Master's degree thesis

LOG953 Petroleum Logistics

Economic appraisal of carbon impacts of gas infrastructure development in the Barents Sea

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Number of pages including this page: 81

Molde, 24.05.2019

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Preface

This thesis represents the mandatory final part of our Master of Science Degree in Petroleum Logistics at Molde University College. A research proposal was presented and defended in December 2018 and built the basis for this thesis. The work was written from January through May 2019. We would like to express our gratitude first and foremost to our supervisor Katerina Shaton for her excellent guidance during the process of writing this thesis. Furthermore, we thank our families for their support – without their support we would not be where we are now. Their love and belief in us give us inspiration. Special thanks go to our professors from Gubkin Russian State University of Oil and Gas.

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Molde, May 2019

Vladislav Zamiatkin & Angelina Angelova

Abstract

The Norwegian petroleum industry demonstrated a rapid growth during the last decades. A successful development of oil & gas fields in the North Sea made it possible to extend the exploration to the north of the Norwegian continental shelf (NCS). Currently, the north part of the NCS, especially the Barents Sea region is characterized by the lack of gas transport infrastructure. Therefore, in order to provide the successful exploration of the north part of NCS, the establishment of transport solution is needed.

Currently the economic appraisal of new infrastructure development projects in petroleum sector does not include the estimation of environmental externalities such as emissions of greenhouse gases due to implementation of these projects. Nevertheless, the environmental impacts which occur during either construction and operation of gas transport facilities may lead to harmful consequences for the society. One of the most significant impacts due to the development of a new gas infrastructure is the carbon footprint.

The purpose of this research is to consider several possible alternatives for the establishment of gas transport solution in the Barents Sea region distinguished by the different sources of power supply and to identify which of these alternatives is more preferable from the environmental perspective. Based on the available data on unit emissions associated with different sources of power generation, we appraise the annual emissions for each of the considered scenarios. In order to put the environmental considerations in the socio-economic framework, we estimate the value of environmental externalities of infrastructure projects according to their social costs.

CONTENTS

1. INTRODUCTION

At present, increasing attention of scientists and policy makers all over the world is directed to the carbon emissions and the associated climate change. The main sources of emissions are electricity generation sector, petroleum industry and iron industry. As negative effects of climate change impose costs on society, these costs should be internalized in the economic appraisal of public projects. The main question for public policy is how to include impacts of carbon emissions in the analysis and which cost to assign for these impacts.

Today, many countries implement environmental policies aiming to reduce carbon emissions. It makes natural gas an attractive transition fuel to the “green” economy. Norway contributes substantially to the European gas market, covering about 25% of the European gas demand (Norskpetroleum 2018c). In 2017, Norwegian gas sector set a record for gas deliveries from the Norwegian continental shelf (NCS) by transporting more than 117 billion standard cubic meters (scm) of natural gas via pipeline network to Europe. (Gassco Annual Report 2017).

One of the distinctive features of the Norwegian petroleum industry is the offshore location of the resources on the Norwegian continental shelf (NCS). The petroleum activities started in North Sea with the discovery of Ekofisk in 1969. A successful development of oil & gas fields in the North Sea made it possible to extend the exploration to the Norwegian Sea and the Barents Sea. As the existing fields get depleted, development of new fields is needed to maintain the sustainable performance of the petroleum industry in the long run. It should be emphasized that about 2/3 of expected natural gas resources in Norway are still not produced (Norskpetroleum 2018c).

The most promising area to expand the oil & gas activities is the north of the NCS. According to the NPD, about a half of the overall undiscovered resources on the NCS is located in the Barents Sea. Unlike the Norwegian Sea and the North Sea, the Barents Sea is characterized by the lack of transport infrastructure (Norskpetroleum 2018a). Currently there exist only one facility which receives natural gas from the gas field in the Barents Sea. Melkøya LNG is the final point of the pipeline which transports natural gas from the Snøhvit gas field in the Barents Sea.

A relevant question is which transport solution should be established to provide sufficient development of gas production and exploration in the Barents Sea. Gassco (2014) considered two possible alternatives for the establishment of gas transport infrastructure in the Barents Sea: the expansion of the existing LNG facility at Melkøya and a 42-inch pipeline. However, the final decision has not been made yet.

1.1 Research Objectives

The implementation of gas transportation infrastructure projects usually entails a range of externalities. The externalities may incur both positive and negative impacts on the third parties. The environmental consequences of gas infrastructure projects such as air or water pollution cause negative impacts on society and thus refer to negative externalities. The existing practice of the economic appraisal of gas infrastructure development projects does not include the assessment of external effects.

Our thesis is based on the framework established by Shaton (2017) where she investigated how the methodology of Cost-Benefit Analysis (CBA) can be implemented for the economic appraisal of the gas infrastructure development projects. Using this method, she appraised value of the environmental externality of the chosen solution for the Polarled pipeline project in the Norwegian Sea. In our research, we will calculate the value of environmental externalities of the alternative solutions for the Barents Sea gas infrastructure project. The main contribution of this thesis is to evaluate carbon footprints (and the associated social costs) of the gas transportation alternatives taking into consideration different power supply options, including the import of electricity.

Therefore, the overall aim of this research is to determine the value of externalities related to carbon emissions of implementation of the potential gas transport solutions in the Barents Sea with regard to the power supply options. With the aim to attain research objectives, we outline the following research steps:

1. Calculate the CO_2 emissions from the potential gas transport solutions in the Barents Sea. The existing literature does not estimate emissions from gas transport alternatives depending on the sources of electricity generation. However, emissions per unit of value vary considerably depending on the sources of electricity generation. While 0.37 tons of CO_2 is generated for the production of 1 MW of electricity from coal combustion, the production of electricity from the hydropower plant entails CO_2 emissions equal to 0.006 tons. Thus, the total emissions from the potential gas transport solution depend directly on the source of electricity supply. In our thesis, we will estimate the total emissions from potential gas transportation solutions which are: power supplied by nuclear, coal hydroelectric power plants and gas generators.

2. Explore different current carbon policies and define appropriate value carbon price to estimate value of externalities of carbon emission due to the implementation of gas infrastructure projects. To accomplish this step, we will consider various carbon policies both in Norway and in the world. Also, for a more correct definition of appropriate value of carbon price, the world experience for such kind of calculations will be analyzed.

3. Put a carbon price on CO_2 emissions for all scenarios and calculate the total emissions for each of the gas transport options. Gathering all results from this step we will put the price on the emissions from the hypothetical value chain scenarios. Then, we will find the cost of externality by subtracting the taxes that the companies pay.

4. Investigate the impact of carbon pricing on the future Norwegian gas infrastructure projects.

1.2 Structure of the thesis

This thesis comprises seven main chapters with respect to the research objectives. The first part of the project outlines the overview of the problem and specify the research objectives. The second chapter devoted to the description of the operation of the organizational framework of the gas transport infrastructure in Norway. Chapter 3 presents the review of the theoretical framework which is used for the analysis. Chapter 4 describes the potential gas transport solutions which may be established in the Barents Sea region. Chapter 5 considers the alternative sources of electricity for chosen transportation chains. In chapters 6 and 7, we present the results and the sensitivity analysis, provide discussion and give recommendations.

1.3 Classification of data

One can distinguish two types of data: primary data and secondary data. Primary data is collected by the researcher himself using the interviews, experiments, surveys, etc. Secondary data is the type of data which was collected by someone else. In comparison with the primary data, secondary data can be characterized as readily available. There are several types of secondary data. Among them are statistical information from authorities and independent international agencies, companies' annual reports, etc. (Yin 2009).

In our research we will mostly use secondary data, which includes the following:

- Publicly available appraisal documents (e.g. PDO of Snøhvit gas field, PIO for Hammerfest LNG);
- Official reports from the Norwegian Ministry of Petroleum and Energy (e.g. Proposition to the Parliament - Prop. 97 S (2012–2013));
- Information from the official statistic sources such as Statistics Norway, NPD, EEA;
- Academic papers (e.g. Vickerman 2007, Fidler 2012);
- Textbooks (Boardman 2011, Campbell 2003, Abbott 2017).

2 GAS TRANSPORT INFRASTRUCTURE

The goal of this chapter is to describe natural gas value chain. This chapter also explains how the Norwegian gas transport sector is organized and how the main parties involved in the operation. Outcomes of this chapter contribute to the research in the following chapters.

2.1 Natural gas value chain

Generally, value chain for natural gas consists of four main stages: production, processing, transportation and distribution. These stages have a variety of developed systems for the delivery of hydrocarbons from their offshore production to coastal destinations. The transport infrastructure includes not only the tanker fleet and seabed pipelines, but also marine transshipment facilities, onshore storage terminals, liquefaction and regasification plants, auxiliary vessels, berthing facilities, land pipelines and other necessary technical facilities.

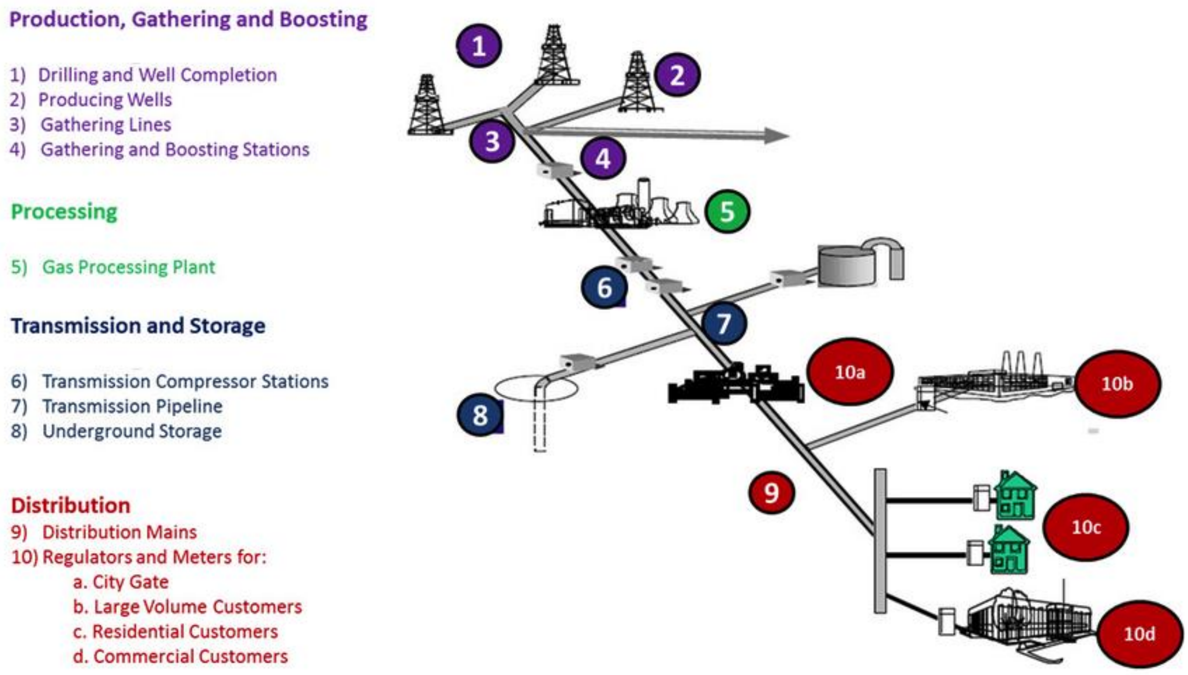

Figure 2-1: Organization of the natural gas supply chain (Source: adapted from EPA 2013)

- **Preparation of natural gas for transportation**

The gas coming from the wells must be prepared for transportation to the end user — chemical plant, boiler house, thermal power plant or urban gas networks. For the present, the total length of the gas distribution network is several times greater than the circumference of the globe.

Before transporting, the extracted gas goes through a certain preparation. The preparatory stage is very significant, because the newly produced gas from the well has a variety of impurities, which can subsequently cause damage to the equipment. One of the main stages is gas dehydration. This process is necessary for elimination of moisture. Moreover, carbon dioxide and hydrogen sulfide must be removed before the gas can be transported via a pipeline. The gas-purifying takes place in several stages: immediately after production, then in specialized separators and before transportation at special compression stations.

- **Natural gas transportation**

Gas transportation system is a set of interconnected gas pipelines and related facilities designed to provide gas to consumers. The structure of the gas transportation system comprises: main gas pipelines, distribution gas pipelines, gas pipelines-jumpers, taps, etc.

As the energy density of natural gas is lower than the density of other source of energy like oil or coal, the transportation of natural gas is more difficult. A low temperature or high pressure is required to increase the density of the natural gas and energy content per unit volume.

For the present, the main mode of gas transportation is pipeline. Gas under pressure of 75 atmospheres moves through pipes up to 1.4 meters in diameter. Offshore pipelines are constructed and operated in severe condition. In addition to the pressure of the transported gas undersea pipelines are operated under external hydrostatic water pressure. They can also be affected by waves and stream course.

Depending on the purpose, there are 3 types of offshore pipelines:

1) infield pipelines are designed to connect wells with different objective intervals through one field.

2) gathering gas pipelines are designed for technological connection of oil rigs and other objectives in surrounding fields.
3) main gas pipelines or distribution pipeline system are laid for gas supply from the field to points of transshipment or final delivery.

- **LNG**

The industry experts consider the 1964 year as the birth of the industry, when the first contract for the supply of LNG from Algeria to the UK and France was signed. Over 50 years, annual sales of LNG increased 110 times: from 3 billion to about 331 billion cubic meters. Natural gas provides about a quarter of the world's energy consumption, 10% of which belongs to LNG. The LNG industry is growing relatively fast in energy sector – its capacity is increasing by about 7% per year (IGUa,2015). According to forecasts of the International energy Agency (IEA, 2018), by 2030, the LNG sector will be the driving force of globalization of the gas industry. For example, while the volume of natural gas pipeline supplies has increased by 45% over the past 10 years, LNG sales have more than doubled (IEA, 2018).

The main LNG exporters are depicted in the figure 4-2. The leader is still Qatar, which occupies about a third of the market. Sufficiently large LNG capacities are located in Malaysia, Australia, Nigeria, Indonesia, Trinidad and Tobago, Algeria, Russia and Norway.

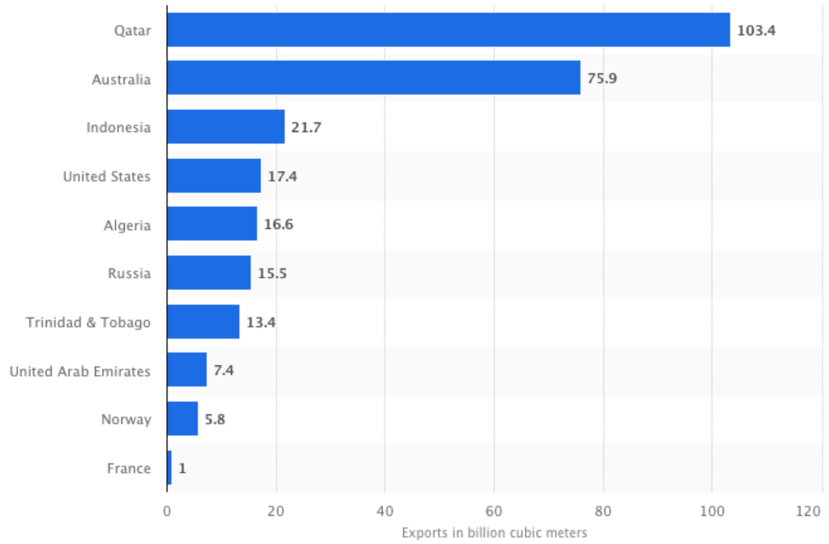

Figure 2-2: Major liquefied natural gas exporting countries in 2017 (in billion cubic meters)

(Source: BP Statistical Review, 2018)

- **The life cycle of LNG**

The life cycle of LNG starts from the moment natural gas flows to the liquefaction plant. The LNG plant prepares and liquefies the gas, after which the LNG is supplied to special storage tanks. LNG is shipped to gas tankers. The tankers are then delivered to LNG receiving terminals, which are equipped with storage tanks and regasification facilities. At these facilities, LNG is converted into a gaseous state and delivered to consumers. LNG can also be delivered to consumers in a liquefied state in tankers, tank containers or tank wagons by rail. Schematically, the life cycle of LNG is shown in figure 4-3. The life cycle of LNG is presented here for large-scale industries, from which LNG is supplied by sea by large-capacity tankers (the most capacious method of transportation of cryogenic cargo).

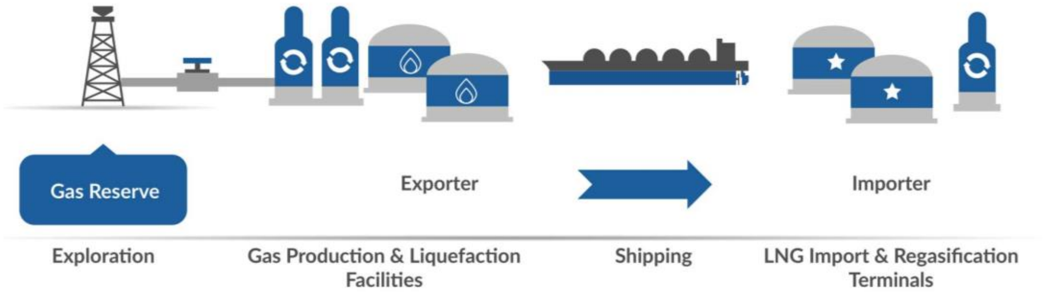

Figure 2-3: The life cycle of LNG. (Source: IGUb)

In comparison with the preparation of natural gas intended for transportation by the gas pipeline, gas purification for subsequent liquefaction is carried out more carefully. This is necessary to prevent freezing of related impurities, damage and clogging of refrigeration equipment in the cryogenic sections of the plant.

- **Maritime transport of LNG**

The LNG is pumped from the storage tanks into the loading lines leading to the LNG shipment berth, which is equipped with sleeves shipping. At the head of the berth, the pipelines are connected to the berth sleeves, and those, in turn, to the cargo tanks of gas carriers. The duration of loading operations varies from 6 to 16 hours depending on the cargo capacity of the vessel. LNG is unloaded at the receiving terminals with using a network of pipelines to storage tanks and regasification plants.

In gasification plants, a controlled process of LNG evaporation takes place, and then natural gas is sent to distributors and end users through pipelines. If consumers need LNG, it is reloaded into tankers or tank wagons and transported by road or railroad.

- **LNG vs Pipeline**

As the geography of offshore hydrocarbon production and development expanded, oil and gas transportation systems were formed both by pipelines on the seabed and by special tanker fleet. Each of these methods has its advantages and disadvantages depending on the specific combination of many factors and circumstances in different regions. The advantages and disadvantages of pipeline and LNG transportations are presented at the table.

