

Katerina Shaton

**Essays on upstream gas transport  
infrastructure planning and  
appraisal**



**Molde University College**  
Specialized University in Logistics

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# Essays on upstream gas transport infrastructure planning and appraisal

Katerina Shaton

A dissertation submitted to  
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## Preface

This dissertation was prepared in Molde University College – Specialized University in Logistics in partial fulfilment of the requirements for acquiring the PhD degree in Logistics. The study was conducted during the period from July 2011 to January 2017 under the main supervision of Professor Arild Hervik from Molde University College. Professor Svein Bråthen from Molde University College and Dr. Maria Sandsmark from Møreforsking have been co-supervisors.

This thesis consists of an introductory chapter and four articles, each considering a certain aspect of the upstream gas transport infrastructure planning and appraisal. In particular, this research project deals with socio-economic appraisal of gas infrastructure development, including values of flexibility in pipeline investments and environmental externalities of gas transportation. The research is based on the practice and empirical data from the Norwegian gas transport sector.

This research has been funded by GasROR IKS, this support is greatly acknowledged. During the research period I was employed by Molde University College.

The evaluation committee for this thesis is composed of Professor Kjetil K. Haugen from Molde University College, Molde, Norway, Professor Kåre P. Hagen from the Norwegian School of Economics and Business Administration, Bergen, Norway, and Professor Roger Vickerman from University of Kent, Canterbury, the UK.



## Acknowledgements

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I also sincerely thank my co-supervisors: Professor Svein Bråthen, who was always helpful when everything seemed especially hopeless, and Dr. Maria Sandsmark for her constructive criticism and attention to details.

It would be difficult to overestimate the importance of my research visits to Gassco, where I had an opportunity to study the practice of gas transport infrastructure planning and operating from inside. I especially thank Thorbørn Svendsen and Sten Arve Eide for patiently answering hundreds of my questions and giving fruitful comments regarding the relevance and applicability of my research. The financial support from Gassco on the last part of the research period and the opportunity to continue my research work after the PhD period is also greatly acknowledged.

I highly appreciate many useful and inspiring discussions I had with my colleagues at Molde University College and fellow PhD students, who shared with me the pains and joys of the research endeavour. I would especially thank Professor Irina Gribkovskaia for all her help and precious advices during my years in Molde.

I would also thank my friends in Belarus, who managed to remain them disregarding my busyness (i.e. inattentiveness), and my friends in Norway, who opened this magic country to me and taught to enjoy its beauty even in the darkest time, both of the year and of the research period.

Finally, I thank my parents for their love and faith in me, tireless prayers and constant encouragement.

*'Unless the Lord builds the house, the workers labour in vain'  
(Psalm 127:1)*

Katerina Shaton,

Molde, June 2017



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## Introduction

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# 1 Motivation

Norway is the third largest gas exporter in the world. In 2015, exports of natural gas reached NOK 220 676 million, which is 26.4% of Norway's total exports (Statistics Norway, 2016). A necessary condition for a well-functioning gas market is an available and efficient transport infrastructure. The gas transport infrastructure on the Norwegian continental shelf (NCS) is represented by a network of pipelines with a total length of 8,300 km, which links gas fields offshore with processing plants on the mainland and with receiving terminals in France, Germany, Belgium and the United Kingdom (UK). About 5% of Norwegian gas is exported in liquid form by sea-going liquefied natural gas (LNG) tankers to Europe, Asia, and North and South America (Norwegian Petroleum Directorate, 2016).

Development of the existing pipeline network started in the 1970s, when a gas transportation solution was required for the giant Ekofisk discovery. The result was the 443 km-long Norpipe, which connects the field with the Norseas Gas Terminal at Emden in Germany. This was the first pipeline to deliver Norwegian dry gas to European consumers in 1977. Since then, the transport system has been in constant development. From separate field-dedicated solutions, it emerged into an integrated network that serves most of the fields on the NCS and ensures reliable and cost-efficient delivery of gas to Europe.

The use and development of the gas transport infrastructure on the NCS is organised around three cornerstones: ownership, operatorship and regulation. The framework for all Norwegian petroleum activities is determined by the Storting (the Norwegian parliament). Based on the petroleum activities act (Petroleum Act<sup>1</sup>), and the associated regulations (Petroleum Regulations<sup>2</sup>), the Ministry of Petroleum and Energy executes all regulations. After a major reorganisation of the petroleum sector in Norway in 2001, most of the gas transport systems were merged into a joint venture called Gassled, which became the formal owner of the transport system. In order to ensure non-discriminatory third-party access to the Gassled transport system, an independent system operator was appointed, the state-owned company Gassco AS.

Gassco plays several roles that are divided into two groups: normal and special operatorship. The tasks that are carried out on behalf of the system owners, in accordance with the operator agreement, are usually referred to as normal operatorship. These include operating the infrastructure in accordance with the Petroleum Act, as well as health, safety and environmental legislation. Special operatorship responsibilities include transport capacity allocation, system operation and the development of the gas transport system. These responsibilities are directly assigned to Gassco by the Petroleum Act (Section 4-9) and the Petroleum Regulations (Chapter 9), and are carried out on behalf of all system users. According to the capacity allocation task, Gassco collects data on the spare capacity available in the system and holds booking rounds twice a year, where eligible shippers can request spare capacity for medium and long terms. On a daily basis, Gassco handles requests for additional capacity for short terms. The allocated capacity can be transferred between the shippers bilaterally in the secondary capacity market, which is also administered by Gassco.

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<sup>1</sup> Act relating to petroleum activities (the Petroleum Act), 29 November 1996, No. 72

<sup>2</sup> Regulations to the Act relating to petroleum activities, 27 June 1997, No. 65.

System operatorship represents Gassco's main daily activities: dispatching of the gas fields, coordination of gas flows in the network, and balancing the volumes fed into the system and taken out of the system. Gassco charges tariffs for access to the Gassled transport system. The tariffs are stipulated by the Ministry of Petroleum and Energy, based on a formula provided in the tariff regulations.<sup>3</sup> The tariff consists of two parts: an operating element and a capital element. The operating element covers the costs of operating the transport system, while the capital element covers the investment costs made by the owners. The existing tariff system ensures that the returns in the gas sector are derived from gas extraction and production, and not from transportation. At the same time, the tariffs should provide a reasonable return on investments to the infrastructure owners (Petroleum Regulation, Section 63).

