot price and on longer term contracts, lowering the risk tied to power from shore dependency.

The calorific value of the natural gas has a large impact on the PFS-project abatement cost. The calorific value in the sensitivity analysis is based on the lower and upper calorific values listed from Europipe II and Ivar Aasen, with respectively 9.73 kWh/Sm^3 and 12.12 kWh/Sm^3. These values affect the abatement cost from a 12% decrease to a 16% increase. The calorific value mirrors a part of the efficiency by burning natural gas and therefore a part of how much natural gas that is available for export after the electrification. Johan Sverdrup and Dagny will use imported Europipe II natural gas and Edvard Grieg will use natural gas imported from Ivar Aasen.

The *CAPEX* accounts for a major part of the project expenses and represents one of the main sources of uncertainty. The analysis shows that a 25% change in CAPEX affects the abatement cost by about 10%. In the analysis, CAPEX for the PFS system is provided by add energy (2012) and is based on preliminary budgetary bids from ABB. High uncertainty is bound to these prices and whether the offshore hub will be integrated on an offshore facility or built separately. Uncertainty is linked to the cost of gas turbines and the corresponding savings from the implementation of the PFS system. Future analyses with credible information about the costs of PFS system and gas turbines will represent less uncertainty. For this analysis however, this uncertainty is covered through the sensitivity analysis. A 25% change in CAPEX will to a certain extent affect the companies' budgets more than the abatement cost result and naturally be an important factor in the decision process in the fall of 2013.

The *price of natural gas* affects the amount of income from exports. The abatement cost changes with ±6% due to the measured changes in the price of natural gas. The price is included in the sensitivity analysis since it is a contributor to the income which is part of the variable OPEX stretching over the lifetime of the project. The price uncertainty in the future is significant. The exploitation of shale gas in the US and its effect on the price of natural gas and other fossil fuels is an example of development which represents uncertainty for future prices. The price is also affected by price developments of other fuels and energy sources. These are just some of the factors which will continue to have impact on the price. Despite the high uncertainty, a 25% change does not change the result of the analysis.

The *Discount rate* is linked to some uncertainty, but the effect of changes is captured in the sensitivity analysis. The changes in the factor results in ±5-6% changes in the abatement cost. Major market participants such as Statoil are able borrow money in the market at extremely good conditions with yield to maturity lower than 2% in the short term (Morningstar, 2013). Therefore, they are seen as low risk customers for the government and the banking industry. On the other hand, the company's and shareholder's expectations to return on capital will affect the discount rate in the other direction.

At the bottom part of the tornado chart we find the *time horizon* (±10 years), *fixed OPEX*, *transfer loss* and the *heating requirement* at the installations. The analysis shows that none of these factors changes the abatement cost more than 6% and often less than that. They are all seen as low risk components of the project.

In conclusion, the sensitivity analysis does not change our result. None of the identified factors will reduce the project's abatement cost to a lower level than the price of EU ETS allowances by assuming a 25% change.

4.6 Step 6: Total evaluation and recommendation

The abatement cost has been calculated for the PFS project on Utsira High and found to be NOK 1163.37 per ton CO_2. Comparing this with the price of EU ETS allowances, the PFS project on Utsira High is not a cost-efficient measure and will not be profitable for the

Norwegian economy. The costs heavily outweigh the benefits of emission reductions. At current prices, the cost-efficient solution would rather be to buy allowances equivalent to the estimated emission reductions of the PFS project.

The measure itself will over the lifetime of the project reduce CO_2-emissions with 0.76 million tons annually within Norway and the Norwegian continental shelf. The national non-binding 2020-target is to reduce annual national emissions with 12 million tons[40] of CO_2. The PFS-project at Utsira High therefore amounts to just above 6%[41] of the annual needed emission reductions. Climate Cure 2020's overview of measures needed to reach the 2020 goals suggests implementation of all measures with abatement cost up to NOK 1100 per ton CO_2. This places the PFS project around the upper limit of necessary projects that should be implemented in order to reach these goals[42]. This might be an obvious reason for the environmental organizations' interest in the project.

The sensitivity analysis has underlined the robustness of our result. It shows that no changes within reasonable limits in any single factor could impair the result so that the project itself becomes economically profitable. None of the factors within a 25% change adjust the abatement cost into the estimated price trajectory of EU ETS allowances. There could, however, be several scenarios consistent of two or more factors that together are able to adjust the result further than the results from the sensitivity analysis. A lower calorific value of natural gas, lower turbine efficiency and lower electricity prices would naturally lead to a low abatement cost of the project. However, there will not be conducted scenario analyses in this thesis, as we consider the sensitivity analysis to be sufficient in order to highlight the uncertainty and identify factors of importance.

To conclude, a PFS project on Utsira High is not recommended on the basis of cost efficiency. The project is not profitable for the Norwegian economy.

[40] 15 million minus 3 million from forestry.

[41] Note that this percentage will be slightly less because emissions from the Johan Sverdrup field is not included in the targets.

[42] Accounting for an approximate calculation of 1100 and uncertainties in our abatement cost calculation.

5. Effects on European Emissions

This chapter focuses on the second stated problem of this thesis: **What is the PFS project's effect on European emissions?** The final part of this chapter will compare these findings with results from the analysis and give a final evaluation of the project.

The international effect on emissions from the PFS project is influenced by the characteristics of the European power market and the European market for CO_2 allowances. Understanding how these two markets work is thus of high importance when describing the effects on European emissions. Attention to these markets was given in part 2.3.4 and 2.7 in order to provide the reader with necessary knowledge in order to comprehend the international emission effects of a PFS project on Utsira High.