Table 2-1: Pipeline vs LNG (Source: Vyakhirev, Nikitin, and Mirozev (2001))

Seabed pipeline		**LNG**	
Pros	**Cons**	**Pros**	**Cons**
High reliability, all-weather and season capability	The inability to change the flow direction	Ability to change quickly the volume of the supply	Exposure to natural and climatic conditions
Shorter distance for transportation (straight line)	Large capital cost	Ability to transport simultaneously in several directions	Intermittent of hydrocarbon delivery
continuous supply	Long period for construction seabed pipelines	Ability to change quickly the direction of the supply	High ecological risks
Low hydrocarbon leakage during transportation	the inability to increase delivery destinations	No maximum distance restrictions	Necessity to build liquefaction and regasification plants
Low ecological risks	the inability to increase the volume of transported products	Ability to transport in severe arctic conditions	Necessity to build oil export and import terminal
Low operation costs	Limited maximum transport distance	Unbounded capacity of waterways	Marine-based pollution
high delivery speed	The inability to use pipeline in icy waters	reduction of Operating costs by increasing the length of transportation	High operation cost

2.2 Organizational framework of the petroleum activities in Norway

The framework of state organization of the petroleum activities in Norway is represented in the Figure 2-4. The Storting (Norwegian Parliament) is in charge of the legislative process related to the petroleum industry in Norway. The Storting is responsible for decision making over the major development projects, approval of the development of new fields and, additionally, it coordinates the Government and public administration (MPE 2014).

The Government represents the executive authority regarding the issues related to petroleum policy. Multiple ministries, directorates and supervisory authorities are involved into executive activities under the control of the Government. The respective responsibilities of each of the parties involved are described in detail below.

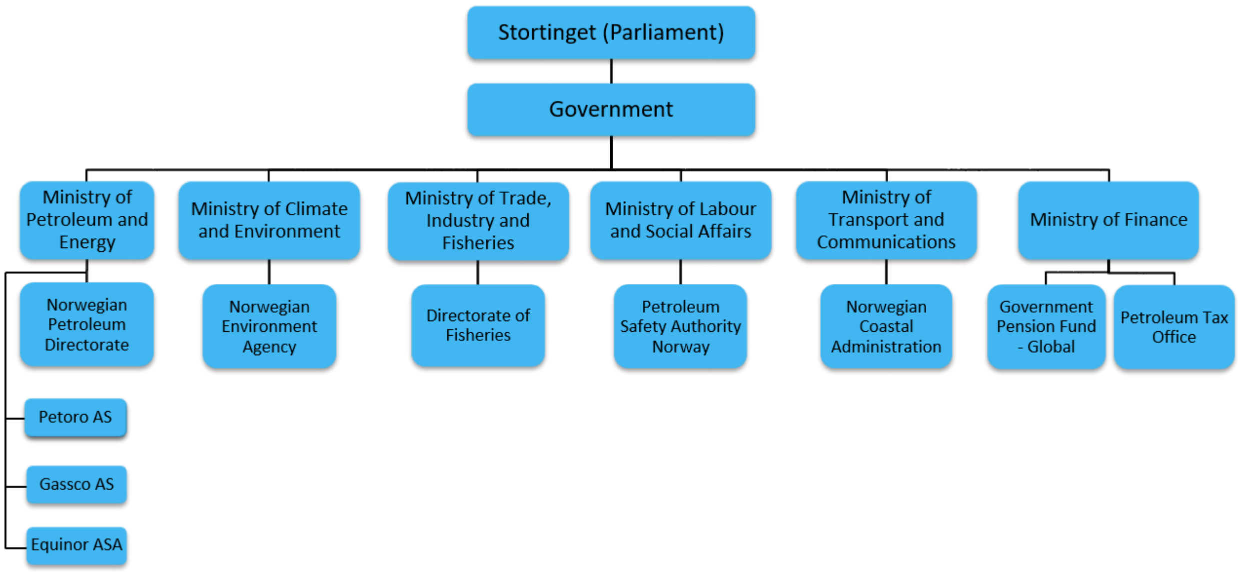

Figure 2-4 State organization of petroleum activities (Source: Norwegian Petroleum Directorate)

The Ministry of Petroleum and Energy (MPE) is responsible for both resource management and the whole oil and gas industry. The subordinate of the MPE, Norwegian Petroleum Directorate (NPD), carries out activities related to the professional expertise of the petroleum activities and is responsible for the review and analysis of data from the Norwegian continental shelf. The Ministry of Climate and Environment in cooperation with its subordinate authority Norwegian Environmental Agency is responsible for taking measures over environmental protection and the external environment in Norway in accordance with Pollution Control Act (Act of 13 March 1981 No.6 Concerning Protection Against Pollution and Concerning Waste). The Ministry of Finance has the responsibility for State's revenues from the petroleum sector. It has two subordinate bodies: Government Pension Fund – Global and the Petroleum Tax Office. The purpose of the Government Pension Fund – Global is to facilitate government savings to finance rising public pension expenditures. The core responsibility of the Petroleum Tax Office is to provide proper stipulation and payment of taxes and fees appointed by the Government.

Further, we would like to discuss three cornerstones on which the operation of the gas transport infrastructure in Norway is based on: ownership, operatorship and regulation.

2.2.1 Ownership

In 2001, in order to facilitate the management and to improve the operation of the gas transport system the MPE decided to consolidate all the companies which owned separate pipelines into one enterprise called Gassled. The Gassled ownership agreement came in force in January 2003. A total of 11 companies had participating interests in Gassled. This partnership serves as the formal owner of the majority of the Norwegian gas transport infrastructure (Gassco 2014). Currently Gassled partnership comprises the following enterprises: Petoro AS, Solveig Gas Norway AS, CapeOmega, Silex Gas Norway AS, Infragas Norge AS, Equinor AS. The respective shares of each of the companies in Gassled partnership is represented in Table 2-2.

Table 2-2 Gassled's owners (Source: Gassco, 2019)

Petoro AS*	46.697 %
Solveig Gas Norway AS	25.553 %
CapeOmega	11.316 %
Silex Gas Norway AS	6.428 %
Infragas Norge AS	5.006 %
Equinor AS	5.000 %

Gassled has rights of ownership for pipelines, terminals and rich and dry gas facilities on the NCS. By now Gassled comprises the following pipelines: Aasgard Transport, Norne Gas Transport System, Statpipe, Europipe I, Europipe II, Zeepipe, Franpipe, Oseberg Gas Transport, Vesterled, Norpipe, Langeled and Kvitebjoern. It also includes gas treatment complex at Kårstø, three receiving terminals at Emden in Germany and one at St. Fergus in the United Kingdom, Zeebrugge in Belgium, Dunkerque in France and Kollsnes gas processing plant (www.gassco.no).

2.2.2 Operatorship

In 2001 the Norwegian Government established the state-owned company Gassco AS. On 1 December 2002 Gassco AS took over the operatorship of all gas transport from the NCS and started operating as an independent system operator for Gassled. Gassco does not gain revenues or bear costs from its operations. Gassco holds its operator responsibilities in accordance with both Norwegian Petroleum Activities Act and agreements with owners of gas transport infrastructure.

The work of Gassco as an operator can be considered from two points of view. The activities which is conducted by Gassco AS on behalf owners of infrastructure is titled the **normal operatorship**. Under the normal operatorship we understand technical maintenance of plants and facilities in accordance with The Norwegian Petroleum Act and the operator agreements with infrastructure owners. The activities which are connected with system operation and capacity administration are designated as **special operatorship**. Such activities are performed for all users of integrated gas transport system and regulated in accordance with the Petroleum Activities Act. Special operatorship includes the following: development of the existent gas transport system, capacity management in the infrastructure and system operation.

2.2.3 Regulation

The administration of the petroleum industry in Norway is performed through the comprehensive legislation. It implies that petroleum companies are obligated to obtain licenses for the implementation of the petroleum activities on the NCS. The most important regulating document is the Petroleum Act (Act of 29 November 1996 No. 72). This document contains the regulation standards for resource management such as licensing system, companies' rights and responsibilities. Regulations related to the development of the new infrastructure are described in chapter 4 of this Act. Section 4-3 specifies that to obtain a license for installation and operation of such facilities as pipelines, liquefaction facilities and other facilities for transportation or utilization of petroleum, the company should submit an application to the government which contains the plan for the construction and operation of the facility.

Another important regulating document is Regulations to Act relating to petroleum activities (27 June 1997 pursuant to Act 29 November 1996 no 72 relating to petroleum activities). The development of the new infrastructure is regulated pursuant to chapter 4 of the Regulations. This document provides detailed legal regulations concerning petroleum activities.

2.3 Interactions between parties involved in gas infrastructure development

There are three main parties involved in gas infrastructure development in Norway. Among them are commercial companies (Gassled joint venture), the state-owned company Gassco AS (the system operator) and the Norwegian Government. Commercial companies assume the role of investor and infrastructure owner. Gassco AS contributes to the gas infrastructure development by estimating the new infrastructure projects from the value creation perspective in the long term. The Norwegian Government is assumed as a public regulator by granting licenses for the extraction of petroleum and by imposing regulated tariffs (Shaton, 2017). Commercial companies pursue the interests of profit maximization while the government is striving to enhance the level of social welfare.

The infrastructure planning process may be triggered by both petroleum companies which possess licenses for petroleum activities on the NCS and the system operator Gassco AS which conducts the annual assessment of the necessity for the extra capacity. In case of the need for a new gas infrastructure the concept selection process begins. The chosen concept should fulfill the interests of investors (Gassled joint venture), petroleum companies which are in need for a new infrastructure and also the system operator. During this process, Gassco AS provides its technical recommendations concerning new infrastructure facilities. It’s worth to emphasize that potential collision of interests of investors and authorities may occur at this stage. Commercial companies seek for profit maximization. In other words, their goal is to receive return on investments as fast as possible. The system operator, on the other hand, primarily pursues aims of the continuous development of the gas infrastructure in sense of providing reliability and flexibility in gas market operations in the long run.

Unlike commercial companies, the system operator proposes such solutions that have long term perspectives. For example, commercial companies might advocate for a pipeline with the exact capacity needed for a certain project, while Gassco AS targets to provide an extra capacity. The availability of additional capacity will enable to boost the development of marginal fields by attracting new players for exploration of these fields.

After the concept solution has been accepted, the chosen project operator begins pre-engineering stage and the preparation of the plan for installation and operation (PIO). The PIO is a plan for construction, installation and operation of petroleum facilities such as pipelines, gas processing plants, treatment facilities, etc (The Ministry of Petroleum and Energy 2018). The preparation of

PIO is regulated pursuant to the Act 29 November 1996 No. 72 relating to petroleum activities. It comprises two parts: the installation section and the impact assessment (IA). The objective of IA is to estimate the impacts on the environment and society which arise due to the development of new infrastructure. As the PIO is completed, it is subjected to relevant authorities for consideration and evaluation. MPE in cooperation with other authorities such as NPD and Ministry of Labour and Social Affairs conduct the assessment of PIO. In case of approval, MPE submits the project proposal to the Storting for the final decision. The gas infrastructure planning process is depicted in the Figure 2.5.

As already mentioned, the interests of the government and commercial companies do not always coincide. Therefore, the main objective of Gassco AS is to make a compromise through the proposal of the optimal solution which would satisfy both investors' and the government's interests. During the infrastructure planning process, there is a tight collaboration between Gassco AS and commercial companies in both feasibility studies and commercial research.

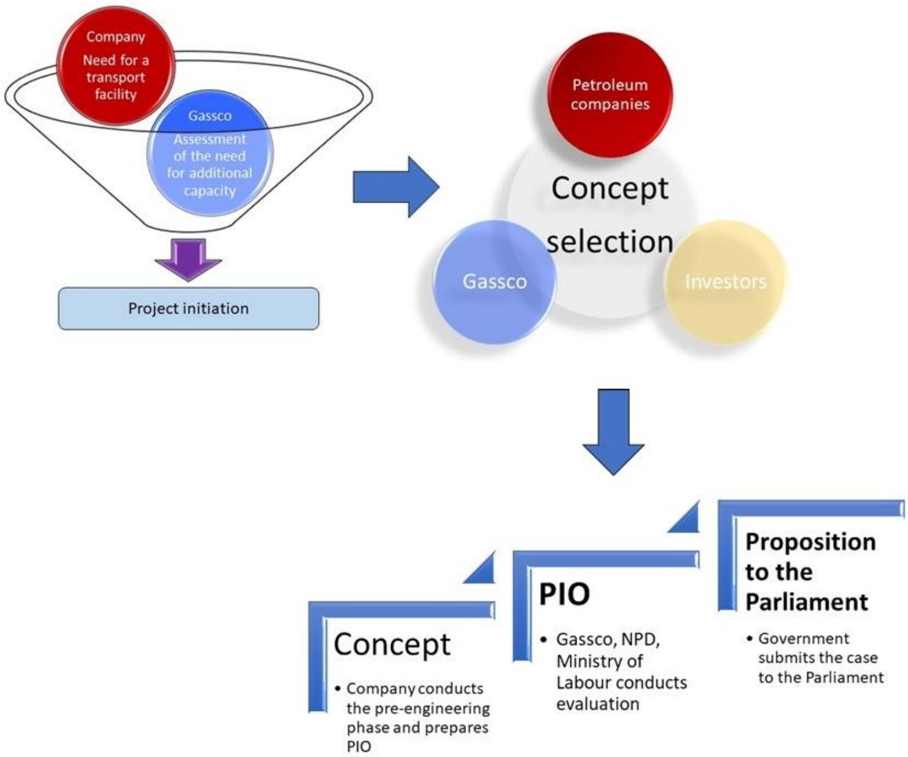

Figure 2-5 Gas infrastructure planning process

However, neither responsibilities of the operator nor the companies' interests include the appraisal of environmental and social impacts on the stage of conceptual studies. These impacts are only investigated by relevant authorities after the concept is selected. In such a case, there is a risk to overlook substantial effects on environment or society. For this reason, it is better to appraise these impacts during the concept development stage. The main idea of our research is to conduct the analysis of above-stated challenges with regard to the gas infrastructure planning process in the Barents Sea due to the fact that the final decision concerning the development of gas infrastructure has not been made yet.

2.4 Motivation for the research

There exists a variety of environmental impacts due to implementation of gas infrastructure projects. These impacts occur during either the construction and normal operation of gas infrastructure. Environmental impacts of gas infrastructure development solutions primarily affect third parties - those who are not directly involved in gas production and transportation. Our research addresses the investigation of one of the most significant environmental impacts of gas infrastructure projects – the impact of carbon emissions. Our main goal is to identify the monetary value of this environmental externality which may be implemented further in economic appraisal of the gas infrastructure development projects. Throughout this thesis we consider several possible solutions for the establishment of gas transport infrastructure in the Barents Sea and propose the best one from the socio-economic perspective.

3 THEORETICAL FRAMEWORK

The aim of the following chapter is to give an overview of the theoretical framework which is implemented throughout the research. To conduct our research, we use CBA as a theoretical framework focusing, however, particularly on the externalities. The evaluation of the rest of the impacts, those on the actual users of the infrastructure and on the gas sector as a whole, is the direct responsibility of system operator Gassco.

The internalization of the externalities in the socio-economic evaluation of a project is a key element of CBA. Therefore, we believe that implementation of CBA framework as a tool for the economic appraisal of the investment projects may contribute to optimal long-term decision-making in gas transport sector in Norway.

The first part describes the theoretical foundations of CBA, which comprises the definition and purpose of CBA, its application area and the main steps. The second section is devoted to the determination of the appropriate value of calculation price for carbon emissions. Sections 4 and 5 describes the economic and environmental impacts of implementation of gas infrastructure projects respectively.

3.1 Theoretical basics of Cost-Benefit Analysis

Regardless the type of an investment project, whether it is a public or private project, it should be appraised from the efficient resource allocation standpoint. Nevertheless, the projects, which represent efficient use of resources and economic profitability for the investors may also entail costs and benefits to third parties. For instance, the project of an establishment of a gas treatment plant provides such social benefits as increase in tax revenues for the state and encourages employment growth. However, on the other hand, the establishment of such facility may lead to substantial air emissions, which is considered as costs from the social point of view.

Cost-benefit analysis is a tool, which is used to consider all the costs and benefits to society of implementation of public or private projects. There is a wide range of theoretical literature related to CBA. Furthermore, in different countries there exist its own practical guides of how to use CBA for the appraisal of public policies. In 2012, the Norwegian Government issued an official report concerning CBA of public measures in Norway. Within this thesis we use Boardman et al. (2011), and Norwegian Ministry of Finance (2012) as primary sources in exploring CBA.

There exist several approaches to the assessment of socio-economic effects of a project. Cost benefit analysis (CBA) and multi criteria analysis (MCA) are the two mostly used in practice. Boardman (2011) provides the following definition of CBA: “CBA is a policy assessment method that quantifies in monetary terms the value of all consequences of a policy to all members of society” (p. 2). According to the CBA methodology, the value of a project is estimated by its net benefit, which is calculated as a difference between social benefits and social costs.

According to Boardman et al. (2011), there are 2 types of CBA. The first of them is *ex ante* CBA. Ex ante CBA is conducted before the implementation of a project. This type of CBA is generally used during the decision making about the selection of one or another project. Unlike *ex ante* CBA, *ex post* CBA is performed after the completion of a project. As all the costs during this type of analysis are considered as sunk costs, therefore *ex post* CBA has only instructive nature. In other words, it contributes to future decision making by the appraisal of measures which were undertaken to a particular project.

3.1.1 Pareto efficiency

A central goal of CBA is to determine the efficient recourse allocation. Boardman et. al (2011, p.27) gave the following definition: “An allocation of goods is Pareto efficient if no alternative allocation can make at least one person better off without making anyone else worse off”.
To describe this principle, it is worth considering the figure 4-1, where the following example is illustrated: 2 people can both agree and get a large margin equal to 100 for both, and not come to an agreement and get only 25 both. On the listed below figure there are shown two extreme points which are marked on the vertical and horizontal axis as $100. These two points represents the situation when each person receives the entire $100. The line, which connects these extreme points, is called potential Pareto frontier and shows all available splits that two persons can have. A part of this line which is bounded with b and c point is called the Pareto frontier. The triangle abc represents all sorts of combinations that would make at least one person better than getting $25, while not making the other party's position worse. The point ($25, $25) is called status quo and it is not Pareto-efficient. The movement from the status quo to any point in the triangle abc is called Pareto improvement.