Regarding the development of the transport system, Gassco assumes the role of coordinator, or 'architect', of the network's expansion. Gassco operates on a 'no profit no loss' basis and does not invest in infrastructure projects; however, the company plays an active role in investment planning. Thus, Gassco contributes to the comprehensive development of the transport system by considering new infrastructure projects from the perspective of long-term value creation in the gas sector. In this context, both the gas from the fields that triggered the development and the potential volumes that may come on stream later are taken into consideration.

The relationships between regulation, ownership and operatorship of the Norwegian gas transport system are schematically represented in Figure 1.1.

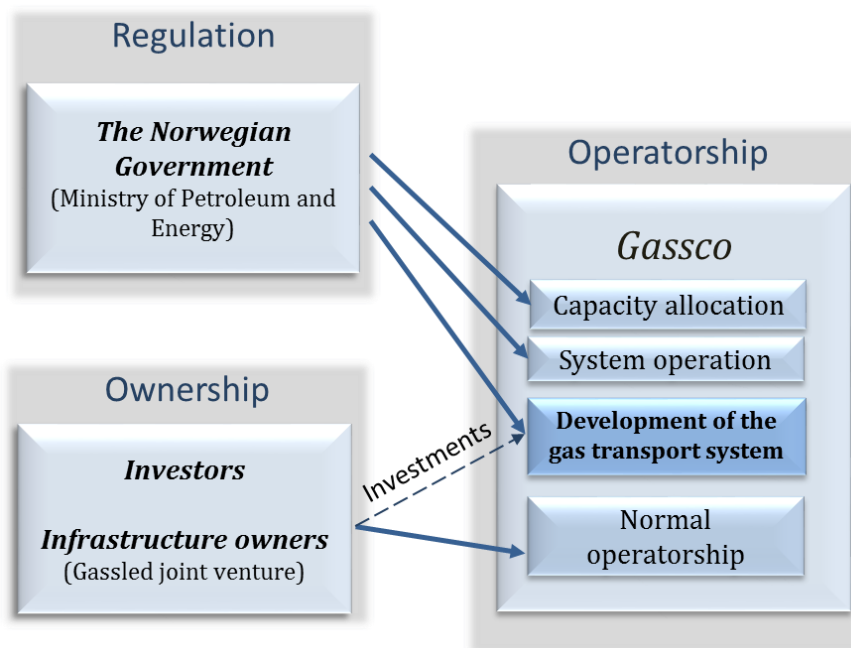


Figure 1.1 Main parties involved in gas transport infrastructure development

Development of the transport system is a particular aspect of this structure, because development of a new infrastructure is financed by commercial companies, but regulated by the government through a license system and regulated tariffs. Consequently, the interests of the commercial companies undertaking the investments and the objectives of the government may not always coincide. The particular role of the system operator is to balance these

<sup>3</sup> Regulations relating to stipulation of tariffs, etc. for specific facilities, 20 December 2002, No. 1724.

interests and suggest solutions that correspond to the needs of shippers, provide a reasonable expected return to the investors, and contribute to the long-term welfare, thereby maximising the goals of the state. The conflicting interests of the parties involved and the resulting challenges of infrastructure planning and appraisal are the focus of this research project.

Figure 1.2 depicts an understanding of the decision-making process used throughout this thesis regarding new infrastructure development in the Norwegian gas transport sector. In the annual plans, the system operator assesses the need for additional capacity with respect to exploration results and demand forecasts, and may initiate work on a new major infrastructure plan. In many cases, the planning for a particular transport facility is initiated by a company or a group of companies holding licences for petroleum production in the relevant area. The system operator is involved in the early stage of infrastructure planning. The operator performs its own assessments and makes recommendations regarding the technical aspects of the infrastructure facility, such as routing, landing points and capacity, but does not participate in investments and, therefore, cannot influence the final investment decision. When the concept is selected, one of the involved companies is appointed as the project's operator during the construction period. This company conducts the pre-engineering phase of the project and prepares the Plan for installation and operation of facilities for transport and utilisation of petroleum (PIO), which represents the application for a pipeline licence. It includes an installation section and an impact assessment section. The installation section is devoted to the technical and financial aspects of a project, while the impact assessment focuses on the consequences of the project implementation (installation and operation) on the environment, natural resources and society as a whole.<sup>4</sup> The basis for the impact assessment is an established study programme. Both the proposed study programme and the impact assessment are subjected to a public consultation. Based on the installation section and the impact assessment, as well as the consultation statements, the Ministry of Petroleum and Energy draws up a draft proposition for the Parliament or a Royal Decree, which is submitted to the relevant authorities, i.e. the Ministry of Labour, the Norwegian Petroleum Directorate and Gassco, for consultation. The government then submits the case either to the Parliament or to the King in Council, depending on the size of the investment.

A particular aspect of the planning process is concept selection. The circular arrows in Figure 1.2 depict the tight collaboration and negotiations between the involved petroleum companies and the system operator at the stages of feasibility and conceptual studies. At these stages, potential conflicts between the goals of the authorities and those of the commercial companies can arise. Profits maximising interests of commercial companies would advocate the fastest and cheapest solution, i.e. an LNG solution or a pipeline in the exact capacity needed to transport gas from the fields in question. The system operator, in turn, considers the project from the network perspective, suggesting solutions with regard to market flexibility, reliability of supply and future infrastructure development. A pipeline solution is characterised by high economies of scale in investments, meaning low additional costs to establish overcapacity, which presents the potential for less costly expansion and the connection of new transport facilities in the future. The availability of a transport solution with spare capacity incentivises exploration in the region and reduces the cost threshold for the development of marginal fields. However, in light of a high required rate of return in the industry, delaying the investment decision or tying up capital in long-term low-return infrastructure investments above the needed capacity, are considered losses by a commercial company. The chosen solution is a

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<sup>4</sup> Guidelines for plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilisation of petroleum (PIO). The Norwegian Petroleum Directorate, 4 February 2010.

consensus between short-term profit maximising objectives of commercial companies and long-term value creation maximising goals advocated by the system operator.

The scope of the system operator’s responsibilities does not include assessing the impacts of an infrastructure project on the environment and society. The assessment of these effects is performed by a commercial company after the concept is selected. In order to ensure due attention to these effects, the relevant authorities evaluate the impact assessments. However, the existing appraisal procedures might disregard important socio-economic impacts at the concept selection stage.