5.1 Main arguments:

Part 2.7.2 described the interrelation between Nordic and European power markets and the individual countries within. The strong correlation between power production and emissions was also highlighted. Norway is integrated in the Nordic and European power markets, using export and import to uphold the instantaneous balance, stabilizing the grid and improving security of supply. As figure 2.11 illustrates, Norway occasionally has a negative net export of power, meaning that import is larger than export. The power production profile in Europe is dominated by thermal power plants (Eurostat, 2012). As a consequence, Norway will naturally be importing a large fraction of thermal power with high levels of CO_2 emissions. With the PFS project, offshore facilities on Utsira High will tap power from the Norwegian central grid. Environmental organizations and other stakeholders argue that this power will mainly come from clean hydropower, eliminating CO_2 emissions (Zero, 2011). However, Norway's participation in the Nordic and European power market weakens this argument as the PFS project is likely to have a direct effect on Norwegian net exports of power. As a consequence, the reduced emissions on Utsira High might be offset by increased import of emission intensive thermal power from European markets. The transmission capacity between Norway and these markets is about 5400MW, or 17.5% of Norwegian power production (OED, 2013). This constraint on the transmission capacity naturally limits the amount of imports of thermal power. If the international transmission is at its peak, power demand from Utsira High will be covered through higher power production in Norway. Thus, the effect on European emissions will depend on the initial transmission between Norway and neighboring countries. Further studies are required to estimate how this effect will vary and will not be further discussed in this thesis. However, increasing integration of power markets and the participating countries in the future may lead to a dynamic market which will strengthen the European emission effects of the PFS project. With accelerating integration and continued use of thermal power in Europe, the reduced emissions on Utsira High may be offset by increased emissions elsewhere on the continent.

As described in the analysis, the PFS system reduces consumption of natural gas for power generation on the offshore facilities. This natural gas is likely to be exported to European markets, representing increased revenue for producers on the NCS and the government. The majority of this natural gas will most likely be used for power generation on the continent. The average onshore gas power plant in Western Europe is assumed to have a higher efficiency than the offshore gas turbines, meaning that less CO_2 is emitted per watt produced. Zero (2011) argues that the onshore efficiency is up to twice as high as in offshore power plants. Sintef (2008) also informs that operators of gas power plants on the continent have reported efficiency up to 58.4% in optimal production conditions. We find it appropriate to base the comparison of onshore and offshore gas turbines on the *average* efficiency in Western Europe, estimated to 38% (Dones et. al, 2005). With our assumption of 35% efficiency of offshore gas turbines, this only represents a marginal increase. The effect on European emissions will naturally correspond to the small difference in gas turbine efficiency. Improved average efficiency of onshore power plants and large scale implementation of CCS are possibilities which may change the effect on European emissions in the future. However, in the current state it is reasonable to assume that the reduced national emissions from combustion of natural gas are offset by combustion elsewhere in Europe. Considering the small difference in gas turbine efficiencies, the net reduction of European emissions is marginal at best.

On request from Statoil, Pöyry Management Consulting in 2011 released a report on the CO_2 effects from an electrification of Edvard Grieg, Ivar Aasen and Dagny. The report focuses both on the effects of national and European emissions. One of the scenarios was based on power supply from the central grid, the same approach used in this thesis[43]. Due to the similarities in scenario, assumptions and choice of facilities for this case study, the report is of high relevance for this thesis. Attention will therefore be given to its main findings.

5.2 The Pöyry report

The focus of the report is to quantify and describe effects from five alternatives for power supply to Dagny, Edvard Grieg and Ivar Aasen[44], what the difference in CO_2 emissions will be over the life time of the project (Pöyry, 2011). The five alternatives are listed below:

1. Standard offshore gas turbines.
2. Cable from the onshore power grid, via offshore hub/sub-station.
3. Cable from dedicated, new-built onshore gas power plant, via offshore hub/sub-station.
4. Offshore gas turbines, optimized for low fuel consumption and low emissions of greenhouse gas.
5. Cable from the onshore power grid, but with 50% of annual supply from offshore wind park.

Focus will only be put on results from alternative 1 and 2 which respectively relates to our base scenario and alternative solution with PFS. The difference is calculated by summarizing the emissions from the source of power production and life time emissions from the power supply equipment in each alternative. The focus of the analysis is therefore on the factors and components that differ between the alternatives (Pöyry, 2011).

5.2.1 The BID model

European power markets consist of many power plants with different characteristics. A qualitative assessment of how power plants will react to increased demand is likely to be of a general nature and inadequate to yield a precise estimate of how electrification will alter emission levels (Pöyry, 2011). The Better Investment Decision (BID) model has therefore been used for a comprehensive power market simulation.

[43] When referring to the report from Pöyry, only findings on this scenario will be presented.
[44] Draupne and Luno have been named respectively Ivar Aasen and Edvard Grieg since the report was released in 2011.

The BID model is an optimization market simulator for the North-West Europe (including the Baltics and Poland), meaning that it finds the lowest price necessary to balance the power market given the supply and demand. The model also accounts for the following factors:

- Running costs of power plants; fuel prices, adjusting generation up and down. BID will choose the plant with lowest costs.
- Inflexibility of renewable generation and that generation is not adjusted in line with demand.
- The price the owner of reservoir hydro-plant receives and that opportunity to store or produce at any hour.
- Transmission constraints.