Based on the above, it should be concluded that any improvement that does not lie on the direct dc makes it possible for any next Pareto improvement, thus not providing Pareto-efficient allocation.

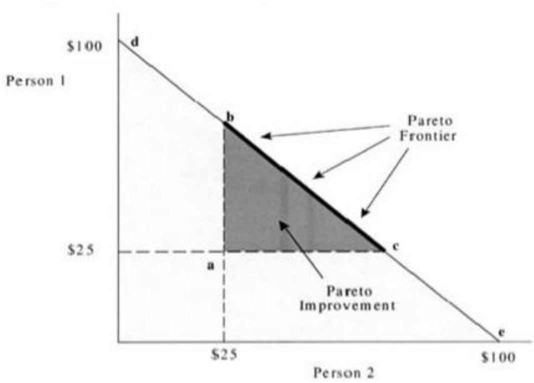

Figure 3-1: Pareto Efficiency. Source: Boardman et al. (2011)

3.1.2 Willingness-to-pay and opportunity cost

In order to better understand how the net benefit of a project is measured we have to consider the concept of the willingness-to-pay (WTP) and the opportunity cost. Under the term willingness-to-pay we understand the maximum amount which individual would be willing to pay to have the policy implemented. On the other hand, there may be individuals who would experience undesirable effects from the implementation of a policy. The minimum amount that an individual is willing to accept to bear with the consequences of a policy is called willingness to accept (WTA). The net benefit from the implementation of a policy is measured by the difference between total WTP and total WTA.

Another important concept underlying CBA is an opportunity cost. The implementation of every new project is referred to utilization of scarce resources such as labor, land, materials or capital. However, all these resources would have an alternative use. Therefore, every project, policy or action has an associated opportunity or alternative cost. The opportunity cost is a benefit of using the resources in its best alternative use. In other words, it measures the value of what society must refrain to implement the policy. Opportunity cost is what we consider as “cost” in CBA. If the project net benefit exceeds the project opportunity cost, it may be recommended for implementation. When the implementation of a policy indicates a better use of resources than its best alternative, we say that the situation satisfies the Kaldor-Hicks criterion (K-H criterion). A Kaldor-Hicks improvement is an economic allocation of resources which has intuitive link with

Pareto improvement, but less strict criterion. The K-H criterion implies that, even if some members of society are made worse off in case of implementation of a policy, the policy provide net benefit if the gainers from the policy could fully compensate the losers (Campbell and Brown 2003). K-H criterion provides the basis for the potential Pareto efficiency rule. Potential Pareto efficiency rule is used in practice for conducting CBA. It states the following: "implement only policies with positive net benefits" Boardman et al. (2011).

3.1.3 Externalities and market failure

In addition to monetized impacts such as capital expenditures or maintenance costs the implementation of public policies and investment projects also entails a range of impacts which do not have a clear monetary equivalent. Indeed, it is not obvious how to estimate in dollars the cost of air pollution or, for example, the consequences of deforestation caused by the implementation of an investment project. Nevertheless, such impacts may have a significant influence on society and therefore should be internalized in CBA according to social value.

In economics the costs or benefits imposed on third parties – those who are not directly involved in project implementation are called *externalities* (Hutchinson 2016). For the first time this term was applied by Pigou (1920) in his book "*The Economics of Welfare*". The externalities could be both positive and negative. For example, the increased transport accessibility provided by the construction of a new airport may be considered as a positive externality for the local business. With a positive externality, the social or so-called public benefits are greater than private benefits. Conversely, externality is negative when social costs are greater than private costs. The common example of a negative externality is air pollution generated by the industry. A processing plant, for example, may operate without taking into account indirect costs caused by air pollution, just because the firm does not bear these costs. However, these costs are real for people and other companies. For example, the people who live near this plant may incur higher healthcare costs or local tourism industry may suffer losses in revenue due to environmental damage caused by air pollution from the plant. The point is, since the indirect costs are not incurred by the processing plant, the actual marginal social costs of production is greater than the processing plant's marginal power cost of production. According to the Figure 4.N the socially efficient output is reached at point B (MSC = MSB). However, the market equilibrium output Q is greater than the socially equilibrium output. The triangle BCA represents the area of overconsumption (social welfare loss). The case of inefficient allocation of goods in the free market is called *market failure*. Market failure happens when prices do not reflect social costs.

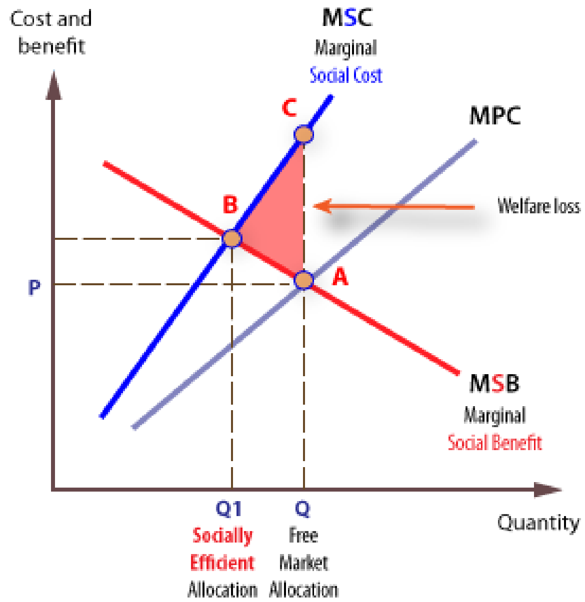

Figure 3-2 Negative externality and market failure (Source: Waldman and Elizabeth (2013))

3.1.4 Steps of CBA

Authors of relevant literature suggest various sequence of actions regarding the implementation of CBA. In our study we focus on the steps which are described in Boardman et al. (2011) and listed below:

1. Find out the number of possible alternatives
2. Identify the stakeholders whose costs and benefits are included
3. Identifying of impacts
4. Forecast the impacts over the life of the project in quantitative terms
5. Evaluate impacts in monetized form
6. Calculate present value of costs and benefits
7. Calculate the net present value (NPV) of each alternative
8. Conduct sensitivity analysis
9. Give a recommendation

1. Find out the number of possible alternatives

At this stage, it is required to specify the set of alternative projects. However, there may exist a large number of alternatives for a single project. It is hard for analyst to compare a large number of alternatives simultaneously. In practice, it is usually considered not more than 6 alternatives. Sometimes, the implementation of a project is unreasonable. Such situation is also may be involved into analysis and it is called “status quo” or zero alternative.

2. Identify the stakeholders whose costs and benefits are included

This step specifies whose costs and benefits are included into analysis. This issue sometimes is controversial. Local authorities stick to provincial perspective taking into account only costs and benefits for local citizens and disregarding costs and benefits of federal or global level. In the opposite, federal governments usually consider only national costs and benefits. This issue is particularly relevant when considering impacts of global significance, such as environmental impacts.

3. Identifying the impacts

There should be identified all the impacts which occur in case of adoption of each of the alternatives. Then their classification as benefits or costs followed by determination of the indicators for each impact take place. The influence on the people's utility is a key point of the impacts that analysts count. Thus, the impacts that have no value to the people are not taken into consideration. In other words, it is necessary to take into account a cause-and-effect relationship between special results and the impacts for human beings. The next step is to specify the impact measurement indicator, which depends on accessible data and a simple transformation to a monetized value.

4. Forecast the impacts over the life of the project in quantitative terms

At this step, it is necessary to quantify the impacts over the life of the project. The initial basis for the forecast is available information about past events. Analysis of the impact of past changes can provide a source of predictions about what may happen in the future if trends remain unchanged. But consideration of such impacts, which tend to lead to changes in human behavior, can only be predicted on the basis of statistical inference and therefore, can be very uncertain. This step is especially crucial and complicated when the considering rare project with a long-run perspective.

5. Impact evaluation in a monetized form

The CBA method provides an estimate of the projected parameters in terms of the total monetary value. This is done using a national or regional currency, such as the dollar or the euro. Sometimes the most important effects are difficult to quantify in monetary terms. It is worth noting that environmental impact assessment is particularly controversial. The CBA widely uses the concept of "willingness to pay", which is used to estimate the cost of output. Willingness to pay can be easily identified from the market demand curve, but in the absence of markets there are problems with its determination.

6. Calculate present value of costs and benefits

As projects have costs and benefits which occur in different years, it is needed a way to aggregate these impacts over time. As the value of money at present is considered as higher than its expected value in the future, CBA uses discounting in order to calculate the present values for future costs and benefits. Future values of costs and benefits are converted to its present values by dividing them by $(1+s)^t$, where s – is the discount rate.

$$PV(B) = \sum_{t=0}^{n} \frac{B_t}{(1+s)^t}$$

$$PV(C) = \sum_{t=0}^{n} \frac{C_t}{(1+s)^t}$$

It is crucial to choose the appropriate discount rate for the analysis to ensure that future project outcomes are not being over- or underestimated. The choice of an appropriate discount rate is usually a matter of dispute. For projects with the duration less than 50 years Boardman et al. (2011) recommend the discount rate of 3.5%. For the projects which have impacts beyond 50 years, the time-declining discount rate is recommended.

7. Calculate the net present value (NPV) of each alternative

The calculation of NPV is a way to determine the economic efficiency of a project. Net Present Value of a project is a difference between the total discounted benefits minus the total discounted costs. Those projects which possess positive NPV are assumed to be feasible. The projects with higher value of NPV are more profitable as compared with projects with lower NPV.

$$NPV = PV(B) - PV(C)$$

8. Conduct sensitivity analysis

The costs and benefits of the alternative depends a lot on the initial data that is used in calculations. Since there may be a substantial level of uncertainty in the identified impacts, monetary evaluation of impacts, the value of a discount rate or in determination of lifespan of a project, the analyst should conduct the sensitivity analysis. Sensitivity analysis allows the analyst to evaluate the range of potential outcomes of the project by varying the assumptions which is used in the analysis. As a result, sensitivity analysis reflects the sensitivity of the NPV to the accuracy in present values of costs and benefits which are used in calculation of NPV.

9. Give recommendations

Based on the obtained values of NPV for each of the alternatives and sensitivity of the results, a decision maker can make a choice in favor of one of the considered alternatives. Nevertheless, it is worth saying that the analyst only gives recommendations regarding the project, the final decision is up to the relevant authorities.

As in our research we primarily concentrate on the estimation of the value of environmental externality due to carbon emissions, only steps 5,6,8,9 are of relevance throughout this thesis.

3.2 Carbon pricing

The following section addresses such an important economic concept as the social cost of carbon (SCC). The main goal is to suggest the appropriate value for the calculation price, which will reflect the social cost caused by the emission of each ton of carbon dioxide. In order to make our estimates we consider the theoretical background of SCC and discuss the existing policies and studies related to the carbon price paths in different countries.

3.2.1 Social cost of carbon (SCC)

Stern (2007) regarded greenhouse gas emissions as negative externalities and labelled climate change as a "*greatest market failure ever seen*". The point is, that carbon emissions cause a climate change, that affects the society globally. In theory, due to the fact, that the influence of carbon emissions on climate does not depend on the location of these emissions, all the economic agents will face the same costs (Hagen et al. 2012). The social cost of carbon (SCC) is a central concept for the internalizing of impacts due to greenhouse gas emissions in CBA. According to the definition provided by OECD (2018), SCC is the estimate of the monetized damages associated with the marginal increase in greenhouse gas emissions. It is worth noting that the carbon emissions accumulate the stock of carbon in the atmosphere and therefore the damages caused by emissions continuously evolve over time. Hence, the optimal SCC should reflect the dynamic nature of impacts on climate due to carbon emissions.

In the optimal theoretical case, the marginal abatement cost (cost of reducing emissions) equals to the marginal social cost of carbon what corresponds to the optimal allocation of carbon emissions on the market and consequently the absence of market failure. Unfortunately, the global market for carbon emissions does not exist at present and it is unlikely to appear in the foreseeable future. The marginal abatement costs vary significantly between different countries and sectors of the economy, while the social cost of carbon remains constant for all economic agents. The question is how to determine the calculation price for carbon emissions for further use in CBA. There is a variety of approaches of putting a price on carbon emissions. Among them are carbon taxes, cap-and-trade systems, implementation of mathematical modeling to calculate the SCC. The results of implementation of these approaches are presented further in this chapter.

3.2.2 Literature on social cost of carbon

There is a wide range of literature providing the different theoretical frameworks on estimation of the SCC. The following passage provides the review of the main results obtained in the range of studies concerning the SCC.

Stern (2007) provides a comprehensive review of the economic aspects of the climate change. The review emphasized that the cost of climate change will be born mostly by civil society. The estimates showed that the potential impacts of climate change on health, water resources, food production and the environment may lead to loss of around 5% to 20% of GDP globally.

Ackerman and Stanton (2012) analyzed the value of SCC provided by the U.S. interagency working group (IWG) in 2010. They showed that many factors of uncertainty were omitted during the calculations of SCC. Taking into account high climate sensitivity, high damages and low discount rate authors performed their own calculations of the SCC. The reanalysis showed that the SCC could be \$900/tCO2 in 2010, rising up to \$1,500/tCO2 in 2050.

Waldhoff et al. (2015) used the FUND 3.9 model in order to estimate the social cost of four different greenhouse gases. For each of the non-carbon GHG the authors found the ratio of the social cost of this gas to the social cost of carbon dioxide. The obtained values were compared with the global warming potentials (GWP) for each gas. The GWP is the measure of how much heat is absorbed by emissions of one ton of greenhouse gas relative to the amount of heat absorbed by one of carbon dioxide which GWP is set to one (EPA, 2017). Under all sensitivities, authors found that the obtained ratios which are also called global damage potentials exceed the global warming potentials. It was concluded that the importance of reducing non-carbon GHG emissions is underestimated in studies related to the impacts of GHG emissions on climate change.

Fraas et al. (2016) considered an issue of whether countries should use the global value of damages incurred by a climate change or concentrate primarily on domestic damages when calculating the SCC. The argument for concentrating on global values was that the global warming caused by CO2 emissions is a global negative externality and therefore all the countries should internalize that externality. However, the global value for the SCC does not provide the clear information concerning the reductions in domestic climate damages. Therefore, the domestic SCC should be calculated as well.

Nordhaus (2017) applied the Dynamic Integrated Climate Economy model (DICE model) in order to estimate the value of SCC. The DICE model was developed by 2018 Nobel Laureate William Nordhaus and currently it is one of the major models which is used for the estimation of the SCC in the US. According to estimates gathered from implementation of the most relevant version of DICE model, the current SCC is approximately \$37.

Ricke et al. (2018) discover the country level contributions to the global social cost of carbon. The authors argue that the global approach in estimating the SCC do not reveal the geography of climate damage and the contributions of different countries to the global SCC. The study represents the estimates of country level contributions to a global SCC obtained from model projections and empirical studies.

Pindyck (2019) discussed drawbacks of integrated assessment models which are currently used in estimating of the SCC and propose his own approach of estimating an average SCC. The author conducted surveys of more than 1000 experts in economics and climate science in order to collect the data related to the probabilities of alternative economic outcomes of climate change and the rate of reduction in emissions which is required to prevent the extreme outcome. As a result, the author obtained the SCC ranging between $80 to $100 per ton of CO_2.

3.2.3 Current use of carbon prices in Norway and other countries

Norway

Today more than 80 percent of GHG emissions in Norway are regulated through a domestic CO_2 taxation system or/and emission trading system. Since 2008, Norway is subject to the EU Emission Trading System (EU-ETS) and about 50 percent of emissions generated by industry sectors are covered by EU-ETS (MPE, 2019). Currently, the EU CO_2 emission allowance price is about 260 NOK per ton of CO_2. The tax rate depends on the kind of fuel and its use. The general tax for the combustion of petrol and natural gas corresponds to 500 NOK per ton of CO_2 (MPE, 2019). The CO_2 tax rates in Norway vary significantly between different sectors. Some sectors, such as petroleum and civil aviation are subject to EU-ETS and also required to pay CO_2 tax, while for example agriculture and fisheries are exempted from carbon taxes at all.

At present, there is no consensus on one joint carbon price that should be used for cost-benefit analysis purposes in Norway. The practical implementation of carbon prices in CBA varies between sectors and is described in sectoral CBA guidelines.

France

In line with the values of average life expectancy and social discount rate the CBA guidance in France also includes so-called "carbon value". This value is applied as a carbon tax for both ETS and non-ETS industries. Currently, the carbon value in France is approximately EUR 32 (310 NOK) per ton of CO_2 and is increasing annually at 5.8% discount rate until 2030 and 4.5 % afterwards (OECD, 2018). The increasing value aims to reflect the increasing damages due to the carbon emissions over time.

The United States

At present, the US has one of the most developed systems to assess the SCC in the world. The estimates are based on three integrated assessment models: DICE, FUND and PAGE. By implementing these models for different emission scenarios and discount rates the Interagency Working Group (IWG) performed the assessments of values of the SCC, which are presented in the table below. As a result, it was recommended to include SCC in CBA of public measures with the value of USD 42 (356 NOK) and 3% discount rate.

Table 3-1 SCC under different damage scenarios and discount rates

USD per ton of CO2			
Year	**Average Impact 5%**	**Average Impact 3%**	**Average Impact 2.5%**
2020	12	42	62
2025	14	46	68
2030	16	50	73
2035	18	55	78
2040	21	60	84
2045	23	64	89
2050	26	69	95

(Source: IWG (2016))

The United Kingdom

Since 2009 the values which are used as calculation prices for carbon emissions for CBA purposes in the United Kingdom are based on ETS emission allowance price if the source is subject to ETS or an abatement cost approach otherwise (OECD, 2018). The most recent estimates of costs for traded and non-traded carbon emissions in the UK are presented in the table below. The switch to the abatement cost approach is caused by the adoption of Climate Change Act in 2008. According to this act, the UK along with the commitments under the Kyoto protocol is also obligated to reduce its net carbon emissions by 80 percent in 2050 compared to 1990 levels.

Table 3-2 Short-term carbon values in the UK (GPB per ton of CO2)

(Source: Department for Business, Energy & Industrial Strategy (2019))

Year	Traded			Non-traded		
	Low	Central	High	Low	Central	High
2019	0	4	7	33	65	98
2020	0	5	9	33	66	100
2021	4	12	20	34	68	101
2022	8	19	31	34	69	103
2023	12	26	41	35	70	105
2024	15	34	52	35	71	106
2025	19	41	63	36	72	108
2026	23	48	73	37	73	110
2027	27	56	84	37	74	111
2028	31	63	95	38	75	113
2029	35	70	105	38	76	115
2030	39	77	116	39	77	116

3.2.4 Carbon price – choosing an approach for Norway

As we have seen so far there exist a variety of approaches for the valuation of carbon emissions in CBA. However, the correct value of the calculation price for carbon emissions depends on what question the analysis should answer. The question is whether the emissions increase due to implementation of a project will result in increase of global emissions or it will be balanced by emissions reduction elsewhere. In the first case, the global marginal social cost of carbon should be used as a correct value for the calculation price. While in the second case, the abatement cost approach should be applied.