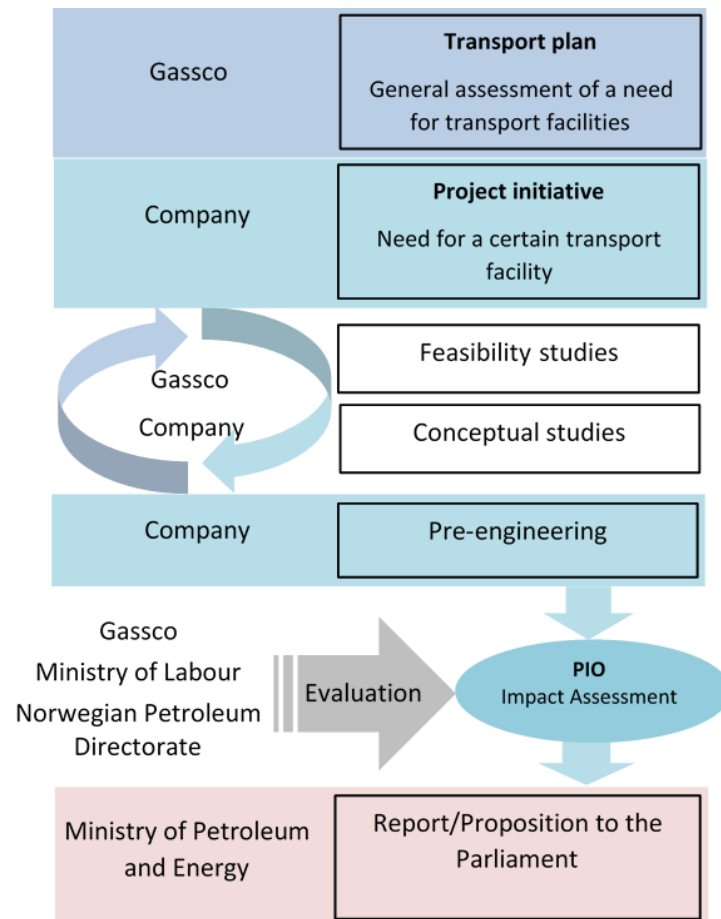


Figure 1.2 Gas transport infrastructure planning process

The existing regulatory framework was organised with the intention of balancing the commercial interests of petroleum companies with socio-economic considerations. The involvement of the authorities at all stages of investment planning and appraisal is required to ensure this balance. However, the existing planning and appraisal system in the gas transport sector has room for improvement. The purpose of this thesis is to suggest analytical approaches to address the challenges arising in the investment planning and appraisal in the gas transport sector.

## 2 Research objectives

Since the very beginning of the petroleum era, the Norwegian policymakers shared the view that the resources belong to the nation, and the development should benefit the whole society, including future generations. This goal is clearly formulated in the Petroleum Act, Section 1-2: ‘. . . Resource management of petroleum resources shall be carried out in a long-term perspective for the benefit of the Norwegian society as a whole. . .’. The Norwegian model of petroleum sector governance is considered ‘canonical’ and is used as a benchmark by development institutions in countries with hydrocarbon resources (see, e.g., Thurber et al., 2011; Lund, 2014). Various implications of the existing regulatory framework are covered in the academic literature. For instance, Hunter (2014) and Åm and Heiberg (2014) discuss how the Norwegian regulatory framework incentivises more effective oil and gas recovery. Holden (2013) and Mohn (2016) analyse Norway’s resource wealth management and fiscal policy. Extensive research exists on the impacts of petroleum activities on the environment, natural resources and Norwegian society. For example, Bakke et al. (2013) consider the environmental impacts and the risks associated with the discharge of produced water and drill cuttings from offshore oil and gas platforms. Blanchard et al. (2014) discuss the conflicts arising from routine petroleum operations, which impact marine ecosystems, and the uncertainties regarding the scale of the associated impacts. Gavenas et al. (2015) investigate the influence of a field’s age and size, the share of oil and in total reserves, and the carbon prices on CO<sub>2</sub>-emission intensity of Norwegian oil and gas extraction.

However, the aforementioned literature does not distinguish gas transportation in the general framework of the petroleum activities on the NCS. Nevertheless, the development and operation of the gas transportation network on the NCS receives considerable attention from the research community. The most widely used approach to analyse gas transport infrastructure development and operation is linear optimisation modelling. Among the first to explore the gas transportation problem is a study by Nygreen et al. (1998). The authors present a multi-period mixed integer programming model for long-term planning of petroleum production and transportation, with the emphasis on project scheduling. More recent examples include the paper by Rømo et al. (2009), which presents a decision support tool, GassOpt, also based on a mixed-integer program, optimising the network configuration and routing. Nørstebø et al. (2010) develop extensions to this model, which are related to the modelling of gas processing and compression, and analyse their impacts on system optimisation and operation. Hellemo et al. (2012) propose an investment analysis tool for natural gas infrastructure development, based on a deterministic mixed-integer linear program. The model extends the previous models by adding the pressure flow relationship and gas quality into the transportation system. Midthun et al. (2015) expand this model by allowing for continuous investment decisions, regarding the capacity of pipelines, processing facilities and compressors. Fodstad et al. (2015) present a modelling framework for analysing the use of interruptible transportation services to improve capacity utilisation in the natural gas transportation network.

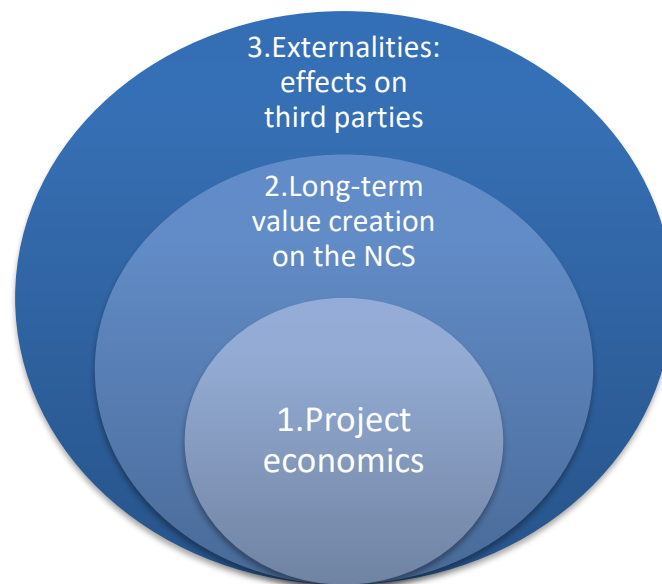
In addition, several studies use game-theoretic tools to analyse the interactions of parties involved in the development of upstream transport infrastructures. For example, Hagen et al. (2007) address the issue of optimal tariffs for natural gas transport. Sannarnes (2007) discuss how to design investment mechanisms to induce a socially optimal capacity increase in a gas transport network. Xu and Haugen (2008) investigate how the restructuring of the Norwegian gas transport system in 2002 changed the incentives of petroleum companies to invest in a new pipeline infrastructure.