As the BID model assumes a perfect market with no market-power, the most expensive (marginal) plant will get a power price that covers its production costs, but no more. The BID model simulates the power markets in a very accurate and realistic way[45] (Pöyry, 2011).

5.2.3 Findings and Conclusion

Electrification will yield lower CO_2 emissions from power supply compared to onsite gas-fired power generation (Pöyry, 2011). This is caused by assuming that relatively inefficient offshore gas turbines in the case of electrification is changed with onshore CCGTs, which can generate the same amount of power as on-site turbines using less natural gas, thus emitting less CO_2.

Connecting offshore installations to the central grid means that power originates from generation based on renewable sources. National CO_2 emissions are therefore reduced. However, reductions in national CO_2 emissions are partly offset by increased emissions from European replacement power (Pöyry, 2011). Therefore, the global reductions of CO_2 are substantially lower when the European power market is taken into account. Increased electricity demand in Norway reduces Norwegian exports of hydropower and the replacement power in the European market will mostly be generated from fossil-based power plants. The results from the optimization modeling done by ECON-Pöyry's BID model are displayed below:

[45] Confirmed by Econ Pöyry's backtesting exercises of the model

	Base case	Electrification
European emissions	7.82	5.39
National emissions	7.82	1.78

Table 5.1 – Accumulated European and national emissions from supplying power during the operational phase to Dagny Edvard Grieg and Ivar Aasen (million tons CO_2). Source: Pöyry Management Consulting analysis, 2011

The result in table 5.1 shows that there will be a reduction in emissions from power generation in Europe due to the power from shore project. Over the 20 years lifetime of the project from 2015 to 2035 emissions from power generation in Europe will reduced with 2.4 million ton CO_2. The reductions of European emissions in the BID model's results are mainly because the model assumes a relatively large difference between the gas turbine efficiency of onshore gas power plants on the continent and offshore gas turbines on the NCS. Despite the results of the model, Pöyry argues that European emissions will not be reduced as a result of the PFS project; after the installations has been electrified it follows that an amount of CO_2 allowances now becomes available in the EU ETS market. Therefore the amount of allowances available to the market will continue to correspond with the EU emission target regardless of electrification (Pöyry, 2011). It follows from basic economic theory that with increased supply of CO_2 allowances the price for allowances and CO_2 emissions is likely to decrease. The result is that emission intensive power production from for example coal power plants becomes relatively cheaper with the reduced price of allowances. As a consequence, total European emissions increase or remain constant due to the power from shore project.

Pöyry's report shows that the effect on European emissions is considerable less than the effect on national emissions. Some of the report's assumptions may differ from assumptions made in this thesis, and we do not possess in-depth knowledge about the full extent of the BID model. However, it is rational to assume that a similar effect will be observed if the analysis had included the Johan Sverdrup field. The main differences may have been a longer production profile with correspondingly higher power demand. We therefore find the results from the Pöyry report highly relevant in order to explain the European effects of the PFS project on Utsira High.

When considering the high costs of electrification and its relatively small reduction of European emissions, it may be difficult to justify these costs from a climate perspective.

Consider Europe as a country on its own. If Europe had implemented the PFS project, the high cost of the project would have been divided by reduced emissions to obtain the abatement cost. This abatement cost would have been significantly higher than the Norwegian abatement cost of NOK 1163.47 per ton CO_2 reduced. The point is that the abatement cost of reducing European emissions is much higher per ton CO_2 than when solely focusing on Norwegian reductions.

The results from the Pöyry report confirm the main arguments at the start of this chapter. The additional natural gas available for export will lead to a marginal decrease in European emissions, assuming a higher efficiency of onshore than offshore gas turbines. However, Pöyry does not supply their estimate of this difference in efficiency. This thesis argues that average efficiency of onshore gas power plants in Western Europe (38%) should be used as comparison with the listed efficiency of the offshore LM2500 gas turbines (35%). Under this assumption, the decrease of European emissions is marginal at best. Pöyry also support our argument that the PFS project will lead to reduced net export of power from Norway. In the short term, the price of EU ETS allowances and coal is expected to be low. By removing a share of Norwegian exports, the European power market is likely to increase the use of coal power plants since this is the marginal technology (Løfsnæs, 2012). This will lead to a net increase of emissions on the continent. However, if the price of allowances will increase to a level that makes gas power the marginal technology, a PFS project may have a reducing effect on the total emissions in Europe (Løfsnæs, 2012). In conclusion, the background knowledge has enabled us to draw valid arguments on the European emission effects of a PFS project on Utsira High. These arguments are supported by recent research in the area. Although the effect will depend on a range of factors, we have shown that the net reductions of European emissions will be marginal at best. In the short run, the PFS project may even result in increased emissions on the continent.

5.3 Concluding remarks

When involved companies and the authorities evaluate the implementation of a PFS project on Utsira High in the fall of 2013, they will be faced with a range of factors to consider. This thesis has shown that the measure is not cost-efficient and is unlikely to reduce European emissions. The price of EU ETS allowances must increase to a level above the abatement cost in order to make the PFS project a cost-efficient measure in Norway. The allowances which no longer will be required must be removed from the carbon market in order to obtain European emission reductions.