The value of the marginal abatement cost depends on the emission reduction target adopted by a particular country. According to recommendations given by Hagen et al. (2012), if the emissions of a country are subject to an international cap-and-trade system and its emission reduction targets are based on the contribution to total global emissions caused by this country, then the international allowance price should be used as a calculation price for CBA purposes. On the other hand, if the country also pursues domestic emission limitation targets, the calculation price will depend on the constraints resulting from such targets. Finally, if the emission limitation targets do not exist, then the calculation price should be based on the global marginal social cost of carbon.

At present, in addition to the commitments under the Kyoto Protocol and participation in the EU-ETS, Norway also has domestic long-term emission reduction targets. Climate Cure 2020 (2010) considered a number of scenarios in order to determine the calculation price of carbon emissions in Norway. These scenarios are based on the estimations of the values of future allowance prices which are needed to maintain the two-degree global warming target.

However, there is still considerable level of uncertainty regarding the choice of the appropriate calculation price for carbon emissions. In our research, we use the calculation price proposed by the High Level Comission on carbon prices. High-Level Commission comprises economists and climate change specialists from all over the world to foster the successful implementation of the Paris Agreement. According to recommendations given by High-Level Commission on Carbon Prices (2017) in order to achieve the two degree target the carbon price should be at least US$40 to $80/tCO2 by 2020 and US$50 to $100/tCO2 by 2030. In our calculations we set the calculation price equals to 524 NOK (US$60) with the corresponding discount rate of 4% recommended by Hagen et al. (2012) as a social discount rate for CBA in Norway.

3.3 Economic impacts of the implementation of gas infrastructure projects

CBA is a commonly used tool for socio-economic appraisal of investment projects in Norway. It is applied for economic appraisal of public decision-making within such sectors as transportation, construction, healthcare, power and defense sectors. The framework for the practical implementation of CBA in public sector in Norway is represented through the guidelines by the Norwegian Ministry of Finance (Ministry of Finance 2005, 2010, 2014), which are based on several official Norwegian reports (Green papers NOU 1997:27 (Hervik et al. 1997), NOU 1998:16 (Hervik et al. 1998) and NOU 2012:16 (Hagen et al. 2012)). Unlike the projects in the aforementioned sectors, investment projects in upstream gas transport sector are financed by commercial companies, which assess the projects only from the commercial point of view. The impacts on the third parties are left out of the scope of the analysis. Within this thesis, we apply the methodology of CBA, which corresponds the practical CBA framework for national use in

Norway in order to perform comprehensive appraisal of the investment project in the Norwegian gas sector.

Many investment projects in petroleum sector are quite risky and lead to significant cost overruns. Therefore, analysis of the social, economic and environmental impacts of the implementation of investment projects in the petroleum industry is crucial.

Shaton and Hervik (2018) divide impacts which occur during the implementation of gas infrastructure projects into three levels. These impacts are schematically presented in the figure below:

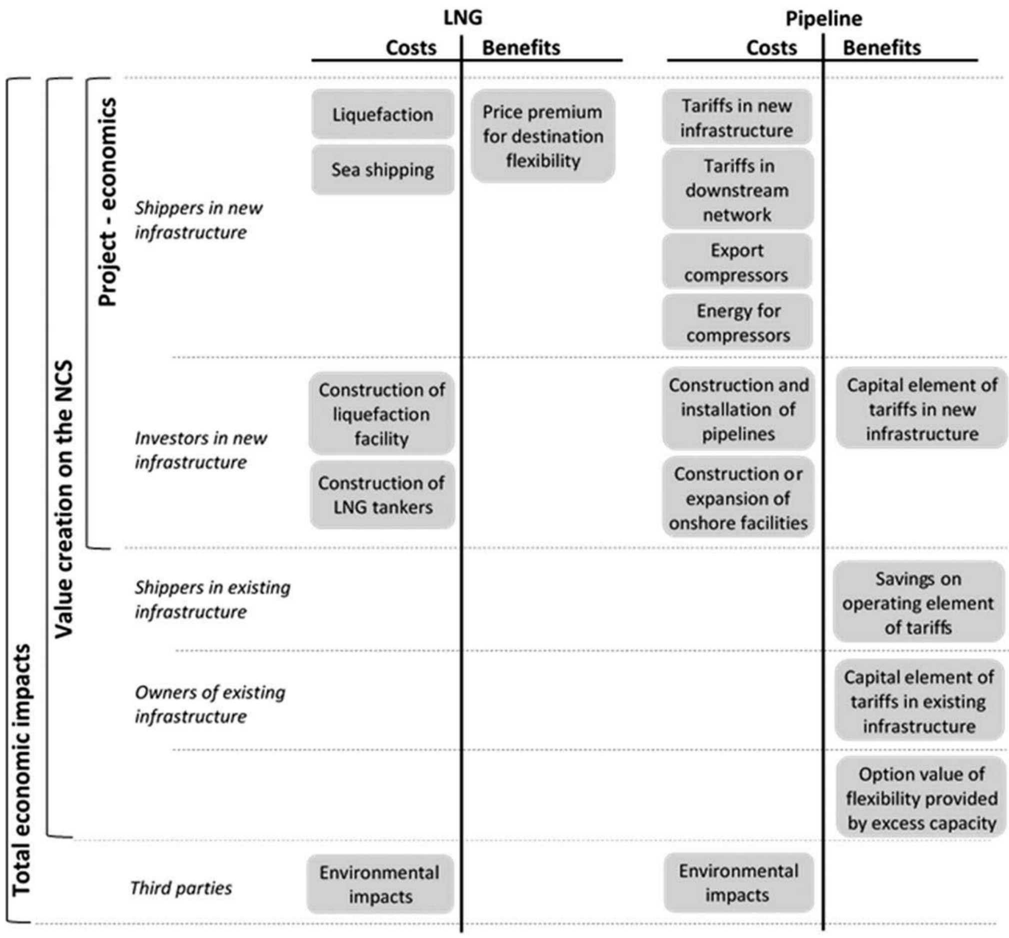

Figure 3-3 Economic impacts of the implementation of gas infrastructure projects

(Source: Shaton and Hervik (2018))

1. Project level

At the project level there are considered the impacts on shippers and investors in the new infrastructure. The NPV which is calculated based on the costs and benefits included at this level represents the economic feasibility of a project from the investors' perspective.

2. Value creation on the NCS

The second level of costs and benefits refers to value creation in gas transport sector. The benefits presented at this level refer to savings on tariffs for shippers in new infrastructure and flexibility provided by excess capacity. However, the impacts related to savings on tariffs refer only to a pipeline solution. The LNG alternative has no impact on the rest of network. The NPV calculation at this level represents the view of the project by the system operator Gassco which main objective is to provide the long term value creation on the NCS.

3. Total economic impacts

The third level represents the total economic impacts of implementation of gas transport projects. The NPV calculation at this level includes also costs and benefits on third parties – those who are not directly involved in implementation of a project. In economics such costs and benefits are referred to the term *"externalities"*. The most significant externality of gas infrastructure projects is environmental impacts due to the greenhouse gas emissions. According to Shaton and Hervik (2018) the cost of environmental externality of a recent gas infrastructure project on the NCS (Polarled Transport) corresponds to 3.14 billion NOK. However at present environmental impacts are not intenalized in economic apparaisal of gas infrastructure projects in Norway.

3.4 Environmental impacts of gas transportation

3.4.1 Pipeline transportation

Pipeline transportation of gas is accompanied by emissions of pollutants and greenhouse gases like NOx, CO2, CH4 and CO emissions due to the operation of gas turbine units at the gas pumping stations. In addition, during repairing of pipeline or during normal operation there are losses associated mainly with the bleed gas (methane) into the atmosphere flange connections of gas transmission equipment. In comparison to LNG transportation, pipeline transportation has the advantage of low hydrocarbon leakage during transportation and low ecological risks.

3.4.2 LNG transportation

From an environmental point of view, natural gas has numerous advantages over other fossil fuels due to the fact that its combustion releases much less CO2, SOx, NOx, and particulate matter into the atmosphere (International Gas Union 2015). At the same time, the life cycle of LNG from the construction of industrial facilities, preparation and liquefaction of gas to its storage, transportation, and regasification has an impact on the environment. Gas liquefaction plants and regasification terminals, as well as LNG transportation, are harmful to the air, soil, water, flora, and fauna. The harm from LNG production is accentuated when located in ecologically valuable territories, where rare species of animals and plants are adversely affected. These acute adverse effects can be expected if natural ecosystems have a low capacity for self-regeneration. For example, would be ecosystems in the high north.

Since LNG is mainly composed of methane, there is a pressing issue of the impact of LNG production and transportation on global climate change. The following passage considers the types of environmental impacts of different stages of LNG production and transportation.

3.4.3 LNG Plant

The environmental impacts occur during the construction of pipelines and natural gas liquefaction plants. Often, fossil fuels are found in places with concentration of other valuable natural resources, including plants and animal communities. As a result, the development of territories and extraction of minerals often causes the transformation of natural ecosystems.

Under construction liquefaction plant damage is caused by different types of activity: clearing of land (including forest clearing), earthworks (excavation and disposal of soil), construction of a paths for vehicles and machinery, and pollution of soil and water objects from possible leakage of lubricants and transported chemicals. The loss of natural habitats of flora and fauna occurs in the areas occupied by the construction of LNG plants and related infrastructure.
Deterioration of air quality is due to the engine exhaust of the required vehicles and to the particulate matter (dusting) when performing earthwork operations. Noise and artificial lighting during construction and operation of various equipment, which are factors of concern for animals, can also be create a negative impact.

During the hydraulic testing of LNG plant equipment and its auxiliary facilities (e.g. liquefied natural gas and condensate storage tanks, process equipment and pipelines), significant volumes of wastewater are generated that require treatment prescribed by regulatory parameters.

During operation, harmful effects on the environment are reduced. However, there still is a constant negative impact during normal production. Contamination of the air with hydrocarbons, carbon monoxide, and oxides of nitrogen and sulfur occur in the process of drying, purification, and liquefaction of gas. The main sources of air emissions are the flare unit, gas turbines, acid gas combustion plants, boilers, and spare diesel generators. Compressors, electric motors, and turbines also create noise effects that frighten animals and birds. In addition, LNG production facilities use large volumes of water taken from the surface of bodies of water for production needs. As a result, significant amounts of wastewater are generated.

3.4.4 LNG terminals

Shipment and subsequent marine transportation of LNG requires the construction (or expansion of existing) of sea ports, equipped with berths loading LNG. Impacts from the construction and operation of a port for LNG loading include coastal and underwater landhafts, surface water, atmospheric air, terrestrial and aquatic biota including benthos, fish, marine mammals, and birds. Extraction of soil during the construction of piers, berths, breakwaters, and other coastal structures has a direct and indirect impact on the environment which is shown in the table 5-2.

Table 3-3 Direct and indirect environmental impacts of LNG terminals

Direct impacts	Indirect impacts
Physical destruction of the underwater and coastal landscape	Changes in water quality as a result of increased concentrations of suspended solids (water turbidity)
Physical destruction of the creatures and plants living there	Discharge of storm water and wastewater
Covering the bottom, coastal, and terrestrial habitats with soil particles	
Changes in the flow pattern and, as a result, the nature and rate of sediment formation	

Air pollution during construction of the seaport and LNG terminal occurs from motor vehicles, terrestrial and aquatic construction equipment, energy-supply installations, and facilities.

In order to ensure the safe passage of gas tankers and their accompanying vessels, it is often necessary to perform dredging operations, during which water-based biological resources suffer. Carrying out this kind of work can even lead to the death of the reservoir's inhabitants. In addition, a significant increase in suspended particulate matter from bottom sediments can have a negative impact on the aquatic ecosystem. To mitigate the negative effect, companies should avoid bottom dredging during fish spawning, as it may adversely redound on survival of eggs and larvae and cause changes in the migratory behavior of underwater inhabitants, which can cause adverse physiological effects. In addition, the high content of suspended particles in the water as a result of secondary agitation (for example, due to the impact of storm surges) hinders the penetration of light into the water, reducing the survival of algae (Bengtsson 2011).

During operation, port facilities often create noise and light effects, emissions of pollutants into the atmosphere, and wastewater discharges into the water area. Furthermore, dredging and dumping of soil leads to changes in hydrodynamic regimes of the water area, which can adversely affect marine biodiversity.

Air pollution can occur when LNG is loaded into the tanker, for example by leakage into pipeline connections. To prevent such leaks, the terminals are equipped with steam traps.

3.4.5 LNG tankers

The impact on the environment of shipping: noise and light (during loading and unloading, as well as during ice movement during the polar night) effects on fish, seabirds, and mammals (Wright 2014) possible leakage of various technical liquids from ships; emissions of pollutants and greenhouse gases into the atmosphere; and discharges of ballast water. The latter factor leads to the deterioration of water quality and the appearance of alien (invasive) species. Biological organisms from other media carried in ballast water can easily take root and spread in the local habitat, distorting its bio balance. This phenomenon is considered one of the four most serious threats to the oceans (IMO 2004). Therefore, modern vessels are equipped with systems of disinfection and destruction of microorganisms, or ballast water replacement in the open sea.

LNG in cargo tanks evaporates into liquefied gas during sea transport, forming a vapor gas used as marine fuel. The excess vapor gas is either re-liquefied or burned in a special device (GCU). Calculations show that emissions of pollutants from LNG combustion into the atmosphere are significantly lower (SOx and particulate matter - by 100%, NOx – by 90%) than emissions from the combustion of marine oil (International Gas Union 2015). LNG tankers emit about 20-25% less carbon dioxide in the atmosphere than the tankers using oil based marine fuels to produce the same amount of energy (Lutskevitsch and Krestyantsev 2015) . Thus, LNG tankers fully comply with international environmental requirements for the content of harmful emissions in the exhaust gases of ships.

3.4.6 Receiving terminals

The operation of the LNG receiving terminal is similar to the port of loading and is characterized by noise and light effects, emissions of pollutants and greenhouse gases into the atmosphere, discharges of wastewater into the fresh water area, impact on terrestrial and marine flora and fauna. Regasification plants have different impacts on the environment depending on the type of evaporation used.

4 CARBON FOOTPRINT ANALYSIS OF GAS TRANSPORT OPTIONS IN THE BARENTS SEA

This chapter addresses the investigation of the appropriate solution for the establishment of the gas transport infrastructure in the Barents Sea. The first section gives an overview of the existing fields and discoveries in the Barents Sea, section 4.2 describes different resource scenarios which were set out by Gassco (2014) in order to compare the potential transport alternatives in that area. Section 4.3 is devoted to the discussion of the gas transportation options which can be implemented depending on the resource allocation and the specificity of the Barents Sea region. In the last two sections we propose the potential value chains and estimate CO_2 emissions for each of the options.

4.1 Barents Sea Resource Potential

The Southern Barents Sea's oil reserves are currently estimated at 3.1 billion cubic meters of oil equivalent.

The share of undiscovered Norwegian shelf reserves in the Barents Sea increased from 50 percent to almost 64 percent. In other words, the Barents Sea is more likely to have undetected oil and gas than the Norwegian sectors of the North and Norwegian seas combined. This year, the NPD expects a new record for the number of exploration wells in the Barents Sea (Norskpetroleum 2018b).

Experts note that in 2017 (Norskpetroleum 2018b), exploration in the traditional production region, the North Sea, reached a minimum over the past 11 years. The Norwegian part of the Barents Sea covers 772000 km^2 and is the largest sea on the NCS. However, only the southern part of the Barents Sea (313,000 km^2) was opened to petroleum activities, and therefore, most of fields are still considered immature.

However, the first discovery in the Barents Sea occurred in 1980s, and exploration has continued for over 30 years. Snøhvit gas field is currently in operation but has experienced significant setbacks during design, construction, and production. Johan Castberg has become one of the largest deposits discovered in Norway in recent years. 49 percent of the still undiscovered hydrocarbon resources of Norway are concentrated in the Barents Sea, another 27 percent are in the Norwegian Sea, and 24 percent in the North Sea (Norskpetroleum 2019a). A record number of wells were drilled in the Barents Sea this year, however exploration activities in the Arctic region gave very modest results for companies.

The NPD is concerned about the current situation. This includes the reduction of exploration in formed oil and gas producing regions with well-developed infrastructure. After 2025, the oil on the continental shelf of Norway could be significantly impeded, if new fields are not opened. By the end of 2016, in the Norwegian part of the North Sea 62 deposits were developed, while in the Norwegian Sea 16 were developed, and in the Barents Sea only two deposits were developed.

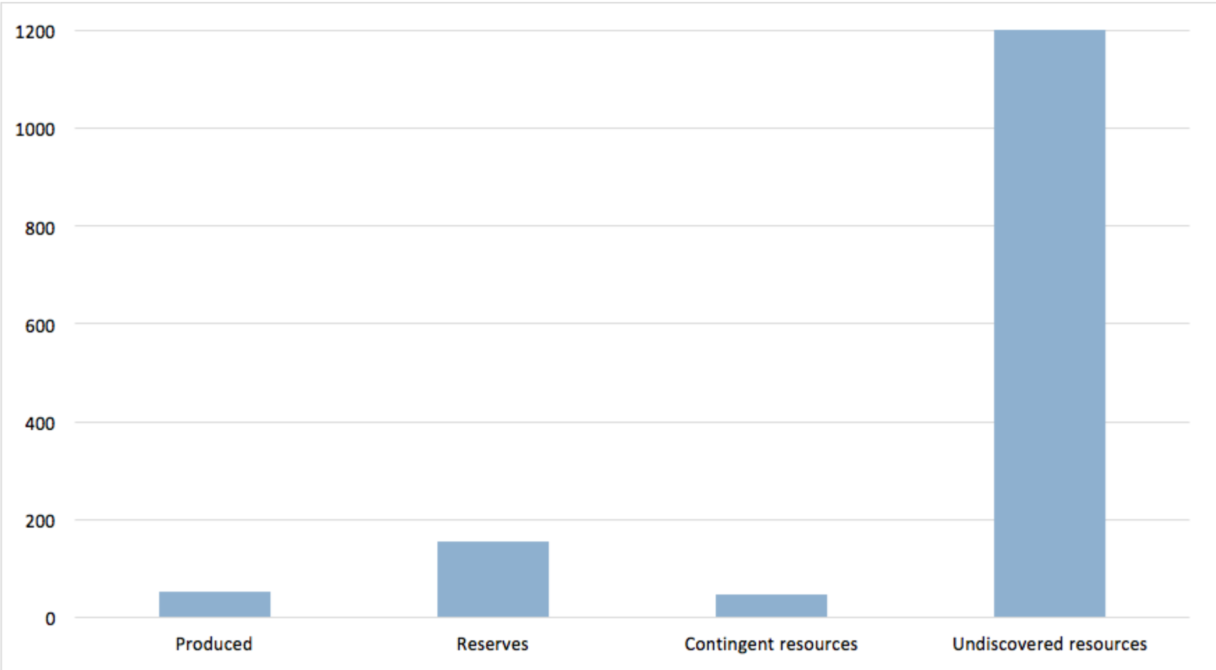

Figure 4-1 Barents Sea gas resource estimates (Source: Norwegian Petroleum Directorate, 2018)

4.2 Resource scenarios

There are a number of possible scenarios for the future gas production from the fields of the Barents Sea. Gassco in its report (Gassco, 2014) considered five volume scenarios to cover the potential outcomes for the exploration activities in the Barents Sea during the period from 2014 to 2017. All the scenarios were obtained from the Monte Carlo simulations with the following variables: resource size, number of discoveries, size of the largest discovery, production characteristics, distance between discoveries and distance to shore (Gassco, 2014). The total volume of the resources in the existing fields and discoveries in the Barents Sea region was about 200 BCM, therefore 200 BCM was taken as initial point for each of the scenarios. The outcomes of the five considered scenarios are represented in the figure below.