In the research mentioned above, the effect of the development and operation of the gas transport infrastructure on Norway’s social welfare is reflected through maximisation of the total surplus created in the industry. However, such an approach does not capture all the



relevant socio-economic impacts, especially externalities of the infrastructure projects. A review of the existing literature reveals a gap: infrastructure development decisions are predominantly studied using optimisation techniques, while the related socio-economic aspects are mainly studied within a wider framework of petroleum activities on the NCS. This thesis contributes to filling this gap by emphasising the socio-economic perspective of gas transport infrastructure development in the Norwegian gas transport sector.

An in-depth study of the regulatory framework and a broad survey on the appraisal of infrastructure projects in the Norwegian gas transport sector determined the scope of this research project. Three levels can be defined in the investment problem in the upstream gas transport sector (Figure 2.1). At the core of an infrastructure project is the need for a gas company to establish a transportation solution for certain gas discoveries. At this level, the new transport infrastructure is considered part of the field development projects. At the second level, the new infrastructure facility is considered part of the network, with regard to the long-term value creation in the sector. The third level represents the social welfare perspective, which includes the impacts on third parties, i.e. those who are not directly involved in gas production and transportation.



*Figure 2.1 Levels of the investment problem in the gas transport sector*

The primary objective of this thesis was to develop a framework for comprehensive project appraisal in the upstream gas transport sector, which would internalise the economic impacts occurring at the three levels of the investment problem identified above. This objective is primarily addressed in Paper 1. The paper established the framework of the research project and raised several questions, which required a separate investigation. One such question was how to estimate the value of flexibility in gas pipeline investments within the comprehensive socio-economic analysis of an infrastructure project. The flexibility provided by excess pipeline capacity has long-term value for value creation in the gas sector, and is one of the most important aspects considered at the second level of the problem defined in Figure 2.1, but is disregarded on the project level. This issue is addressed in Paper 2. Another natural question, which is unavoidable in the context of investment planning, was the structure of the investment incentives in the sector. Paper 3 presents my understanding of this structure and investigates the relationship between the current tariff regime and the investment decisions taken in the sector. This paper investigates the relationships between the actors at the first and second

levels of the structure in Figure 2.1, and the particular role of the system operator in infrastructure development. Paper 4 contributes to the third level of the investment problem by investigating in detail the environmental externalities of gas transportation.

### 3 Summary of the papers

Paper 1, “**Economic appraisal in the Norwegian gas transport sector**”, investigates how the cost-benefit analysis (CBA) methodology can be applied to the infrastructure development decisions in the upstream gas sector. We consider the main methodological aspects of CBA: the scope of analysis, the stakeholders, relevant impacts and uncertainty. We focus especially on the environmental externalities and the use of real options in CBA for valuations of flexibility in transport infrastructure investments. In order to investigate what CBA can contribute to the existing appraisal practice, we present a case study of the appraisal of a recent infrastructure project in the Norwegian gas transport sector, where the proposed method was used as a benchmark. The case study shows that some important socio-economic impacts can be missing or may not be evaluated explicitly in the existing appraisal practice. The proposed method provides a framework for comprehensive and systematic analysis of infrastructure projects, thereby providing decision support for concept selection.

The paper is co-authored by Arild Hervik. A previous version of this paper was presented at the 27th annual NOFOMA (The Nordic Logistics Research Network) Conference, “Towards Sustainable Logistics and Supply Chain Management”, in Molde, Norway, 3–5 June 2015, and published in Jæger, B. (2015). NOFOMA 2015: Post Conference Proceedings, Molde, 3–5 June 2015, Nordic Logistics Research Network, ISBN: 978-82-7962-207-9. The present version of the paper has been submitted to Energy Strategy Reviews.

Paper 2, “**Value of flexibility in gas pipeline investments**”, develops one of the directions established in Paper 1 by focussing on the valuation of the flexibility in transport infrastructure investments and its importance for the decision making involved in infrastructure development. Investments in upstream gas transport pipelines are characterised by significant economies of scale: there is a low additional cost to establish capacity in excess of the committed volumes. The excess capacity provides flexibility for cost-efficient expansions of the transportation system if new discoveries are made in the future. The flexibility to expand the transportation network can be regarded as an option, which can be exercised in the event of new discoveries and when market conditions are favourable. The real options analysis provides a means to estimate the monetary value of flexibility in investments. In this paper, I review the existing approaches to real options valuations and identify those that can handle both market uncertainty and project-specific uncertainty, which are inherent to pipeline investments. An approach based on binomial matrices is chosen and applied to a simulated example of a pipeline project valuation. The paper also demonstrates how the value of flexibility provided by excess pipeline capacity can be used by a public decision maker in the evaluation of infrastructure projects in the Norwegian gas transport sector.

A previous version of this paper was presented at the 20th Conference of the International Federation of Operational Research Societies (IFORS) in Barcelona, Spain, 13–18 July 2014. The paper was presented at the Hamburg International Conference of Logistics (HICL) in Hamburg, Germany, 24–25 September 2015. A shorter version is published in Kersten, W., Blecker, T. and Ringle, C.M. (2015). Innovations and Strategies for Logistics and Supply Chains. epubli GmbH, Berlin, ISBN: 978-3-7375-7805-9.

Paper 3, “**Incentive problem in upstream gas transport infrastructure development**”, investigates the interactions between the main parties involved in the infrastructure development. If the first two papers are devoted to the appraisal of gas transport infrastructure investments, this paper analyses the incentives under which these investments are undertaken. The objective of this paper is to build an analytical framework, which helps to structure and understand the interactions between the main parties involved in infrastructure investments under the existing tariff regime. Special emphasis is placed on the relative advantages of the LNG and pipeline solutions: the price premium due to the destination flexibility of the LNG and economies of scale in the pipeline investments, which enable over-dimensioning of the pipelines with regard to future tie-ins. The interactions of the market players involved in upstream gas transport infrastructure development are investigated with the help of a game theoretic approach.