Tradable emission quotas, fees and implementation of projects with an abatement cost less than the price of EU ETS allowances are examples of cost-efficient measures because they lead to a situation where the actors are conducting abatement on their own initiative. Additional measures within the carbon market will generally not lead to a net reduction of emissions but rather change the location of the emitting sources. When focusing on the binding climate agreements which currently exist, namely the Kyoto Protocol, our findings in chapter 4 and 5 show that a PFS project on Utsira High is not an efficient solution to reduce global emissions.

Leading by example is a central objective in the Norwegian climate policy, and policy makers argue that other countries will be motivated to follow countries which show strong political will to reduce emissions. By implementing costly abatement measures, policy makers argue that Norway may obtain a larger impact in future climate negotiations and stimulate other countries to follow a good example. Through the Climate Agreement of 2012, Norway has non-binding long term goals of reducing national emissions within Norwegian borders by 12 million tons of CO_2 within 2020. If these goals from the Climate Agreement of 2012 become binding commitments in the future, this will change the valuation of emissions, or the utility factor, when deciding the cost efficiency of a project. The necessary abatement cost in order to meet the goals of the Climate Agreement of 2012 is calculated in Climate Cure 2020 (2010) to be NOK 1100 per ton CO_2 reduced. This hypothetical situation requires that the authorities apply this price instead of the price of EU ETS allowances when evaluating climate measures. This discussion merely points out that it is important to emphasize that national and international climate policies are constantly changing. If the national abatement goals specified in the Climate Agreement of 2012 becomes binding in the future, the PFS project on Utsira High may be evaluated as a cost efficient measure to reduce national emissions. This is because the project's calculated abatement cost of NOK 1163.37 is close to, and in some situations below, the necessary abatement cost of NOK 1100, emphasizing uncertainty in our calculations and results from the sensitivity analysis.

However, with current exisiting and binding commitments through the Kyoto Protocol, the implementation of the PFS project is not a cost-efficient solution for the Norwegian economy. It is also unlikely that the measure will result in a reduction of European emissions. In the fall of 2013, the involved companies on Utsira High will base their decision of PFS on their own profitability analyses. As the authorities evaluate the investment decision, it will be interesting to observe if political targets is prioritized above global emission reductions and if cost efficiency is set aside in favor of ineffectual policies specified in the Climate Agreement of 2012.

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7. Abbreviations

AC – Alternating Current

bbl- Barrel of oil (United Kingdom)

BID – Better Investment Decision

CAPEX – Capital Expenditure

CCS – Carbon Capture and Storage

CDIAC – Carbon Dioxide Information Analysis Center

CER- Certified Emission Reduction

CO_2 – Carbon Dioxide

CO2e - CO2 equivalent unit

COP – Conference Of the Parties

DC – Direct current

DFØ – The Norwegian Government Agency for Financial Management

EITs – Economies in Transition

ERUs – Emission Reduction Units

ESRL – Earth System Research Laboratory

EU – European Union

EU ETS – European Union Emissions Trading Scheme

EUA – European Union Allowance

GE – General Electric

GHG – Greenhouse gases

GNP – Gross National Product

GWh - Gigawatt hour

GWP – Global Warming Potential

HVDC –High Voltage Direct Current

IPCC – International Panel on Climate Change

JI – Joint Implementation

Klif – Climate and Pollution Agency

kV – Kilovolts

KWh – Kilowatt hour

LNG – Liquefied Natural Gas

MC – Marginal Cost

MCA – Marginal Cost of Abatement

MCS – Marginal Social Cost

MEC – Marginal External Cost

MPE/OED – Ministry of Petroleum and Energy

MWh – Megawatt hour

NCS – Norwegian Continental Shelf

NGL – Natural Gas Liquids

NOK – Norwegian Kroner

NOU – Norwegian Official Reports

NO_X - Nitrogen Oxides

NPD – Norwegian Petroleum Directorate

NPRA – Norwegian Public Roads Administration

NPV – Net Present Value

NVE – Norwegian Water Resources and Energy Directorate

OECD - Organization for Economic Cooperation and Development

OED – Ministry of Petroleum and Energy

OPEC – Organization of the Petroleum Exporting Countries

OPEX – Operational Expenditure

PDO – Plan for Development and Operations

PFS – Power from shore

ppm – Parts Per Million

RFT – Request for Tender

Sm^3 – Standard Cubic Meter

SSB – Statistics Norway

TWh – Terawatt hour

UN – United Nations

UNCED - United Nations Conference on Environment and Development

UNFCCC - United Nations Framework Convention on Climate Change

WACC – Weighted Average Cost of Capital

WHRU – Waste Heat Recovery Unit

WMO - World Meteorological Organization

ZERO - Zero Emission Resource Organisation

8. Appendix

8.1 Annex countries

Parties to the UNFCCC are classified as:

- **Annex I**: Parties to the UNFCCC listed in Annex I of the Convention. These are the industrialized (developed) countries and "economies in transition" (EITs). EITs are the former centrally planned (Soviet) economies of Russia and Eastern Europe. The European Union-15 (EU-15) is also an Annex I Party (UNFCCC, 2011)
- **Annex II**: Parties to the UNFCCC listed in Annex II of the Convention. Annex II Parties are made up of members of the Organization for Economic Cooperation and Development (OECD). Annex II Parties are required to provide financial and technical support to the EITs and developing countries to assist them in reducing their greenhouse gas emissions and manage the impacts of climate change (UNFCCC, 2011)
- **Annex B**: Parties listed in Annex B of the Kyoto Protocol are Annex I Parties with first- or second round Kyoto greenhouse gas emissions targets. The first round targets apply over the years 2008-2012. As part of the 2012 Doha climate change talks, an amendment to Annex B was agreed upon containing with a list of Annex I Parties who have second-round Kyoto targets, which apply from 2013-2020 (UNFCCC, 2012). The amendments have not entered into force.
- **Non-Annex I**: Parties to the UNFCCC not listed in Annex I of the Convention are mostly developing countries. Developing countries may volunteer to become Annex I countries when they are sufficiently developed (UNFCCC, 2011).