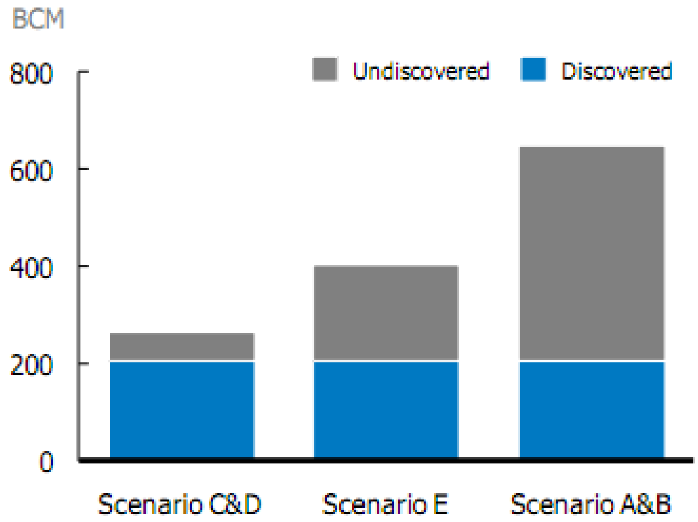

Figure 4-2 Resource scenarios (2014-2017) (Source: Gassco, 2014)

Scenarios C&D correspond to the low resource outcome, A&B represent the high resource outcome and E refers to the median case.

Actually, during the period from 2014 to 2018 the amount of discoveries in the Barents Sea region was increased by two 5F and two 7F discoveries which possess the resource base of 32.87 MScm o.e in total (Norskpetroleum 2018b).

Table 4-1 The Barents Sea discoveries (Source: Norwegian Petroleum Directorate, 2018)

Discovery name	Area	Disc. year	Resource estimate	Type	Resource class
7120/12-2 (Alke Sør)	Barents sea	1981	12,97	GAS	5F
7121/5-2 (Snøhvit Beta)	Barents sea	1986	2,42	OIL/GAS	5F
7122/6-1 (Tornerose)	Barents sea	1987	3,78	GAS/CONDENSATE	4F
7120/1-3 (Gohta)	Barents sea	2013	6,50	OIL/GAS	5F
7219/8-2 (Iskrystall)	Barents sea	2013	2,38	GAS	5F
7220/7-2 S (Skavl)	Barents sea	2013	3,51	OIL/GAS	5F
7220/11-1 (Alta)	Barents sea	2014	24,00	OIL/GAS	5F
7220/4-1 (Kramsnø)	Barents sea	2014	2,28	GAS	5F
7220/6-2 R (Neiden)	Barents sea	2016	3,46	OIL/GAS	7F
7219/12-1 (Filicudi)	Barents sea	2017	3,14	OIL/GAS	7F

As depicted in the table above there is a mismatch between the estimates of discovered resources provided by Gassco (Gassco, 2014) and the actual discoveries during the period within 2014 to 2018. According to Gassco estimates the volume of discovered resources even in the low resource outcome scenarios account for 60 BCM (figure 4-2), whilst actual volume of discovered resources of natural gas is less than 30 BCM, taking into account that the proven discoveries contain also oil reserves. Although Gassco's forecasts concerning the discovered resources have not been made, the intensity of exploration activity on the NCS remains at the high level. Therefore, taking into account that the Barents Sea region contains about 67% of the total undiscovered resources on the NCS, new substantial discoveries are yet to come in near future. The long-term estimates of future discoveries provided by NPD is depicted in the figure below.

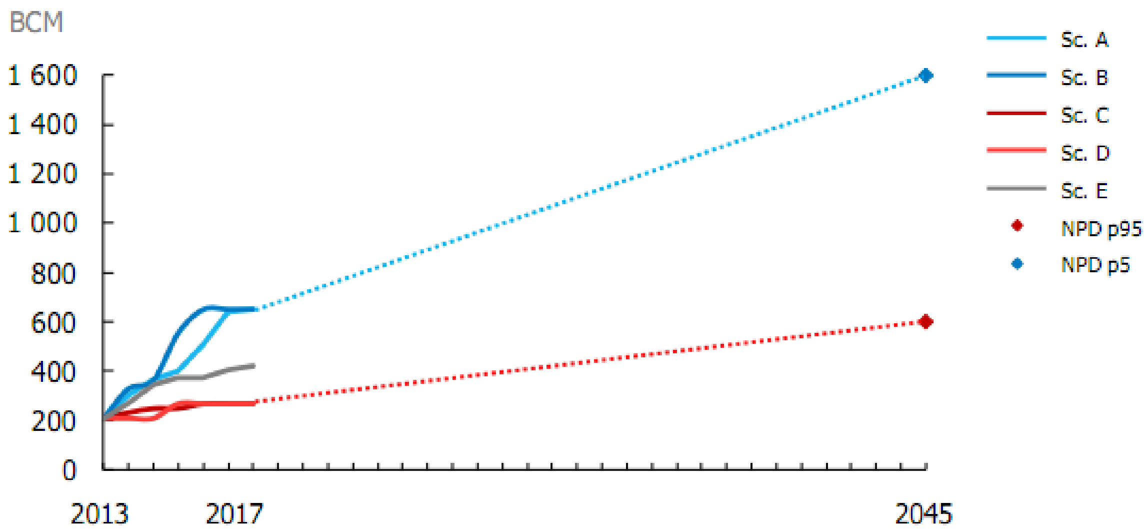

Figure 4-3 Long-run resource scenarios (Source: Gassco, 2014)

4.3 Transportation options

Gassco in its report (Gassco, 2014) considers three transportation alternatives as viable options for the establishment of gas transport infrastructure in the Barents Sea. Among them are: 32-inch pipeline, 42-inch pipeline and the development of a new LNG train at Melkøya.

4.3.1 Pipeline

Economies of scale is an important criterion during the decision making concerning the pipeline diameter. Besides the additional revenue due to increased throughput, the additional capacity of a pipeline provides a possibility for the future tie-ins from new developments. Larger diameter of a pipeline is potentially more preferable to increase economies of scale. Nevertheless, the larger the diameter of pipeline, the more powerful compressor is needed to sustain the throughput of a transmission system, because an increase in diameter entails the decrease in pressure between inlet and outlet of a pipeline due to increased friction between gas and inner wall. For the same reason the increase in length of pipeline will lead to decrease in pressure. The capacity of a pipeline depends on diameter, volume and pressure. Therefore, in order to obtain a greater transport capacity and thus economies of scale it is needed to consider tradeoffs between these parameters. The optimal combination of these parameters is defined by using optimization software. Gassco in its calculations uses a Gassopt model (Rømo et al. 2002).

Ingenbleek (2018) compared the investment as a ratio to capacity and the influence of diameter on a transport capacity for eight gas pipelines on the NCS in order to evaluate the economies of scale. The calculations showed that during the last 30 years the capital costs of pipelines have decreased whilst the capacity of pipelines increased, which means the growth in economies of scale. According to Ingebleek (2018) 42-inch pipeline is financially more attractive option than 32-inch pipeline. This corresponds to BSGI report by Gassco, in which the 42-inch pipeline is more preferable option in four out of five scenarios (Gassco, 2014).

4.3.2 LNG

The LNG plant on the island of Melkoya in the Northern part of Norway is part of the liquefaction of natural gas project for the fields of Snøhvit, Albatross, and Askeladd in the Barents Sea (the sea depth is 240-345 m). This facility is located 140 km northwest of the Norwegian city of Hammerfest. The Snøhvit field is the largest of the three fields developed under the project, which accounts for 50 percent of the available reserves. This LNG plant is located at the highest latitude (71 degrees North) of all similar facilities in the world and is equipped with Europe's first LNG export terminal (Verdict Media Limited 2019).

At the end of 2006, a huge volume of LNG was delivered to Hammerfest, which became a milestone for the implementation of the project. This gas was delivered from Egypt by the tanker Arctic Princess with LNG capacity 147,200 m^3. The Arctic Princess is the first vessel of its type, which was specially built for the transportation of LNG produced on the Snøhvit project. The robust design of the vessel enables its long-term operation in the harsh environmental conditions typical for the North Atlantic, especially in winter.

The gas produced from the Snøhvit field of the project contains 5% to 8% CO_2. The development project allows for the separation of carbon dioxide from CO_2 at the Melkøya plant and its use for the re-injection at the Snøhvit field into the sandy Tubasen horizon at a depth of 2600 m. The construction, operation, and maintenance of CO_2 injection systems will be expensive, but their implementation will avoid unacceptable emissions into the environment.

The LNG plant in Hammerfest will be the first to introduce a technical solution with a full transition to the electric drive. This includes five light gas turbines of the aircraft type LM6000PD, which use gas from the field as fuel. This technology is another innovation introduced over the course of the project.

4.4 Transportation scenarios

In our research, we consider three different value chains to establish the gas transport infrastructure in the Barents Sea. Given scenarios are based on the existing pipelines and gas treatment facilities on the NCS. The considered scenarios are presented in Figure 4-4.

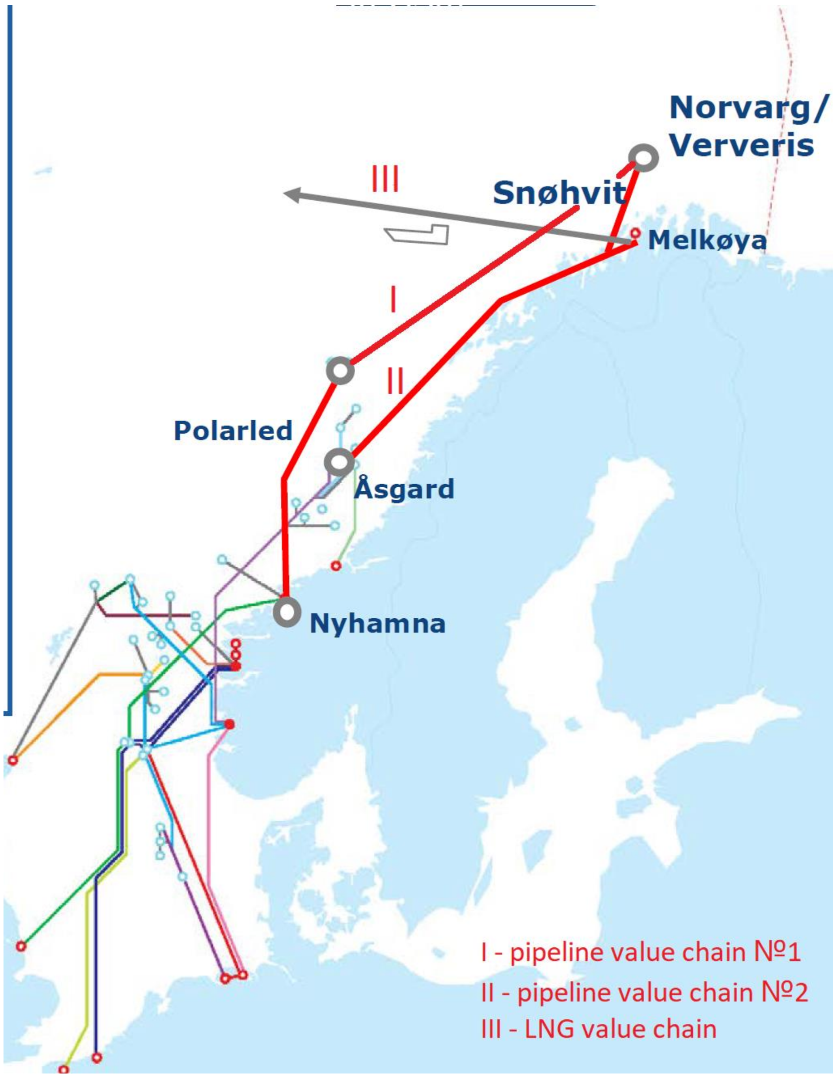

Figure 4-4 Potential gas transport solutions for the Barents Sea (Source: adapted from Lohne, 2013)

4.4.1 Pipeline value chain

The first value chain which we are going to consider is depicted in Figure 4-5.

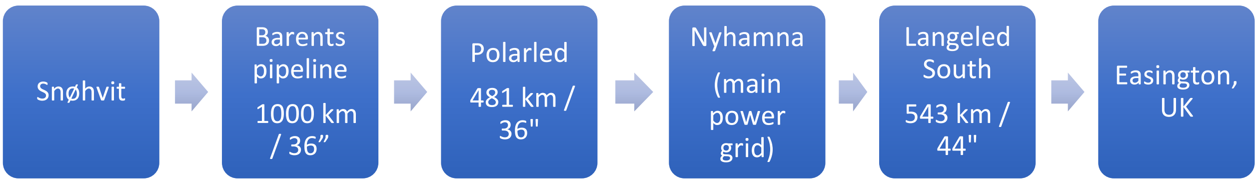

Figure 4-5 Description of value chain №1

The development of the region around the Aasta Hansteen field contributes to the development of a very promising part of the NCS. In order to ensure the possibility of expanding the infrastructure at any time, six T-shaped pipe connectors were implemented. Thus, additional fields can be easily connected to the gas pipeline at a later stage. In 2018, new natural gas fields were discovered in the nearest area of the Aasta Hansteen field. Currently, the plan is to deliver the gas from these deposits to the shore also via the Polarled pipeline. The Polarled gas pipeline, with a diameter of 90 cm (36 inches), is the deepest gas pipeline of this scale, located at a maximum depth of 1,265 meters. The length of the pipeline is 482 km and the capacity is 70 million scm of gas per day. This capacity is enough to take not only gas from Aasta Hansteen, but also from fields developed jointly with it. Polarled is designed to transport gas from the Aasta Hansteen field to the integrated gas treatment plant at the Nyhamna terminal on the West Coast of Norway. After gas processing in Nyhamna, gas is exported via the second longest underwater export gas pipeline in the world, Langeled (1200 km), which connects the terminal and the city of Essington, located in the northwest corner of the UK.

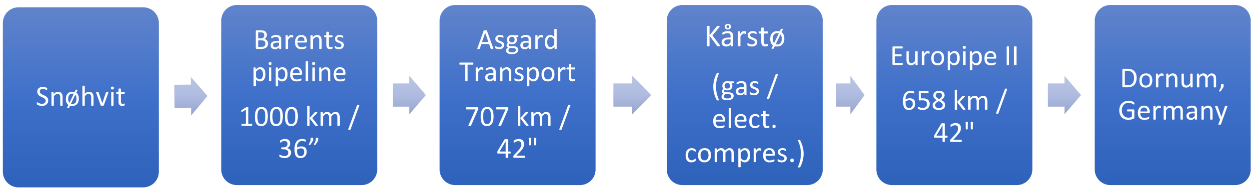

Figure 4-6 Description of value chain №2

The Asgard oil field is located 200 km from the coast of Norway at a depth of 240-300 m. The facility built for its development includes a single-hull oil-producing unit (Asgard A), the world's largest semi-submersible gas-producing platform (Asgard B), a vessel for storage of Asgard C oil and gas products, and other equipment necessary for the development of underwater fields. This underwater system, one of the largest in the world, combines 52 wells. These wells are grouped into 16 baseplates and connected by 300 km of underwater pipelines. The water depth at the point of installation of the Åsgard B platform is 310 m. The transport of gas from the Åsgard field is completed in the 42-inch pipeline with a length of 700 km to the Kårstø treatment plant, located north of Stavanger. The gas is then transported to European consumers through Norway's extensive network of gas pipelines.

The connection of new fields to the existing infrastructure is possible thanks to the unusual approach implemented at the Åsgard field. A kind of a "web" of pipelines was created to connect the existing infrastructure and new fields. The implementation of such engineering concept allowed to cut the costs of the project by half. The extracted volumes of the gas is sent to the Kristin platform for primary processing. Heidrun Platform delivers water for further injection into the field. Åsgard B will deliver the necessary gas for production through the underwater installation of the Tyrihans D field. The refined oil will be transported to the Åsgard B platform for storage and further loading into tankers. The extracted natural gas will be sent by pipeline to the gas distribution station in Åsgard and then will go further to the industrial base in Karstø.

However, comparing with Langeled and Polarled gas pipelines, Åsgard has not a spare capacity for receiving and transporting gas.

4.4.2 LNG value chain

The next alternative which we are going to evaluate as a gas transport infrastructure solution for the Barents Sea is the expansion of the existing processing capacity of the LNG plant at Melkøya. LNG plant at Melkøya is the northernmost LNG processing facility in the world. It was put into operation in 2007 and is operated by Equinor. The unprocessed well stream arrives to Melkøya through the 145 km pipeline from three gas fields: Snøhvit, Askeladd and Albatross. The extraction of natural gas from these fields is performed by the subsea production system which is located at 250-345 meters below sea level. The subsea production system and the upstream transport pipeline are controlled from shore. Rich gas arriving to processing facility undergoes the pretreatment processes including carbon dioxide removal, de-hydration and mercury removal and then is converted to LNG by decreasing its temperature to -163ºC. The separated carbon dioxide is returned back to the field through a special 8-inch pipeline where it is reinjected into the storage reservoir below the gas bearing formation. Such carbon capture and storage (CCS) process enables to decrease carbon emissions by 700 000 tons per year. Before being shipped LNG is stored in large tanks. Finally, LNG is exported to the relevant markets in Southern Europe, Asia and North America.