This paper was presented at the ITQM (Information Technology and Quantitative Management) conference in Moscow, Russia, 3–5 June 2014. A shorter version is published in *Procedia Computer Science* (2014), 31, pp. 413–422, doi: 10.1016/j.procs.2014.05.285.

Paper 4, “**Environmental footprint of gas transportation: LNG vs. pipeline**”, addresses one of the questions raised in Paper 1, which is related to the environmental externalities of infrastructure projects in the gas sector. The purpose of this paper was to estimate and compare the emissions to air caused by the extraction, processing and transportation of natural gas delivered from the NCS to markets via pipelines or in liquid form as LNG. Special consideration is given to the analysis of the environmental footprint of different pipeline chains depending on their configurations. The analysis substantiates the environmental superiority of pipeline chains over LNG-based chains. However, the comparative analysis of 10 pipeline chains highlights the significant variability of the environmental performance of pipeline transportation. The isolated analysis of the transportation segment of the value chains also confirms the superiority of pipeline transportation over LNG. In order to investigate the environmental aspect of gas transportation in light of the infrastructure development decisions on the NCS, we also separately consider the domestic parts of the transportation chains.

This paper is co-authored by Arild Hervik and Harald Hjelle. The paper was presented at the 39th conference of the International Association of Energy Economics (IAEE), in Bergen, Norway, 19-22 June 2016. It has been submitted to the *Energy Journal*.

## 4 Further research

**Paper 1.** The paper establishes a theoretical basis for CBA in the gas transport sector; however, a practical implementation of CBA requires additional research. One of the most important issues is the definition of an appropriate social discount rate for the analysis, which would reflect specific risks attributed to the petroleum sector. In the paper, we used the discount rate recommended for the socio-economic analysis of an ordinary public measure in Norway (NOU 2012:16). However, in gas transport infrastructure investments, the projects are funded by private capital, and this should be reflected in the choice of discount rate (Vickerman, 2007). An interesting aspect is that part of the capital used for financing the infrastructure investments is provided by petroleum companies that are partially or totally state-owned. It adds a perspective of public-private partnership to the problem and offers an interesting direction for further research.

**Paper 2.** The purpose of this paper was to consider how the real options framework can be used for valuation of excess pipeline capacity. As a point of departure, only one type of option

is discussed, i.e. the option to expand the system up to full capacity of the pipeline in question. In practice, possibilities exist to expand the system step-wise by new tie-ins of different sizes, representing compound options. Options to expand represent strategic flexibility; however, excess pipeline capacity also provides some operational flexibility. For example, spare capacity in pipelines can be used as line-pack storage, which becomes an important back-up mechanism for gas producers to deliver contracted volumes in the event of interrupted production at platforms. In addition, options can be provided by compressor configurations and possibilities to redirect gas via gas hubs. The availability of a variety of approaches to option valuation with different levels of complexity, especially regarding gas prices, offers wide opportunities for further research.

**Paper 3.** The paper proposes an analytical structure, which can be used for further analysis. The directions for further research are determined by the changing market conditions. Decreasing gas prices leads to the postponement of development decisions for many gas discoveries, and reduces the expected cash flow for gas transport infrastructure projects. The increased uncertainty over the prospects of recovering investment costs threatens the long-term development of the transport infrastructure on the NCS. Instead of participating in new infrastructure projects, gas companies may postpone field developments until spare capacity becomes available in the existing pipelines. In addition, companies may be reluctant to disclose full information about their discoveries and the associated need for the transportation service. A direction for further research could be to incorporate the asymmetric information into the model of gas transport infrastructure development.

**Paper 4.** The environmental aspect of gas production and transportation becomes increasingly important. A direction for further investigation may be to focus on the effects of carbon prices on the competitive position of Norwegian gas on the European market. Another research direction is prompted by the growing literature, particularly in the United States, on the methane leakage in gas production and distribution. Some studies (e.g., Alvarez et al., 2012; Schwietzke et al., 2014) claim that substituting new coal-fired power plants with new natural gas plants would result in short-term climate benefits only if the total net methane emission rates are less than 3%–4%. The transport of gas from the well to a distribution hub contributes significantly to the total methane leakage along the natural gas supply chain. This aspect may become important for the Norwegian gas sector as well in the near future.

## 5 Methodologies in logistics research

A research project of this type may be criticised for some methodological incoherence: how can a project that uses an economics methodology, which is mainly used to solve economic problems, be attributed to the discipline of logistics? A reasonable answer to this question requires a clear definition of logistics as a field of research. Several have attempted to give such a definition and identify the borders of the discipline (e.g., Stock, 1997; Arlbjørn and Halldorsson, 2002; Solem, 2003; Gammelgaard, 2004; Craighead et al., 2007; Bowersox; 2007). However, logistics is still a relatively young and unsettled field (Klaus, 2009), and due to its interdisciplinary nature and the broad variety of research perspectives and related methodologies, no widely acknowledged understanding of logistics as an academic discipline currently exists. According to Stock (1997), the disciplines that provide logistics with theories and methods include accounting, business/management, computing, economics, marketing, mathematics, philosophy, political science, psychology and sociology. Each of the root disciplines emphasises a particular area of logistics, leading to the difficulty of finding a consensus regarding the borders of logistics as an academic discipline.

From the perspective of my research work, I support the understanding of logistics as a field of research proposed by the German Logistics Association (Delfman et al., 2010, p. 58): 'Logistics is an application-oriented scientific discipline. It models and analyses economic systems as networks and flows of objects through time and space (specifically goods, information, money, and people) which create value for people. . . . The scientific questions of the discipline relate primarily to the configuration, and organisation of these networks and to the mobilisation and control of flows'. The authors define five cornerstones to understand logistics as an academic discipline:

- (1) *The network perspective*. The distinctive approach of logistics is its interpretation of economic systems as networks and of economic processes as flows of objects such as goods, information, people and money.
- (2) *Logistical inquiries on consecutive levels of aggregation*. Any logistical issue can be interpreted as networks of flows, which may be regarded further as part of a higher-level network.
- (3) *Interdisciplinarity of logistics*. Logistics uses methods from other disciplines, e.g. mathematics, engineering, economics and social sciences, but also develops them further. Interdisciplinarity is of central importance for logistics and is a central element of the logistics paradigm.
- (4) *Unity within a variety* of terminological, conceptual and methodological foundations of logistics, borrowed from various root disciplines, through the network model.
- (5) *Application orientation of logistics*. 'As an application-oriented science, logistics seeks to primarily address problems and research questions that are faced in real-world economic activities. . . . It aims to contribute proactively to an ever deeper understanding of such problems and to provide relevant solutions' (p. 61).