8.2 Transport

Table 2.4 shows that road traffic emitted 10.1 million ton CO_2 in 2011 which is a 29.5% increase from 1990. Figure 8.1 gives a basic illustration of which factors that drove emissions in the Norwegian transport sector[46].

[46] The numbers are from 2007

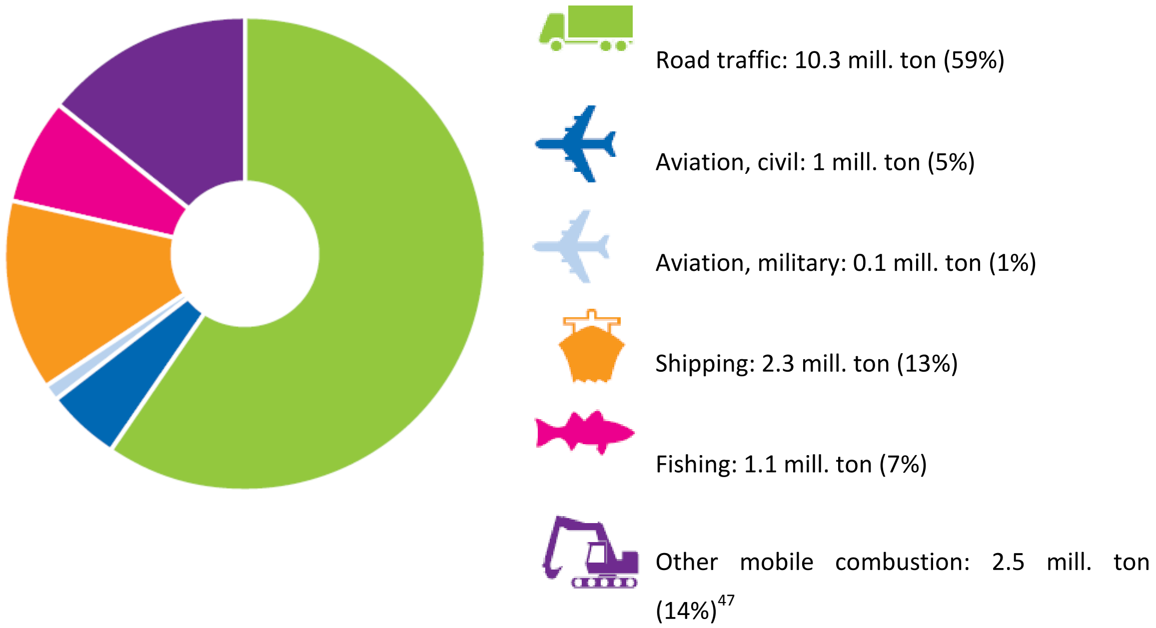

Figure 8.1 Source: Climate Cure 2020, 2010

Road traffic (59%), shipping (13%) and other mobile combustion sources (14%) account for over 80% of the emissions from the transport industry. Aviation, shipping and fishing emitted a total of 7.3 million ton CO_2 in 2011 which is up 29.4% from 1990. The transport industry is complex and consists of many participants with different needs. The sector spans from short distance commuting to long distance cargo trains (Climate Cure 2020, 2010).

Towards 2020, Climate Cure 2020 (2010) estimates that it is possible to reduce CO_2-emissions from the transport industry with 3-4.5 million tons CO_2. This reduction is dependent on strong measures and large investments through great political will and action. The largest emission reductions is expected to be found in biofuels and vehicle technology, which at most can contribute with a total reduction around 2.6-2.7 million tons. Further estimates show a potential reduction of 1.2-1.4 million tons CO_2-equivalents from development in public transport and higher fees on car and airline transport. The demand for transport services increases with economic and population growth. Without implementation of measures, we can expect an increase from today's level of 17 million tons CO_2 to around 19 million tons in 2020 and 21 million tons in 2030. The projections towards 2020 and 2030 from Climate Cure (2010) has also accounted for somewhat significant emission reductions caused by technology improvements. Norway has already taken

[47] *Other mobile combustion* does mainly consist of railway and combustion from motorized equipment such as tractors and excavators.

measures to reduce emissions in the transport sector by for example introducing a CO_2-fee on fuel. Because several measures already have been implemented, Climate Cure suggests that it might be costly to reach the emission targets for the transport industry in Norway compared to other countries.

8.3 Industry

Table 2.4 shows that the total emissions from the industry- and mining sector[48] was 11.8 million ton in 2011 which is nearly 40% less than in 1990. The emissions arise from different industries such as pulp and paper, chemical industries, mineral industry, metal production and other industries (food- and engineering industries).

In 2007 the Norwegian onshore industry had energy consumption of around 80 TWh, which was one third of the country's total energy consumption. Norwegian industry is highly energy intensive compared to the industry sector in other countries. 82% of the energy consumption in the industry sector is due to energy intensive industries such as aluminum production, ferroalloy industries, pulp and paper and chemical industries. Since the Norwegian electricity supply is mainly based on hydropower, the industry sector does not represent a correspondingly large fraction of the national GHG emissions[49].