The annual production capacity of LNG train at Melkoya is 4.3 million tons of LNG, 800000 tons of condensate and 250000 of liquefied petroleum gases (LPG). Currently the production capacity of the Melkøya LNG plant is fully utilized. In order to meet the natural gas production growth and therefore to ensure the sustainable development of the discoveries in the Barents Sea, we consider an opportunity of building a second LNG train at Melkøya.

In order to provide the reasonable comparison of the emission intensity from pipeline value chains with LNG value chain it makes sense to apply for calculations the proportionate distances from the field to the destination point. Despite the fact that the LNG from Melkøya is exported also to the US and Asia we use the following value chain in our analysis:

Figure 4-7 LNG value chain

4.4.3 Estimates of emission intensity of the transportation solutions

Unit CO2 emissions from pipeline chains were gathered from the Shaton (2017), where the author distinguishes emissions occurring during the upstream and export transportation respectively.

Table 4-2 Emission intensity of pipeline gas transportation (Source: Shaton, 2017)

	CO2 Unit Emission, kg/ Sm^3 o.e.	Upstream Transportation, kg/ Sm^3 o.e.	Export Transportation, kg/ Sm^3 o.e.
Asgard – Europipe II	**110,99**	**44,76**	**17,92**
A.Hansteen - Langeled	**34,24**	**23,38**	**-**

We estimate the emission intensity of the LNG chain in the following way. Taking into account that the subsea production system is powered from shore and that the feed gas is transported to the facility under its own pressure we set the emissions from upstream transportation equal to zero. As we discussed before the life cycle of LNG consists of three steps: pretreatment and liquefaction, transportation and regasification. Since the regasification is carried out by the final customer which is located outside the Norway, we do not consider emissions due to regasification process in our analysis.

The major part of carbon emissions of the considering LNG chain arises due to pretreatment and liquefaction processes at the onshore facility. The process of liquefaction of natural gas requires significant amount of energy. The energy which is required for the operation of the Melkøya LNG plant is generated by five gas turbines which are fired by the locally refined feed gas. Each of these 46 MW gas turbines provide energy for the refrigerators and other parts of LNG train. The overall installed power is 230 MW. According to Heiersted et al. (2001) such kind of energy system produces 900000 tons of CO_2 emissions annually. Given the production capacity of 4.3 mtpa (5.93 million Sm^3 o.e.), the CO_2 emission intensity equals 151.77 kg/ Sm^3 o.e.

It is assumed that in all 12 months of the year LNG is transported by chosen route. The planned capacity is 4.5 million tons of LNG per year. The density of LNG is 442 kg / m^3, which gives an annual LNG volume of 37,330 thousand m^3.

The Arctic Princess tanker is used for transportation. Each tanker holds about 145,000 m3 of LNG. The capacity of each tanker is 25 MW (80% of the maximum capacity declared by the manufacturer, since part of the engine power of the vessel provides energy to auxiliary systems on the ship). The speed of the tanker in clear water is 15 knots. It is possible to calculate the duration of routes for gas tankers after taking into account the length of routes. Thus, the route to Zeebrugge for gas tankers will take only six days (http://www.skipslistene.no).

Gas tankers are equipped with dual-fuel engines - Kawasaki KHI WA-400. Kawasaki engines are designed for LNG, heavy diesel or low-viscosity diesel engines. However, LNG is the main fuel. Gas engines emit 85 percent less nitrogen oxides (NOx) and 25 percent less CO_2 than marine diesel engines. In addition, emissions of sulphur oxides (SOx) and particulate matter from natural gas combustion are almost zero.

Emission factors are used to estimate the amount of air emissions from LNG transportation by gas tankers. These factors are defined as the amount of the emitted pollutant per unit produced by the company. The main emissions from a tanker's fuel combustion are CO_2, SOx, NOx, CO, particulate matter (PM), and hydrocarbons (mainly methane CH_4).

The Kawasaki KHI WA-400 engines, which are installed on tankers, will use LNG and diesel fuel (up to 1%) to ignite the gas and establish stable engine operation (Kawasaki 2015). Then, using emission factors from the combustion of natural gas and diesel fuel, it is possible to calculate the emission factors, greenhouse gases, and other pollutions.

Table 4-3 Emission factors from LNG transportation by gas tankers

	Emission factors from LNG transportation by gas tankers, g/kWh
CO2	427,83
NOx	1,383
SOx	0,0399
PM	0,0341
CO	1,292
CH4	3,965

To estimate the emissions during the loading and unloading of tankers in the port, available data for tank analogues with a cargo capacity of up to 155 000 m^3 was examined. The emission factor for Wärtsilä 50DF engine was used for CO_2 emissions (Wärtsilä Engines 2014). Emissions for one tanker during loading and unloading at the port are presented in the Table 5-5.

Table 4-4 Emissions occurring during the loading and unloading processes

	Emissions during loading and unloading of tankers, kg
CO2	62236
NOx	250
SOx	0
PM	0
CO	150
CH4	100

Next, the total number of annual emissions from tanker transportation is estimated using the emission factors of pollutants, capacity of the tankers, and the total travel time.

Emissions from tankers = Power x Travel Time x Emission Factors + Emissions from Loading-Unloading. The total emissions from LNG transportation are presented in Table 5-6.

Table 4-5 Total emissions from transportation of LNG

	Emissions from the LNG carrier, ton per year		
	Transportation	**Loading-unloading**	**Total**
CO_2	140542,2	25,4	140567,6
NOx	454,3	10,2	464,5
SOx	13,1	0	13,1
PM	11,2	0	11,2
CO	424,4	61	485,4
CH4	1302,5	41	1343,5

Since the impact of CO_2 emissions is much more significant comparing to other emissions, for the simplicity in our research we investigate the impacts caused only by CO_2 emissions. The total CO_2 emissions occurring in the LNG value chain are presented in the table below.

Table 4-6 Total CO_2 emissions from LNG value chain

	Annual CO_2 emissions, ton per year				Unit CO_2 emissions, kg/Sm3 o.e.
	Liquefaction	Transportation	Loading-unloading	Total	Total
CO_2	900000	140542,2	25,4	1 040 567,6	286,2

5. ELECTRICITY GENERATION PATHS

The common characteristics of the above-mentioned gas transportation chains is the use of electricity generated by the combustion of natural gas for the operation of compressors. There are different classifications of booster compressor units and stations (BCS), for example, by the type of turbine, which depends on what type of fuel can be used for the BCS. Due to the fact that such equipment is often located far from transport routes and in hard-to-reach places, the possibility or inability to supply a particular fuel may become crucial. The following types of turbines are most commonly used:

- gas-turbine;
- electric.

Gas turbines account for about 90% of the total CO_2 emissions of the chains when the processing facility or LNG plant are not connected to the main electricity grid onshore. The main components of the gas turbine unit are the compressor, combustion chamber, and turbine. This type of drive is widespread because it is not tied to the supply of fuel from the outside, operates on the same gas that pumps the BCS, and the excess energy produced can go to heating and electricity supply of the station itself, as well as other nearby facilities.

Despite the need for mandatory supply of electricity, a BCS with an electric drive has a number of advantages over gas turbine plants. First, the use of electricity saves the pumped fuel itself, and also has a positive impact on the environmental friendliness of the BCS by reducing harmful emissions into the atmosphere. Secondly, the electric motor is much easier to adjust and automate, which greatly simplifies the control of the entire station and reduces the required operating personnel. Finally, the electric drive option significantly improved working conditions on such BCS by reducing installation noise, vibration, and dust.

However, this connection requires a huge investment in electricity infrastructure. These investments are vital if there is enough available primary resources for "green energy", like hydro or wind. In addition, renewable resources are very sensitive to weather changes, which can affect the volume of electricity production, and therefore its price. For example, in the spring of 2018, Norway imported electricity from Denmark and Sweden when a dry, warm spring led to the depletion of the country's hydropower reserves. Therefore, the price of electricity increased.

5.1 Scandinavian Electricity Market

The electricity market is a necessary component of the electric power industry in all developed countries. The market mechanism is proven as the most effective way to promote industry development. Competition is integral part of the electric power industry in all countries with a liberalized energy market. During the reform of the electricity sector, the establishment of a competitive market was one of the main objectives.

The integrated power system of the Scandinavian countries, Nordel, is one of the largest associations on the European continent. It has the authority to consolidate all network companies and coordinate the work of system operators. Nordel is a non-profit organization and does not have its own budget. Nordel should implement the technical coordination of the integrated system and make recommendations in the following areas:

- development of energy systems and development of rules that allow network management;
- generating electricity, ensuring reliable electricity supplies and information sharing;
- assessment of the cost of energy transmission over networks and the implementation of support services;
- international cooperation;
- maintaining and developing contacts in the field of energy, especially in Scandinavian and European countries;
- preparation and promotion of information about the Scandinavian electricity market;

- in addition, Nordel is a link between system operator and power consumers.

The overhaul of the electricity industry in Scandinavian countries involved the following: improved legislation, creation of wholesale and retail electricity markets, separation of accounting by type of activity, equal access to the network's infrastructure for producers, and balancing the electricity prices in different regions.

Norway is the first Scandinavian country to publish a liberal law concerning the electric power industry. It began to operate from January, 1991 and defined the following basic principles of cooperation:

- market relations are established based on competition in the areas of production and sale of electricity;
- the system area network remains in state ownership as a monopolistic sphere;
- energy companies must separate reporting by activity - generation, distribution, sales;
- network owners are obliged to ensure the transportation of electricity for any supplier or consumer under the same terms.

As a result of the new law, two independent, Norwegian state-owned companies were formed – generation company Statkraft SF and network-based Statnett SF. The next stage of market development was the admission of small consumers. An important feature of the Norwegian energy market was that electricity consumers were able to change their supplier without any additional costs, which contributed to the development of competitive relations. Then wholesale and retail electricity markets began to emerge in the country.

The power industry reform in other Scandinavian countries proceeded in a similar way and created the prerequisites for organizing an integrated international electricity market. The Nordpool exchange, established in 1993, allowed contracts and financial instruments for the supply of electricity to be traded. Sweden joined it in 1996, Finland in 1998, and Denmark in 2000. Nordpool's participants have the right to conclude bilateral purchase and sale agreement for electricity power or to trade on the exchange. About 70% of the total electricity is sold under bilateral agreements.

Nordpool Exchange is organized in four independent markets - spot, futures, options, and base. Nord Pool Spot AS is a market for physical electricity power turnover. The physical supply market is divided into two sectors: Elspot and Elbas.

Elspot barters and creates contracts for the physical supply for the day ahead. There are a lot of external factors which influence the emerging price of electricity. The main factors are:
- Air temperature: When a decrease in ambient temperature occurs, the demand for electricity and market price increase immediately;
- The price of CO_2 quotas in the world market: Since the price of electricity from the largest electricity producer depends on the price of the CO_2 quota purchased;
- Water resources of the Nordic countries;
- The ratio of supply and demand.

The application of the participant indicates the price at which he or she is ready to buy a certain amount of electricity and the price at which he or she is ready to sell this volume. For example, the owners of hydroelectric power stations consider the actual water reserves on a day-to-day basis. When they predict increase in water price, they can decide not to produce electricity themselves, but to buy it on the market and vice versa.

In the Elbas market, trading is carried out immediately prior to delivery in order to balance the supply and demand of electric energy. This part of the market has been effectively functioning since 1998. Today, the energy production and consumption balance is drawn up two hours before the moment of delivery.

The spot market is the most important benchmark in the electricity market and is Statnett's indicator of industry condition, as this market shows changes in production, demand, and supply. Futures and forward contracts can be concluded for a period of one day to three years. Purchase and sale option contracts are obligations to complete future contracts. Purchase of an option contract allows to implement the contract at the lowest price.

The purpose of the electricity exchange is to provide market participants with equal opportunity to buy or sell electricity, while also serving as an alternative to bilateral agreements. The electricity exchange guarantees transparent pricing policy for electricity, which gives investors and producers a basis for assessing the market situation allowing them to make informed, market-based investment decisions.

Electricity flow between different cost fields always occurs from the lower cost field to the higher one. Different fields costs occur when demand in one field exceeds capacity between two fields. Nord Pool applies an implicit tender or method based on indirect calculations in order to avoid wide disparities among the fields. Created system optimizes costs between cost zones and with further step of calculating costs takes into consideration capacity between two zones, thereby costs become equal. Therefore, interregional electric lines make an opportunity to direct electricity from lower cost or excess zone to that one with demand or higher price.

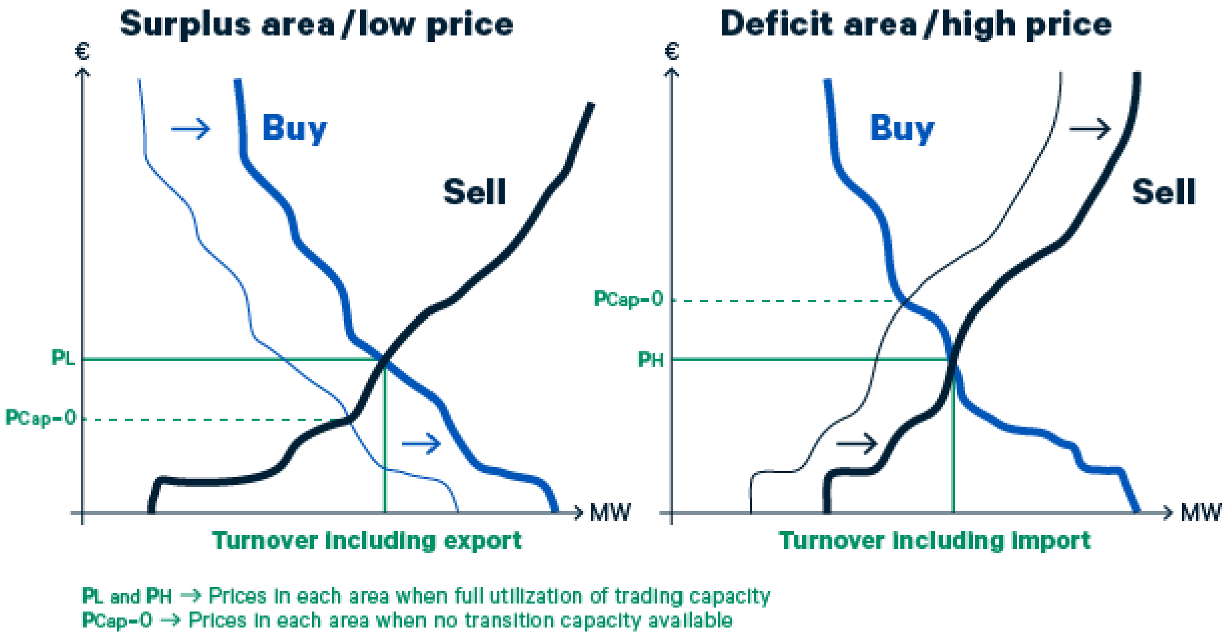

Figure 5-1 Nord Pool price calculation (Source: NordPool)

5.2 Transportation scenarios distinguished by the source of power supply

Taking into account the possibility of import of electricity to Norway, we distinguish previously considered transportation scenarios by the sources of power supply.

Table 5-1 Transportation scenarios distinguished by the source of power supply

Scenario	Transportation chain	Electricity generation
Scenario 1.1	Snøhvit – Europipe II	Domestic – Gas turbine
Scenario 1.2	Snøhvit – Europipe II	Import – France – Nuclear Power Plant
Scenario 1.3	Snøhvit – Europipe II	Import – Poland – Coal Power Plant
Scenario 1.4	Snøhvit – Europipe II	Import – Sweden – Hydro Power Plant

Scenario 2.1	Snøhvit - Langeled	Domestic – Gas turbine
Scenario 2.2	Snøhvit - Langeled	Import – France – Nuclear Power Plant
Scenario 2.3	Snøhvit - Langeled	Import – Poland – Coal Power Plant
Scenario 2.4	Snøhvit - Langeled	Import – Sweden – Hydro Power Plant
Scenario 3.1	Snøhvit - Zeebrugge	Domestic – Combine Heat and Power Plant
Scenario 3.2	Snøhvit - Zeebrugge	Import – France – Nuclear Power Plant
Scenario 3.3	Snøhvit - Zeebrugge	Import – Poland – Coal Power Plant
Scenario 3.4	Snøhvit - Zeebrugge	Import – Sweden – Hydro Power Plant

CO2 emissions from electricity production in France, Poland, and Sweden are calculated on the basis of the following logic:

$$V_{CO2} = Q \cdot \delta_{CO2},$$

Where

V_{CO2} – total CO2 emission, ton CO_2-eq;

Q – amount of electricity produced, MWh.

δ_{CO2}– emission conversion factor, ton CO_2-eq/MWh.

In our research, we use LCA default emission factors, which considers emissions from all supply chains, including emissions from operation, transportation, and processing (Koffi et al. 2017). This is particularly important for renewable energy: while the carbon content (or concentration) in the fuel can be CO_2 neutral, other activities can lead to significant CO_2 emissions. For example, greenhouse gas emissions from nuclear power are associated with different stages of the nuclear fuel cycle:

- uranium mining, extraction, and enrichment;
- construction, modification, and decommissioning of reactors;
- processing of wastes;
- transportation of uranium and fuels (Sovacool 2008)

Electricity production from hydropower plants does not require burning hydrocarbons. At the same time, artificial storage, which is indispensable for the operation of hydroelectric power plants, is a large source of greenhouse gas emissions. Methane is produced at the bottom of tanks where organic matter, trees, and herbs decompose. Some of the methane is converted into CO_2, the rest is carried to the surface in the form of bubbles. Thus, artificial reservoirs annually emit approximately a billion tons of greenhouse gases — 1.3% of the total global emissions (Li and Zhang 2014).

Scenarios 1.2, 2.2, 3.2 – import of electricity generated at nuclear power plants in France

Today, nuclear energy is the main source of electricity in France and accounts for 77% of all France's energy production. France has 58 industrial nuclear reactors with a total capacity of 63.1 GW. France is ranked second in the world after the United States in terms of the amount of energy produced by nuclear power plants. France has a wholesale and retail electricity market. Transmission and distribution of electricity are monopolistic activities, as opposed to production and marketing.

In the last decade, the French energy system has been characterized by stable electricity production and consumption. However, in 2018, the production volume of increased at a ten year record rate, 3.7% and amounted to 548,6 TWT×h, Electricity consumption remained at 474 TWT×h for the sixth consecutive year (Eurostat 2018). Figure 5-2 shows negligible greenhouse gas emissions from energy industries in France.