These five cornerstones help to identify the position of this research project in the discipline of logistics. This is an application-oriented study; therefore, there is no ambition to develop new theories, but rather to adapt the existing ones to the solution of practical problems in the infrastructure planning and appraisal in the Norwegian gas transport sector. For the objectives of this study, the methodological framework of economics has been chosen, which is one of the disciplines that contributes most to logistics (Frankel et al., 2008). The unit of analysis in this research project is the network of gas pipelines on the NCS. The network perspective is the unifying feature of the four articles constituting the thesis. This study focuses on the investment planning and appraisal problems faced by expansions of the Norwegian gas transportation system, which can be characterised as macro logistics on the country level. The Norwegian gas pipeline network can be regarded at a higher aggregation level, as an upstream part of the European gas transport system. Taking into account the emerging LNG sector in Norway, it can even be regarded as part of the worldwide gas network. Thus, research on a higher aggregation level may be another direction for further investigation.

To conclude the introduction, I submit that this thesis represents a humble attempt to contribute to the complex system of transport infrastructure planning and appraisal in the Norwegian gas sector by applying 'logistics thinking', which emphasises a holistic view of the problem. On the basis of empirical evidence, I have attempted to identify those aspects of the existing decision system that can be improved. In line with the methodological pluralism inherent to the discipline of logistics, I used different methodological approaches in each of the four papers, and combined theory and empirical data to suggest analytical approaches that can be applied in practice.

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**Paper 1**

**Economic appraisal in the Norwegian gas transport sector**

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# Economic appraisal in the Norwegian gas transport sector

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## Abstract

Investments in the upstream gas transport infrastructure are undertaken by commercial oil and gas companies on the basis of financial considerations. However, development decisions may have long-term effects on value creation in the gas sector and considerable external effects. This paper investigates how the methodology of cost-benefit analysis (CBA) can be applied to infrastructure development decisions in the upstream gas transport sector. The proposed method enables the possibility of a systematic appraisal of the values of flexibility in the infrastructure investments and environmental externalities of gas transportation. In order to investigate what CBA can contribute to existing appraisal practices, we present a case study of the appraisal of a recent infrastructure project in the Norwegian gas transport sector.

**Keywords:** *Upstream gas transport infrastructure; Economic appraisal; Cost-benefit analysis; Gas Pipelines; LNG*

# 1 Introduction

Relatively low coal prices and carbon prices currently challenge the competitive position of natural gas in the European power market. However, it remains one of the main energy sources in the European energy mix: 21.4% of total energy consumption was covered by natural gas in 2014 (Eurostat, 2015). With a higher carbon price in the long run, natural gas is expected to gain more importance in the energy mix, as a transition fuel to a carbon-free economy, due to its abundance, cost competitiveness and low carbon footprint (53.07 kg CO<sub>2</sub> per MBtu) in comparison to coal (95.35 kg CO<sub>2</sub> per MBtu) (EIA, 2016). While the importance of renewable energy has been increasing, natural gas plays an important role as a key provider of energy security. Against this backdrop, the EU has undertaken a number of initiatives to foster its natural gas market through the deployment of new cross-border infrastructure and the harmonization of market rules among its member states. In 2013, the European Parliament and Council adopted Regulation No. 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation), including electricity and gas transmission lines, electricity storage projects, underground gas storage projects and LNG terminals. The TEN-E Regulation establishes the principles relating to the identification of projects of common interest (PCI). PCIs should involve at least two member states, increase competition and enhance supply security and sustainability. Such projects would benefit from simplified licensing procedures, enhanced regulatory treatment and can receive financial support from the Connection Europe Facility. ENTSOG (European Network of Transmission System Operators for Gas) was appointed to develop an energy system-wide cost-benefit analysis (ESW-CBA) methodology for the selection of PCIs in the gas sector. This methodology, approved by the European Commission in 2015, evaluates the social welfare change at the aggregate EU level, instantiated by gas infrastructure projects. Focusing on the welfare of EU citizens, the methodology does not take into account the welfare change in producing countries (although an opportunity to evaluate the change in producers' profits is provided). Earlier publications on CBA in the gas sector (e.g. CERRE, 2011; DNV KEMA et al, 2013) also focused only on European consumers. This paper addresses the evaluation of the effects of infrastructure projects in the upstream gas sector on the welfare of a gas producing country, using the Norwegian natural gas sector as an example (see e.g. Holden (2013) for a comprehensive overview of the Norwegian policy in the petroleum sector).

The natural gas infrastructure on the Norwegian Continental Shelf (NCS) is represented by a system of platforms, processing plants, receiving terminals and an extensive network of pipelines with a total length of about 8300 km and a transport capacity of 120 billion Sm<sup>3</sup> per year. This transportation network connects gas producers on the shelf of Norway with markets in Germany, Belgium, the United Kingdom and France. About 95% of the gas produced on the NCS is transported via pipelines while the remaining five percent is shipped in liquid form by LNG (liquefied natural gas) carriers.

The development of a new infrastructure is a matter of negotiations between petroleum companies that finance infrastructure development and authorities responsible for regulating and coordinating petroleum activities on the NCS. Three levels can be defined in the investment problem in the Norwegian gas transport sector. At the core is the need for gas companies to establish a transportation solution for their gas discoveries. The decision criterion at this level is to maximize the expected profits from these discoveries. At the second level are the effects of the project on the remainder of the infrastructure network as well as value creation on the NCS. The independent system operator, the state-owned company Gassco, is involved in investment planning to ensure that these effects are taken into consideration. The third level includes the effects on third parties – those that are not directly involved in gas production and transportation – for example, environmental externalities. The evaluation of

these effects is left to gas companies, which apply for the statutory approval of projects. Evaluation of these impacts is not an integrated part of the economic appraisal of a project.

The purpose of this paper is to suggest an approach for a comprehensive appraisal of infrastructure projects in the upstream gas transport sector from the perspective of a public decision-maker. We adapt the standard CBA methodology (see e.g. Boardman et al., 2013) for investment appraisal in the upstream gas sector and discuss the specificity of the assessment of relevant costs and benefits in the Norwegian economic and institutional environment.