The emission reductions that we have experienced since 1990 is mainly caused by a few following factors:

- Sulfur hexafluoride (SF_6) emissions from magnesium production, accounting for 2.1 million ton CO_2-equivalents has ceased due to closures.
- Perfluorocarbons (PFCs) emissions from the aluminum industry have been reduced from 3.4 million ton CO_2-equivalents in 1990 to 0.2 million ton CO_2-equivalents in 2007. This reduction has mainly been caused by a shift from Søderberg technology to a prebake technology as well as process improvements.
- Nitrous oxide (N_2O) emissions from the fertilizer industry has been reduced with about 1.3 million ton as a consequence of newly developed catalyst technology that was taken into use in all Norwegian process lines during the period from 2007-2010.

[48] Referred to as the industry sector
[49] From table 2.4, the industry sector represent around one fifth of the GHG emissions.

- CO_2 emissions from the Ferroalloy industry have been reduced with around 1 million ton since year 2000 due to closures and production changes. Production changes are mainly capacity reductions and establishment of new processes based on the same production equipment.

8.4 Climate Cure 2020 industry sector emission projections

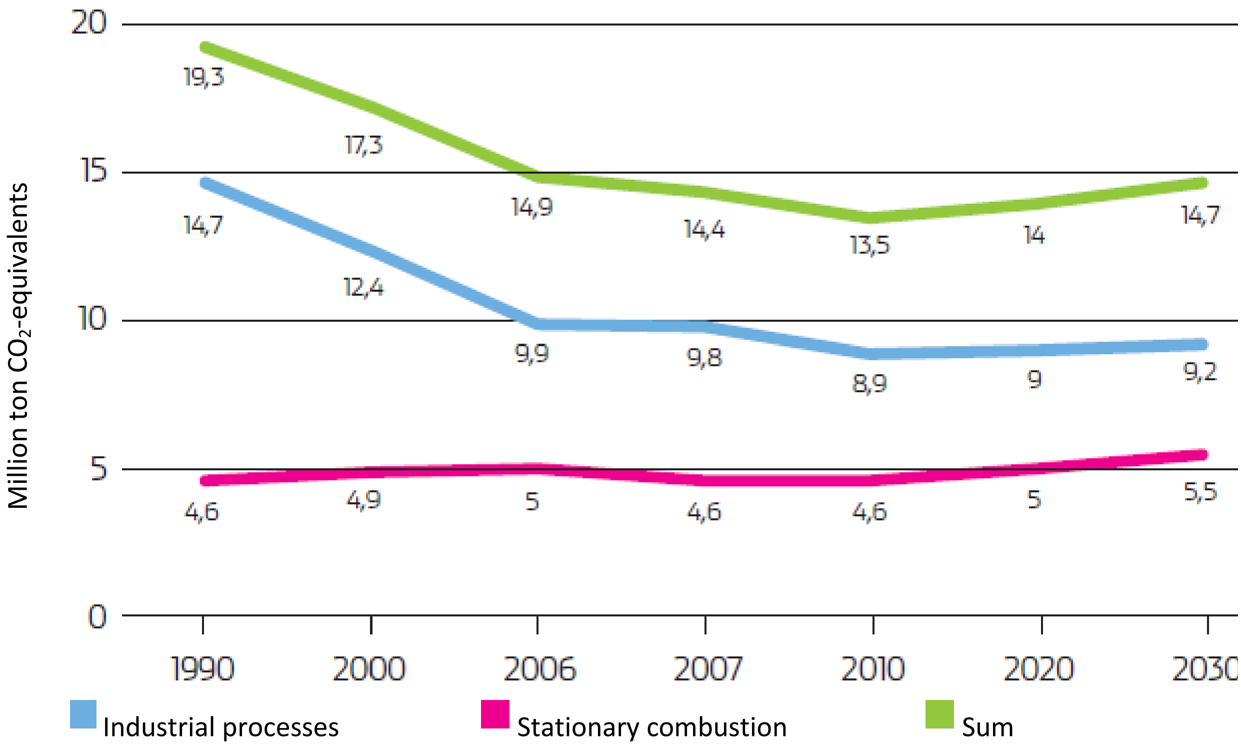

Figure 8.2 - Projections towards 2010, 2020 and 2030. The figure also shows emission development from 1990 to 2007. Notice that the intervals on the time-axis vary. Source: Climate Cure 2020, page 129