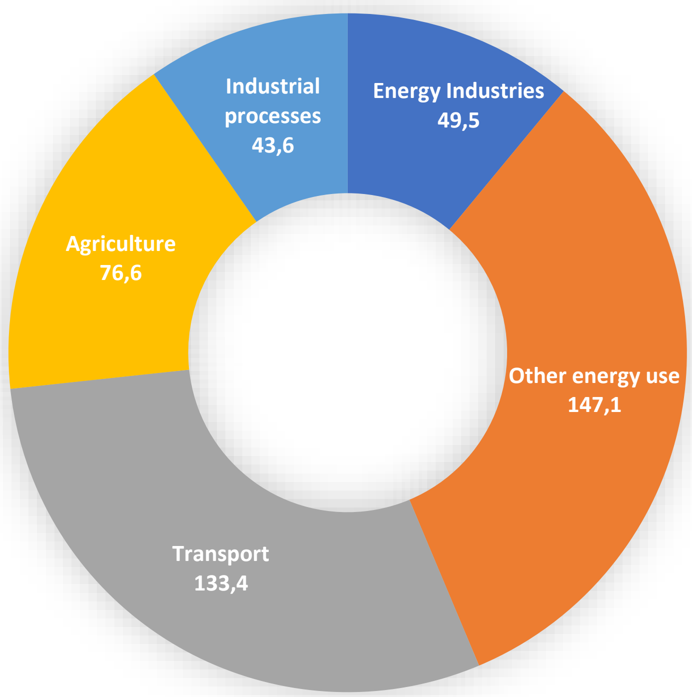

Figure 5-2 Sectoral greenhouse gas emissions in France in million tons CO2-eq, 2017 (Source: EEA)

Taking into account LCA default emission factors from nuclear power plant and given amount of electricity produced for gas transportation we calculated CO_2 Emission intensity, which are shown at the table 5-2.

Table 5-2 CO_2 emission intensity, kg/Sm^3 o.e.

Scenario	Transportation chain	LCA default emission factors, ton-CO_2/MWh	CO2 Emission intensity, kg/Sm3 o.e.
Scenario 1.2	Snøhvit – Europipe II	0,008	4,1
Scenario 2.2	Snøhvit - Langeled	0,008	3,8
Scenario 3.2	Snøhvit - Zeebrugge	0,008	8,6

Scenarios 1.3, 2.3, 3.3 – import of electricity generated at coal power plants in Poland

Today, there are more than 300 power plants in the EU with 738 coal-fired power units operating in them. They are not evenly distributed, but in general, coal and brown coal provide a quarter of all electricity generation in the EU. Coal-fired power plants are considered one of the most environmentally "dirty," while the environmental policy of the European Union involves reducing greenhouse gas emissions into the atmosphere. In this regard, some European countries (Belgium, Austria, Portugal, Denmark, Finland, Sweden, France, and Great Britain) reduced coal-fired power plants with other sources of electricity. However, other EU countries (Ireland, the Netherlands, Italy, Croatia, Slovenia, and Slovakia), pay less attention to the issue of coal combustion in electricity production and similar processes are developing at a slower rate.

Poland is the largest coal producer in Europe. About 80% of all electricity in the country is produced by coal-fired power plants. Polish Government stipulates decommissioning of 12 GW of old capacities by 2030 in the Energy Policy Plan (Polish Ministry of Energy 2009).

On the other side, the Polish Ministry of Energy plans to modernize or build power units of coal-fired power plants with a total capacity of 11.9 GW, therefore the outgoing coal capacity will be replaced by new coal-based energy. The volume of electricity production in 2017 was 171 TWh of electricity consumption of 140 TWh.

Figure 5-10 shows sectoral greenhouse gas emissions in Poland, where we can see that emissions from energy industries play a crucial role for the total volume of emissions.

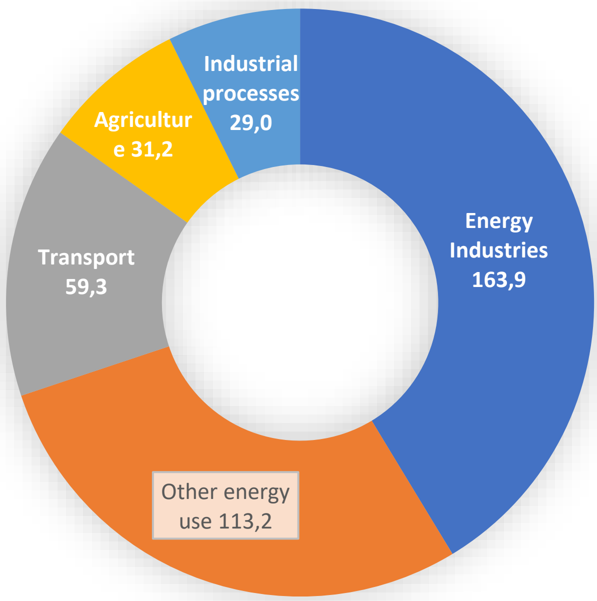

Figure 5-3 Sectoral greenhouse gas emissions in Poland in million tons CO2 equivalent, 2017 (Source: EEA)

Considering LCA default emission factors from coal power plant and given amount of electricity produced for gas transportation we calculated CO_2 Emission intensity, which are shown at the table 5-3.

Table 5-3 CO_2 emission intensity, kg/Sm^3 o.e.

Scenario	Transportation chain	LCA default emission factors, ton-CO_2/MWh	CO2 Emission intensity, kg/Sm3 o.e.
Scenario 1.3	Snøhvit – Europipe II	0,37	189,6
Scenario 2.3	Snøhvit - Langeled	0,37	175,8
Scenario 3.3	Snøhvit - Zeebrugge	0,37	397,8

Scenarios 1.4, 2.4, 3.4 – import of electricity generated at hydro power plants in Sweden

Sweden's energy policy is based on three main principles: sustainable development of the environment, free competition, and guaranteed energy supply. Sweden does not have its own hydrocarbon resources in the form of commercially significant deposits of oil, natural gas, or coal, but it has significant hydropower and forest resources. Sweden's energy policy is based on the drive towards renewable energy and environmental protection.

The volume of electricity production in 2017 was 160,5 TWh and the electricity consumption was 120 TWh. Most of the energy was sold through the spot market, Nord pool. Power generating companies provide reserve power for balancing electricity production and consumption based on an agreement with the system operator.

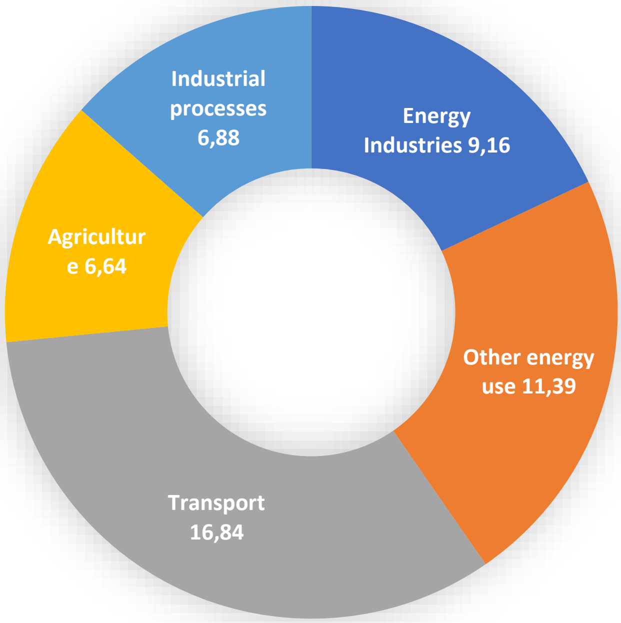

Figure 5-4 Sectoral greenhouse gas emissions in Sweden in million tons CO_2 equivalent, 2017 (Source: EEA)

Considering LCA default emission factors from hydro power plant and given amount of electricity produced for gas transportation we calculated CO_2 Emission intensity, which are shown at the table 5-4.

Table 5-4 CO_2 emission intensity, kg/Sm^3 o.e.

Scenario	Transportation chain	LCA default emission factors, ton-CO_2/MWh	CO2 Emission intensity from electricity generation, kg/Sm3 o.e.
Scenario 1.4	Snøhvit – Europipe II	0,006	3,0
Scenario 2.4	Snøhvit - Langeled	0,006	2,8
Scenario 3.4	Snøhvit - Zeebrugge	0,006	6,5

At the previous three tables 5-2, 5-3 and 5-4 we calculated the CO_2 emission intensity only from electricity generation. To find out the total CO_2 emission intensity, we should add the CO_2 emission intensity from upstream pipeline and LNG transportation. This type of emissions we took from Shaton (2017), where it was already calculated.

Table 5-5 Total emission intensity according to the type of power generation

Scenario	Transportation chain	Electricity generation	CO2 Unit Emission, kg/Sm3 o.e.	Annual volume of transported gas, Sm3 o.e./year	Annual CO2 emission, ton/year
Scenario 1.1	Snøhvit – Europipe II	Domestic – Gas turbine	110,99	11 836 432	1 313 726
Scenario 1.2	Snøhvit – Europipe II	Import – France – Nuclear Power Plant	26,2	11 836 432	310 115
Scenario 1.3	Snøhvit – Europipe II	Import – Poland – Coal Power Plant	211,6	11 836 432	2 504 589
Scenario 1.4	Snøhvit – Europipe II	Import – Sweden – Hydro Power Plant	25	11 836 432	295 911
Scenario 2.1	Snøhvit - Langeled	Domestic – Gas turbine	34,24	7 700 000	263 648
Scenario 2.2	Snøhvit - Langeled	Import – France – Nuclear Power Plant	13,8	7 700 000	106 260
Scenario 2.3	Snøhvit - Langeled	Import – Poland – Coal Power Plant	185,8	7 700 000	1 430 660
Scenario 2.4	Snøhvit - Langeled	Import – Sweden – Hydro Power Plant	12,8	7 700 000	98 560
Scenario 3.1	Snøhvit - Zeebrugge	Domestic – Combine Heat and Power Plant	286,2	4 500 000	1 287 900
Scenario 3.2	Snøhvit - Zeebrugge	Import – France – Nuclear Power Plant	88,6	4 500 000	398 700
Scenario 3.3	Snøhvit - Zeebrugge	Import – Poland – Coal Power Plant	477,8	4 500 000	2 150 100
Scenario 3.4	Snøhvit - Zeebrugge	Import – Sweden – Hydro Power Plant	86,5	4 500 000	389 250

Then, we found data on the annual volume of transported gas for the selected chains, which is also presented in Table 5-5. Using this data, we calculated annual CO_2 emission by multiplying for the CO_2 emission intensity. Based on the results of calculations, we have made an analysis and built diagrams for visual representation. Figure 5-5 illustrates the annual CO_2 emission for the Snøhvit – Europipe II transportation chain. Import of electricity from Poland is the highest source of CO_2 emission about $2500 \cdot 10^3$ ton/year, which is almost twice as big as emissions from domestic gas combustion in gas turbine. Using "green energy" resources such as Hydro Power Plant has almost the same impact as Nuclear Power Plant – about $300{\cdot}10^3$ ton/year.

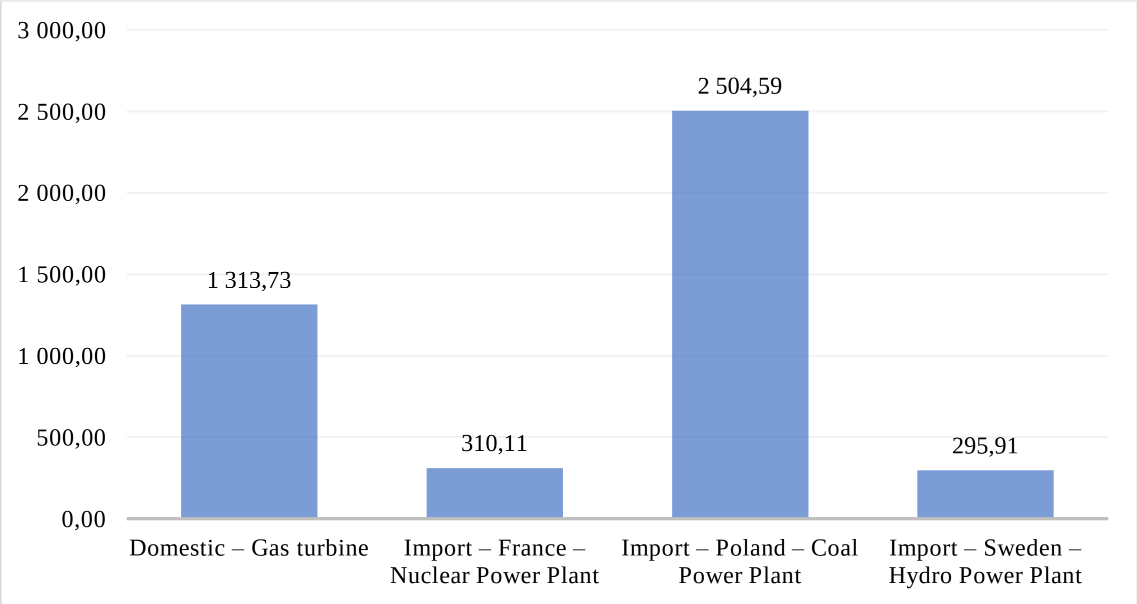

Figure 5-5 Annual CO_2 emission for Snøhvit – Europipe II pipeline chain, 10^3 ton/year

The next bar chart (Figure 5-6) deals with the Annual CO_2 emission for Snøhvit - Zeebrugge pipeline chain. It is easy to notice that Snøhvit – Europipe II and Snøhvit - Zeebrugge have almost the same carbon emission for each type of scenarios.

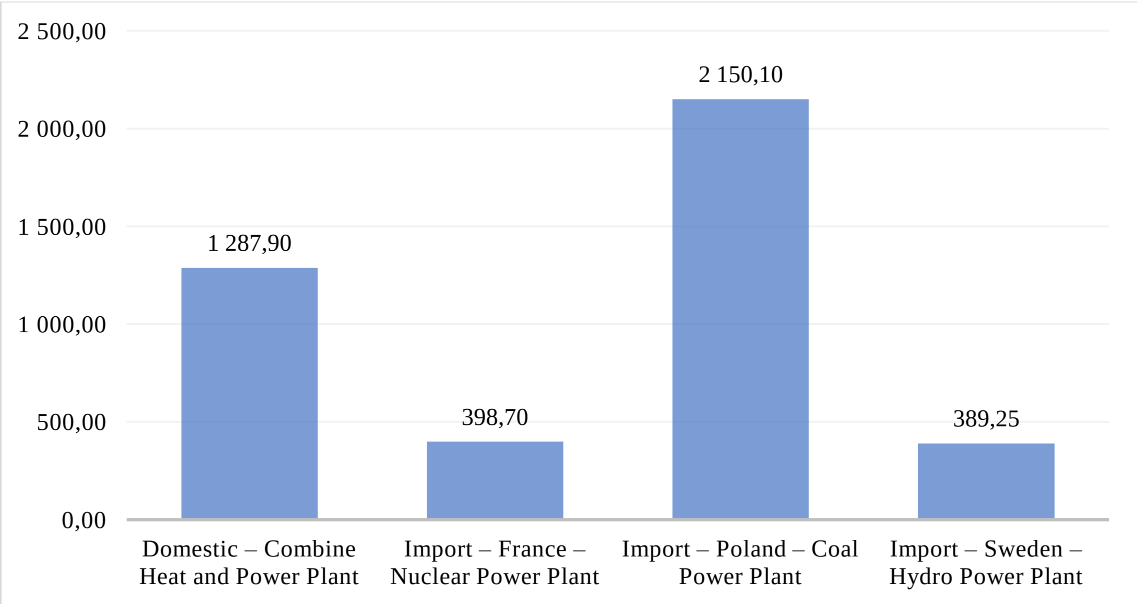

Figure 5-6 Annual CO_2 emission for Snøhvit - Zeebrugge transportation chain, 10^3 ton/year

Next Figure helps us to conclude that coal imported from Poland is the less desirable option for electricity generation considering the high level of CO_2 emissions.

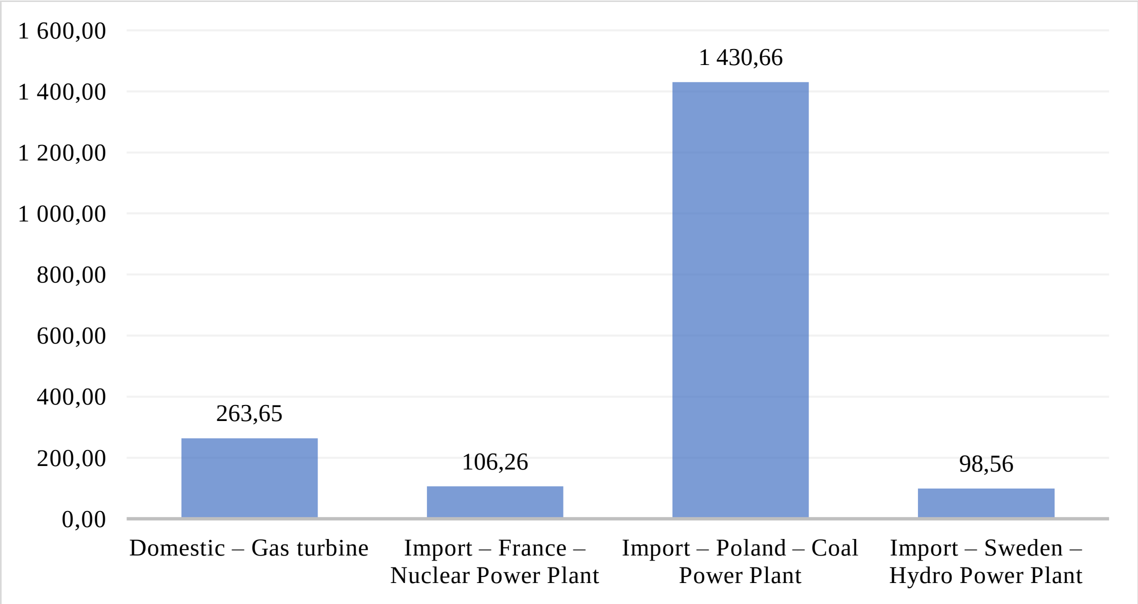

Figure 5-7 Annual CO_2 emission for Snøhvit - Langeled transportation chain, 10^3 ton/year

Based in Figure 5-8 we can say that Snøhvit – Langeled transportation chain is the most preferable option due to the minimal impact to the carbon footprint.