The paper is organized as follows. Section 2 discusses the methodological aspects of CBA implementation in upstream gas infrastructure projects. Section 3 presents a case study of the appraisal of a recent large infrastructure project on the Norwegian shelf using the proposed CBA framework as a reference point. Section 4 concludes.

## **2 The CBA methodology in upstream gas infrastructure projects**

### **2.1 Literature review**

A survey of the academic literature on appraisal methodologies reveals relatively few examples relating to the upstream gas transport sector. As petroleum infrastructure development is usually a matter of private capital investments, the existing literature discusses evaluation approaches common in commercial decision-making. Macmillan (2000) investigates whether there are links between the use of decision analysis in investment appraisal and decision-making by organisations and good business performance in the UK upstream oil and gas industry. Finch et al. (2002) investigate the extent to which formal and probabilistic appraisal and decision-making methodologies are adopted by companies in the UK upstream oil and gas sector. Dey (2002) addresses the problems of appraisal practice in the petroleum transport sector in India using the analytic hierarchy process as a technique. There is also a body of literature on environmental impact assessment in offshore hydrocarbon planning. Fidler and Noble (2012) provide a review of the research in this area and discuss the practice of strategic environmental assessment in the offshore oil and gas sector in Norway, Canada and the UK. The state of the literature reflects the industry practice, which can be characterized as a 'two-stage' system: petroleum companies evaluate projects from the commercial perspective, and public authorities monitor the potential consequences of these projects on the natural resources and environment. This paper suggests a wider approach measuring the total change in social welfare from the implementation of a project.

The CBA methodology is the most commonly used approach for economic appraisal of public decision-making in transport infrastructure appraisal (see e.g. Vickerman, 2007; Mackie et al., 2014). There is extensive academic literature on CBA applications in the evaluation of public roads investments (see e.g. Salling and Banister, 2009; Damart and Roy, 2009; Holz-Rau and Scheiner, 2011), civil aviation (see e.g. Bråthen et al., 2000; Jorge and Rus, 2004), and railways (see e.g. Vickerman, 2000; Van Wee, 2007). To our knowledge, there is no academic literature focusing on CBA in the upstream gas transport sector.

Norway has a long history of successful implementation of CBA in economic appraisal within healthcare, transport infrastructure, public defence and other sectors (see e.g. Nyborg, 1998; Odeck, 2010, for discussion). The practical CBA framework for national use is subsumed within

guidelines by the Norwegian Ministry of Finance (2005, 2010 and 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)) devoted to the methodology and application of CBA. The method presented in this paper corresponds with these documents in order to ensure the consistency of the economic appraisal in the gas transport sector with other sectors in Norway.

## 2.2 Scope of the analysis

In the existing appraisal practice, a transport infrastructure project is mostly regarded as an aspect of the corresponding development of a gas field. The proposed method considers the infrastructure project separately from the field development, focusing particularly on the transportation chain. Under the term 'transportation chain', we understand the way in which the gas, extracted at an offshore field, is delivered to the market. A typical pipeline transportation chain includes the transportation of rich gas (a mix of methane and other gaseous and liquid hydrocarbons) from an offshore field to a processing facility onshore and the transportation of dry gas (almost pure methane) further to markets in Europe. An LNG transportation chain consists of three segments: liquefaction, sea shipping and re-gasification. We consider processing, i.e. the physical process of separating the wellstream into various components (methane, condensate, natural gas liquids), as part of natural gas production, and hence, we leave this out of the scope of a transport infrastructure project analysis.

The development of a new transport infrastructure is triggered by a necessity to evacuate gas from proven gas reserves. However, the expected lifetime of a mid-sized gas field is 10–15 years while the technical lifespan of a pipeline is up to 50 years. An economic analysis of a transportation solution should internalize the economic impacts that occur after the initial fields cease production. There are no universal recommendations regarding the analysis period in a CBA as it depends on the nature of the project and the sector in question. Hagen et al. (2012) states that, analyses must reflect the period during which the measures under consideration are actually in use or of service to society, highlighting that the main principle should be to bring the analysis period as close to the lifespan as practicable. We consider 40 years as a reasonable analysis period for an infrastructure project in the upstream gas sector due to the high uncertainty over the resource base and the absence of reliable forecasts after this period. A typical period between the concept selection and the beginning of the infrastructure operation is five years, meaning that the analysis period includes about 35 years of pipeline operations.

In the discussion that follows, we refer primarily to the analysis of the two alternative logistical concepts of gas transportation: pipeline and LNG, which is in line with the ongoing discussion regarding the major infrastructure development in the Barents Sea (see e.g. Gassco, 2014). However, the analysis of alternatives may also be related to the choice of whether to process gas offshore or transport it onshore for processing, the choice of the landing point onshore or the choice of whether to connect the new infrastructure to the domestic network or to the network of another country (e.g. the UK).

The purpose of a CBA is to measure the effects of a project on the social welfare of a country. A change in social welfare can be measured as a change in the total social surplus. Formally, under the competitive markets assumption, the change in the social surplus can be expressed as follows:  $\Delta SS = \Delta CS + \Delta PS + \Delta GS$ , where  $\Delta SS$  is the change in the social surplus;  $\Delta CS$  is the change in consumer surplus;  $\Delta PS$  is the change in producer surplus; and  $\Delta GS$  is the change in governmental surplus.

For an export-oriented country like Norway (about 98% of the gas produced is exported), the effect on consumer surplus is negligible. Unlike most CBA applications, the main element of a CBA in the Norwegian gas sector is the change in producer surplus. This change can be measured as the effect of the project on the following four groups of stakeholders: (1) shippers in the new infrastructure; (2) investors in the new infrastructure; (3) shippers in the existing infrastructure and (4) owners of the existing infrastructure. In many cases, one company can be represented in each of the four groups. For example, in an LNG project, shippers and investors comprise the same companies; in a pipeline project, most of the potential shippers participate in the investments, at least in the initial stages (the participating interest in the pipeline infrastructure can be sold at later stages, or institutional investors can participate in the project from the beginning). Therefore, in order to structure the analysis, this provisional classification of stakeholders can be regarded as a classification of the different roles of companies in a project.