8.5 Abatement Cost overview in the petroleum industry

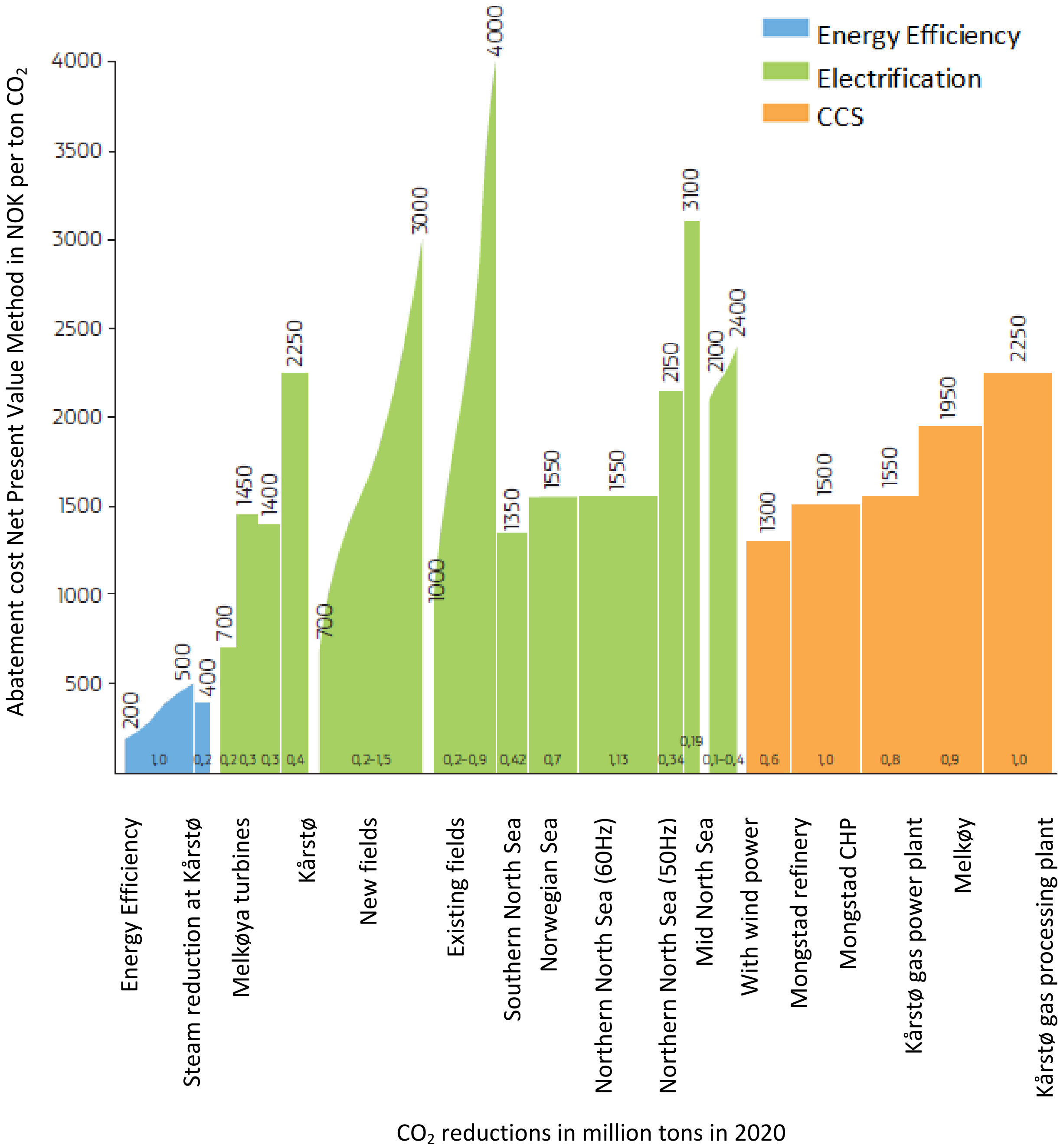

Figure 8.3 - Abatement Cost for measures in the petroleum industry,
Source: Climate Cure 2020 page 121

8.6 Time estimates for electrification projects on Utsira High

Edvard Grieg	
Activity	**Time period**
Suggested assessment program	17.06.2010
Consultation of assessment program	17.06.2010-17.09.2010
Adjusting for comments	September - December 2010
Completion of the assessment program	28.01.2011
Impact study	August 2010 - September 2011
Cosultation of KU	September - November 2011
Submitting PUD	December 2011
Planned construction period	Q2 2014 - Q3 2015
Planned production start	October 2015

Table 8.1 Edvard Grieg development plan
Source:Plan for utbygging, anlegg og drift av Luno, del 2 konsekvensutredning

Dagny and Eirin	
Activity	**Time period**
Investment decision Dagny	December 2012
Investment decision Eirin	June 2013
Allocation of main contracts	January 2013
Installation Dagny, rig and pipes	Summer 2015
Installation bottom frame Eirin	Summer 2015
Pre drilling start	Sep.15
Installation main deck Dagny	June 2016
Tie-in-activities	Summer 2016
Planned production start	December 2016

Table 8.2 Dagny & Eirin development plan
Source: Plan for utbygging, anlegg og drift av Dagny og Eirin, del 2 Konsekvensutredning

Ivar Aasen	
Activity	**Time period**
Installation of platform substructure	Q2 2015
Pre drilling avtivities	Q3 2015
Installation of platform deck	Q2 2016
Production start	Q4 2016
Production shutdown and dismantling	2028

Table 8.3 Ivar Aasen development plan
Source: Plan for utbygging og drift av Ivar Aasen, del 2 konsekvensutredning

8.7 Calculating the annuity factor for the investment cost

$$(1) I = a\left[\frac{1}{1+r} + \frac{1}{(1+r)^2} + \cdots + \frac{1}{(1+r)^T}\right] = aS$$

$$(2)\ S = \frac{\frac{1}{1+r} - \frac{1}{(1+r)^{T+1}}}{1 - \frac{1}{1+r}} = \frac{1 - \frac{1}{(1+r)^T}}{r}$$

$$(3)\ a = \frac{Ir}{1 - \frac{1}{(1+r)^T}}$$

8.8 Executive summaries from precious field reports on PFS projects

8.8.1 Kraft Fra Land til Norsk Sokkel/Power from shore to The Norwegian Continental Shelf, (NPD, 2008)

Calculations estimate that the abatement cost tied to the electrification process of existing installations on the shelf will start at 1600 NOK per ton CO_2 and rise. The high abatement cost is mainly caused by the level of CAPEX, the complexity of the project and the lifetime of the fields. Development in technology could in the future enable more installations for electrification and increase the utilization level of the offshore transmission infrastructure. The report is based on the three following scenarios for power production:

1. Dedicated power production
2. Power from the market – physical effects
3. Power from the market – with emission commitments and ETS

8.8.2 Strøm fra land til olje- og gassplattformer/Power from shore to oil and gas platforms, (Zero, 2011)

The Zero report has calculated the potential for CO_2 abatement from power from shore solutions tied to offshore installations. It is possible to reduce between 3 and 7 million tons of CO_2 depending on ambitions. Zero reports that the bottom estimate will demand 771 MW power to the offshore installations.