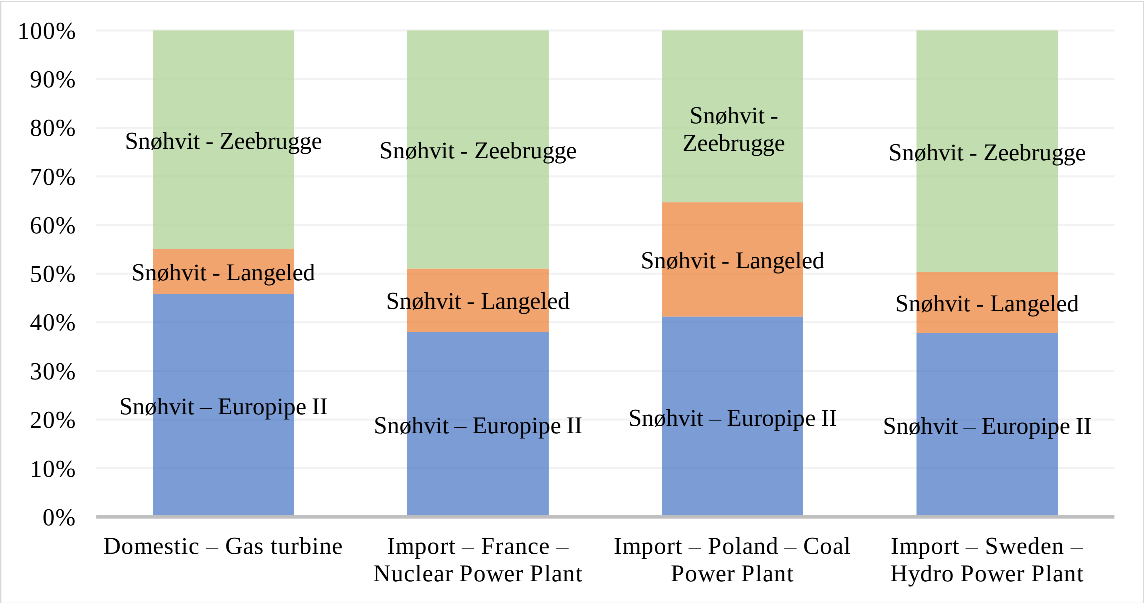

Figure 5-8 Share of annual CO_2 emission for each transportation chains, 10^3 ton/year

6 SOCIAL COST OF EXTERNALITIES OF THE BARENTS SEA GAS INFRASTRUCTURE

6.1 Putting a price on carbon emissions

Currently, the price which is paid by the petroleum companies on the NCS for a ton of emitted CO_2 is about 760 NOK (MPE, 2019). This price includes EU allowance price (260 NOK) and also the general tax equals to 500 NOK per ton of CO_2 emitted. In order to avoid double counting in our analysis we should subtract the costs which are already covered by the petroleum companies from our cost calculations. The obtained difference will result in the cost of the environmental externality:

$$SCC = \sum_{t=1}^{30} (A\_em) \cdot p \cdot (1 + r)^t - 30 \cdot (A\_em) \cdot (Q + T)$$

SCC – value of the environmental externality, billion NOK

A_em – annual emissions, ton/year

p – calculation price

t – year

Q – EU allowance price, NOK

T – CO_2 tax, NOK

30 years – analysis period

It worth noting that the price which is currently paid by the petroleum companies for a ton of emitted CO_2 could cover the social costs of CO_2 emissions in the short run. However, in the long run the marginal abatement cost would be much higher. Therefore, by conducting the calculations we will check how efficient is the use of current calculation price in the long run.

Table 6-1 Value of externality due to carbon emissions

Scenario	Electricity generation	CO2 Unit Emission, kg/Sm3 o.e.	Annual CO_2 emission, ton/year	Social cost of carbon (Bln NOK)	CO2 tax + quota (Bln NOK)	Value of externality (bln NOK)
Snøhvit – Europipe II						
Scenario 1.1	Domestic – Gas turbine	110,99	1 313 726	**40,2**	**30,0**	**10,2**
Scenario 1.2	Import – France – Nuclear Power Plant	26,2	310 115	**9,5**	**7,1**	**2,4**
Scenario 1.3	Import – Poland – Coal Power Plant	211,6	2 504 589	**76,6**	**57,1**	**19,4**
Scenario 1.4	Import – Sweden – Hydro Power Plant	25	295 911	**9,0**	**6,7**	**2,3**
Snøhvit - Langeled						
Scenario 2.1	Domestic – Gas turbine	34,24	263 648	**8,1**	**6,0**	**2,0**
Scenario 2.2	Import – France – Nuclear Power Plant	13,8	106 260	**3,2**	**2,4**	**0,8**
Scenario 2.3	Import – Poland – Coal Power Plant	185,8	1 430 660	**43,7**	**32,6**	**11,1**
Scenario 2.4	Import – Sweden – Hydro Power Plant	12,8	98 560	**3,0**	**2,2**	**0,8**
Snøhvit - Zeebrugge						
Scenario 3.1	Domestic – Combine Heat and Power Plant	286,2	1 287 900	**39,4**	**29,4**	**10,0**
Scenario 3.2	Import – France – Nuclear Power Plant	88,6	398 700	**12,2**	**9,1**	**3,1**
Scenario 3.3	Import – Poland – Coal Power Plant	477,8	2 150 100	**65,7**	**49,0**	**16,7**
Scenario 3.4	Import – Sweden – Hydro Power Plant	86,5	389 250	**11,9**	**8,9**	**3,0**

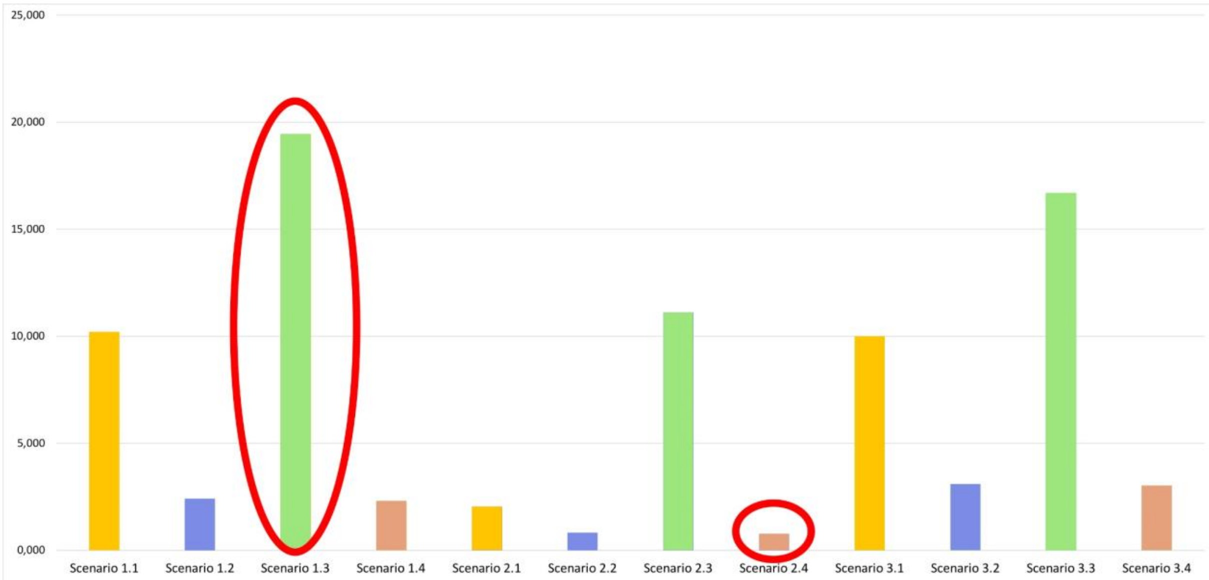

Figure 6-1 Value of externality due to carbon emissions

According to the obtained results there are no scenarios in which the social cost of carbon is fully compensated by the petroleum companies. The values vary significantly depending on the scenario of power generation. The highest value of the environmental externality – 19,4 billion NOK belongs to the pipeline solution powered with the electricity generated in the coal power plant, whilst the lowest – less than 1 billion NOK belongs to the pipeline solutions powered either by electricity generated in nuclear or hydro power plant.

6.2 Sensitivity Analysis

The main goal of sensitivity analysis is to estimate how sensitive the results which were obtained during the calculations of the social cost of carbon emissions performed throughout this thesis. As previously noted there may be considerable level of uncertainty about the assumptions which were made to perform the analysis. Such uncertainty refers to the choice of the appropriate value of calculation price, discount rate, analysis period and the accuracy of secondary data for annual carbon emissions.

1. Calculation price

In our research we used the calculation price equals to 524 NOK recommended by High-Level Commission on Carbon Prices (2017) in order to achieve the two-degree target. However, there is no consensus regarding the global calculation price for carbon emissions which should be used for CBA purposes. As it discussed in the previous chapter there exist a variety of approaches of determining the calculation price which vary from country to country. To estimate how sensitive our results to the value of calculation price we calculated the value of environmental externality by setting two alternative values for the calculation price. The first value is US 42 (365.2 NOK) per ton of CO_2 emitted which is based on three integrated assessment models and is recommended as a SCC in CBA of public measures in the US. The second value is US 90 (782 NOK) proposed by Pindyck (2019) in his research devoted to estimation of average value for social cost of carbon. The results are presented in the table below:

Table 6-1: Value of externality (bln NOK) depending on calculation price

	Scenario											
Price	Sc 1.1	Sc 1.2	Sc 1.3	Sc 1.4	Sc 2.1	Sc 2.2	Sc 2.3	Sc 2.4	Sc 3.1	Sc 3.2	Sc 3.3	Sc 3.4
365,2	-1,97	-0,46	-3,75	-0,44	-0,40	-0,16	-2,14	-0,15	-1,93	-0,60	-3,22	-0,58
524	10,20	2,41	19,45	2,30	2,05	0,83	11,11	0,77	10,00	3,10	16,69	3,02
782	29,97	7,07	57,14	6,75	6,01	2,42	32,64	2,25	29,38	9,10	49,05	8,88

As it depicted in the figure below the value of externality is quite sensitive to the value of calculation price. According to the obtained results under the value of calculation price less than 390 NOK the social costs of carbon emissions are fully compensated by the petroleum companies. However, under the values equal to 390 NOK and higher the value of externality grows significantly even with the small increase in carbon price.

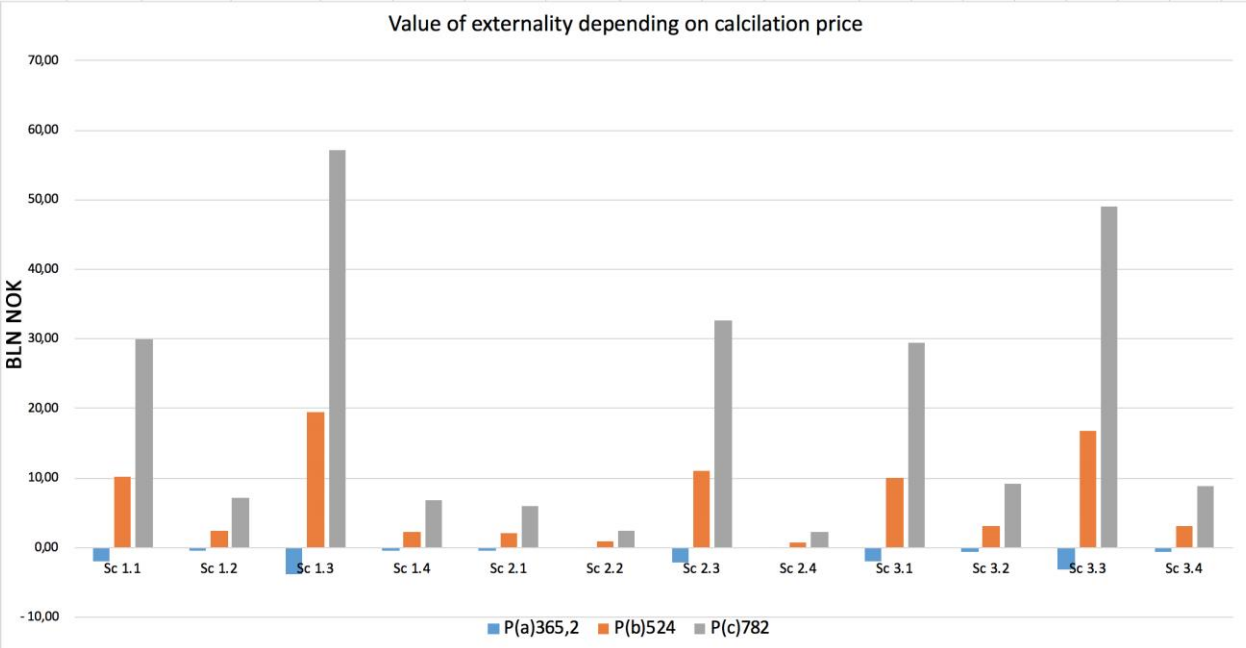

Figure 6-2 Value of externality depending on calculation price

7 DISCUSSION AND RECOMMENDATIONS

This chapter is the final part of the thesis. The first section addresses the discussion of the results obtained in Chapter 6. The limitations of the research are highlighted in the second section and finally the recommendations for further research are proposed.

7.1 Discussion of the results

Based on the information provided throughout this thesis the Barents Sea is the most promising area for the development of the petroleum activities on the NCS. According to Norskpetroleum (2019b) the Barents Sea contains 37% of the remaining Norwegian petroleum resources. However, the Barents Sea area is characterized by the lack of transport infrastructure which is required for sustainable operation activities. Within this thesis we considered two transportation options for the establishment of gas transport infrastructure in the Barents Sea. The first option is the pipeline transportation. It was considered two potential transportation chains with the same original point in Snøhvit but different destination points in Nyhamna and Karstø respectively. The expansion of the existing LNG facility at Melkøya by the construction of LNG train 2 was considered as the second potential transportation option. The operation of both pipeline and LNG plant are highly energy-consuming and therefore require reliable power supply system. There exist two power supply options. The first option is the use of natural gas as the primary source of energy. The second alternative is the use of electricity as the source of energy.

As it discussed earlier, the operation of gas transport facilities entails substantial environmental footprint caused by carbon emissions. However, the existing economic appraisal practice of gas infrastructure projects do not address the costs due to carbon footprint. Shaton and Hervik (2018) conducted the assessment of the environmental footprint of Polarled Transport. Authors obtained the cost of the environmental externality equals to 3.14 billion NOK. Based on the framework provided by Shaton and Hervik (2018) we conducted the assessment of the value of the environmental externality for potential gas transport options in the Barents Sea distinguished by the source of power supply. It is generally believed that the combustion of natural gas for power generation generates a significant amount of carbon emissions into the atmosphere compared to electricity consumption from the main power grid. However, it is usually overlooked that the electricity generation at electricity power stations is also associated with carbon emissions. The volume of carbon emissions generated by electricity power stations depends on the primary source which used for electricity generation. Whilst the emissions from hydro power station are negligible, coal power plants have significant environmental footprint.

The distinctive feature of the renewable energy sources as wind, solar and hydro is its high dependence on weather conditions. The major part of the electricity in Norway is generated by local hydro power stations. For now, the available hydro power resources in Norway are almost fully utilized. Therefore, the existing power stations would not be able to produce excess capacity to provide power supply for the potential new gas transport infrastructure in the Barents Sea.

Due to this fact in our research we considered the possibility of import of electricity from other countries. We examined three options of electricity import from countries which use different primary sources for electricity generation. Based on default emission factor for each type of power plants and given the required capacity for the operation of gas transport facilities we calculated the annual carbon emissions for each of the potential transportation chains distinguished by the source of power generation. Further, we put the carbon price on the corresponding emissions and calculated the cost of carbon emissions within the planning horizon.

By considering obtained results, we can conclude the following:

- The use of electricity generated by the coal power plant is less preferable alternative due to the most significant amount of carbon emissions and as a consequence the highest value of the social cost.
- The scenarios of energy supply from the hydro and nuclear power plants showed similar results. Values of the social costs of carbon obtained from these scenarios are 10 times less compared to the scenario with coal power plant.
- Scenarios which consider combustion of the domestic natural gas for power generation are more preferable than the import of electricity from coal power plants, but still less competitive compared to the scenarios considering nuclear and power plants.

As it discussed in sensitivity analysis the obtained results are highly dependent on the value of calculation price, discount rate, planning horizon and the accuracy of data used.

7.2 Limitations

This section devoted to the description of the main limitations and challenges, which occurred during the process of writing this thesis.

The first limitation was the availability of information regarding the potential gas transport infrastructure in the Barents Sea. Currently the number of studies on that topic is very limited or based on unproven assumptions. One of the main studies concerning our topic was the report on Barents Sea gas infrastructure provided by Gassco (2014). However, as the report was published 5 years ago, some of the findings may be already out of relevance.

The second limitation is the calculations of the environmental externality itself. We calculated only the value of externality due to the carbon dioxide emissions. However, by using the same framework the cost of other environmental impacts may be estimated. The most challenging task is to evaluate such impacts in monetary form since there is a lot of uncertainty regarding the actual consequences of these impacts. Moreover, as there are no perfect representations of the true values of calculation prices of environmental impacts, the determination of such values is susceptible to manipulations. Since we were limited in time, we concentrated primarily on impacts of carbon emissions.

The third limitation is that we determined the most preferable alternative only from the perspective of the lowest cost of environmental impacts. However, in order to identify the best alternative from socio-economic perspective, the complete cost benefit analysis should be conducted.

The research embraces a broad range of research areas including economics, climate science and green logistics and may become a basis for the future research in each of these areas. The possible opportunities for the future research are described in the final section.

7.3 Recommendations for further research

The subject, which we addressed gives an opportunity for a variety of future research. As a first option we can suggest to conduct a comprehensive cost benefit analysis considering one or more aspects of the investment decision. Moreover, due to the fact, that our timeframe was limited we focused particularly on the CO_2 emissions, but it is worth to monetize all relevant impacts. For example, CH_4 emissions across the value chain of natural gas cause significant ecological effect to the environment.

Another issue that can be further elaborated in more details is capacity in existing pipelines. Taking into account required pipeline capacity for Barents Sea Gas infrastructure future researchers can investigate possibility of usage existing pipelines.

Existing literature offers numerous options for carbon price assessment. OECD (2018) gives an overview of the existing approaches of estimation of the social cost of carbon worldwide. A profound comparative analysis of different carbon price paths may be regarded as a further research.

Aspects, such as solar, geothermal and shale gas were ignored in our research as a sources of electricity, therefore as well can be considered further.

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