The balance in the power market is emphasized and to avoid a situation like the Ormen Lange construction there must be a high focus on the power transmission lines from Modalen to Mongstad to Kollsnes to be able to supply energy to the northern North Sea. Zero does also list a wide range of direct measures the government must implement to ensure that power from shore will be the chosen solution from the operators. Zero presents the three following solution packages:

1. High ambition level, reduces emissions with 7.4 million tons of CO_2 annually. This includes full electrification of all field mentioned in the report

2. Medium ambition level will reduce 4.1 million tons of CO_2 annually. This includes full electrification of the Ekofisk area and part-electrification of the mid North Sea fields, The Norwegian Sea and full electrification of Oseberg, Troll, Kvitebjørn and Gullfaks in the northern North Sea.

8.8.3 Elektrifisering av sokkelen/Electrification of the shelf – A case study of the southern North Sea and the Oseberg area, (Bellona, 2007)

The main outline for the Bellona report is the demand for a new electrification report from the government since the claim the 2002 power from shore report from NPD and NVE is outdated. The report strongly doubt that Norway will be able to fulfill their Gothenburg commitments if the government allows the operators to choose between buying quotas or install power from shore, especially having in mind the NO_x-reductions.

Having in mind that it is possible to buy CO_2-quotas we know that NO_x-reductions have to be taken on a national level. Without the electrification which strengthen the NO_x-reductions it is a risk that the NO_x-fees have to be raised to such a high level that the potential cost will jeopardize the existence of many other sectors for example the marine sector. Bellona does not claim to be 100% correct but do strongly disagree with the 2002 calculations the estimates an abatement cost equal to 981 NOK per ton of CO_2. The report take a wide range of what they refer to be conservative adjustments building their calculations on the 2002 report from NPD and NVE, the result is a new abatement cost equal to 206 NOK per ton CO_2. The report seriously doubt any measures to be taken from the operators and therefore recommend the government with Statkraft and Statnett to construct subsea transmission lines that must be used by the offshore installations.

8.8.4 Power from shore to the Ekofisk area, (ConocoPhillips, 2012)

PDO were approved in June 2011 for both Eldfisk II and Ekofisk South. As a part of the impact assessment emission reduction options, electrification and partial electrifications of the Ekofisk area fields were evaluated. Partial electrification which is the most viable solution showed negative Net Present Value (NPV) for all of the evaluated scenarios, and an abatement cost which was no lower than 2376 NOK per ton (discounted at 10% after tax). As a result none of the options were deemed economic and therefore were not recommended. The main conclusions from the report are stated below:

- All studied cases has negative NPV at 10%, 5% and at 7% discount rate. Abatement Costs between NOK 1499 and 6656 per ton (10% after tax and for full field life). Partial electrification can therefore not be justified on economic merits.

- Economic merits within the 2028 license period result in a higher Abatement Cost and lower NPV than shown above.

- The Ula field and possibly Tor redevelopment may require a power solution in place as early as in 2017. For an electrification project to succeed, timely onshore regulatory approvals and early commitments in a tight market for cable procurement and cable installations vessels would be required.

8.8.5 Elektrifiseringsvurderinger av området midtre Nordsjø/ Electrification evaluation of the mid North Sea area, (NPD, 2012)

The report has been conducted as an area specific evaluation of power from shore solutions for several fields in the mid North Sea area, including also one future undiscovered field. With a given set of assumptions the abatement cost has been calculated. To test the robustness of the report sensitivity analysis as measured the impact of changes in central factors.

The study find an abatement cost equal to 412 NOK per ton CO_2, which is higher than the sum of today's CO_2-fee and price of EU ETS allowances, but lower than the CO_2-cost suggested in the climate report. The sensitivity analysis shows that the project is vulnerable to investment cost, future energy demand and price differences between natural gas sold on the continent and electrical power from the Norwegian grid.

8.8.6 Utsira High Power Hub report from project group to the Ministry of Petroleum and Energy (Statoil, 2012)

This Utsira High study was initiated by the ministry of Petroleum and Energy after the recent discovery of the Johan Sverdrup field, the project is led by Statoil together without the other licensees. The main aspect of the study is to develop a framework for power from shore for choice of concept and investment decision. The power demand at the four fields is estimated to be somewhere between 250-300 MW. The report states that Johan Sverdrup which has the largest power demand has a planned startup in 2018 and in such an early phase of the project it is hard to predict the future power demand.

The abatement cost for the project is currently estimated to lie between 300-600 NOK/ton CO_2. With high uncertainty to many assumptions the analysis shows that the project is especially sensitive to changes in investment costs and development in gas and electricity prices. The participating companies has conducted net present value calculations that returns negative results, showing that it is of high importance to develop a good technical concept where the investment cost can be reduced.