The change in governmental surplus is determined by government spending on a project and the income generated. On the NCS, there is neither direct public funding of infrastructure projects nor direct tariff income from the transport infrastructure for the government. However, the state indirectly participates in infrastructure investments via the major Norwegian gas producer, Statoil (67% state ownership) and the state-owned company Petoro. The task of Petoro is to manage the holdings of the Norwegian state in production licences and associated facilities on the NCS. Petoro acts as a licensee on behalf of the state and participates in infrastructure investments proportional to its shares in the corresponding gas fields. Through this participation interest, the state receives the tariff income from the infrastructure use. In the proposed CBA framework, these effects are captured in the evaluation of the change in producer surplus. Another major revenue source for the government is corporate tax on the petroleum activities on the NCS. In a CBA, cash flow is calculated before tax as corporate taxes represent a cash flow redistribution.

In a perfectly competitive market situation, the formula mentioned above would capture the total welfare change. However, there are externalities in gas transport infrastructure projects – direct effects on third parties – for example, environmental impacts, impacts on fisheries and shipping and other effects on primary markets. Third parties represent the fifth group of stakeholders in the proposed methodology. Infrastructure projects in the gas sector may also have effects on secondary markets: methanol production, electricity market, labour market and regional economic activity. In this paper, we refer to a welfare function whose scope is limited to the gas production and transportation sector and leave the effects on secondary markets out of the scope of this paper on the basis of the efficient markets assumption (Boardman et al., 2013).

### 2.3 Relevant impacts

As the scope of analysis is limited to gas transport infrastructure projects, the revenue from the sales of dry gas and natural gas liquids and the corresponding production costs are excluded from the analysis. However, if an LNG alternative is considered, the value of the destination flexibility provided by the possibility of shipping the gas to the highest value markets (a price premium) should be included as a benefit for shippers (for a methodology on real option valuations of LNG destination flexibility, see e.g. Rodríguez, 2008). The cost for shippers of using a new pipeline are represented by the tariffs paid for the use of this new infrastructure as well as for the transportation of gas in the existing infrastructure downstream. The LNG transportation chain does not imply any regulated tariffs; the costs for shippers are related to the liquefaction of gas and sea shipping.



Another important aspect of the evaluation of impacts on shippers in the new infrastructure relates to the technical aspects of the pipeline transportation. Gas moves along pipelines due to the pressure produced by compressors installed at the pipeline entries, for the upstream pipelines – at the offshore platforms. The capacity and technical characteristics of these compressors are determined by the technical characteristics of the pipeline. In fact, these compressors are part of the pipeline transportation chain. However, export compressors are considered part of the field infrastructure. The cost of these compressors and of the energy required for their operation are attributed to the cost of the field development and operation and are not considered within the evaluation of transport infrastructure projects. When a pipeline solution is compared to an LNG solution, which does not require compression, the export compressors and the energy for their operation become a natural part of the transport-related costs, in addition to the tariffs paid to the pipeline owners.

The impacts on new pipeline infrastructure investors are the investment costs and the expected income from the transportation tariffs. On the NCS, the transportation tariff consists of a capital element and an operating element.<sup>5</sup> The capital element paid by the shippers is transferred to the infrastructure owners while the operating element covers the costs of operating and maintaining the infrastructure. In the case of an LNG alternative, the cost for investors is the investment in LNG tankers and a liquefaction facility.

The inflow of gas from a new pipeline infrastructure affects the shippers and owners of the existing network. A higher volume of gas in the pipeline system may reduce the unit cost of transportation, in turn reducing the operating element of the tariff and rendering cost savings to all shippers. The owners of the existing infrastructure may experience revenue increases through the capital element of the tariff paid for the transportation of the volumes of gas from the new infrastructure.

The remainder of the Norwegian society is affected by the externalities of gas infrastructure projects. Many of these effects, for example, the distortion of fisheries and shipping, occur only during the construction of facilities and are often of a limited scale. The environmental impacts (emissions to air and sea and landscape impacts) occur both during the construction stage and normal operations. The construction and preparation of the facilities for operation generate emissions to air from installation equipment and vessels. Emissions of cooling and ballast waters to the sea occur during the installation and spillage of chemicals during the cleaning and testing of pipelines. The impacts on the landscape are related to the construction of processing plants onshore. Impacts on sea flora and fauna can be caused by the damage of corals by anchors as well as the disturbance of fish and sea birds during construction. Disturbances by noise and light on nearby dwellings can be caused during operations. Most of these impacts are of a very limited nature, and many of them are not directly quantifiable. However, in cases in which these effects are not negligible, they should be internalized in the analysis according to the social value (e.g. Aanesen et al. (2015) provide estimates of the willingness-to-pay for preserving cold-water corals in Norway).

During normal operations, the main environmental impacts from the transport infrastructure are emissions to air caused by energy production. Export compression relating to pipeline transportation and gas liquefaction in an LNG chain requires large amounts of energy, which in many cases is generated by gas turbines, causing significant CO<sub>2</sub> and NO<sub>x</sub> emissions. Due to the technological specificity of LNG facilities, there may also be considerable methane leakage. Alternative pipeline solutions may also have significantly different environmental footprints, depending on the possibility of connecting the offshore facilities to the main electricity grid onshore. Shaton et al. (2016) estimate emissions to air from the alternative

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<sup>5</sup> Regulations relating to stipulation of tariffs, etc. for specific facilities, 20 December 2002, No. 1724

transportation chains on the NCS. Besides displaying a variety of the footprints of different pipeline chains and the significant superiority of the pipeline transportation over the LNG, the study also shows that transportation-related emissions constitute a considerable component of the total emissions by the gas sector. It should be noted that the costs of CO<sub>2</sub> and NO<sub>x</sub> emissions are partially internalized in the existing appraisal practice through the corresponding taxes included in the cost calculations. However, the existing tax system does not necessarily reflect the social value of these emissions. In such cases, the eventual difference between the social values and the taxes paid should be accounted for in the economic analysis of infrastructure projects.

The priced impacts need to be discounted by the social rate in order to calculate the net economic benefits of a project. A discussion on the derivation of the appropriate social discount rate is left out of the scope of this paper. For further analysis, we use the a social discount rate, recommended for the socio-economic analysis of an ordinary public measure in Norway by Hagen et al. (2012).<sup>6</sup>

## 2.4 Uncertainty

One approach to treating uncertainty is to add a risk premium to the discount rate. An alternative is to use certainty equivalents in the analysis and discount them using a risk-free discount rate (Boardman et al., 2013). The first approach is used in the practice of the impact assessment in the sector whereby a risk premium of two or three percent is used. This approach may be considered as a simplification. A more elaborate approach would be to consider project-specific sources of uncertainty separately and apply suitable techniques to deal with them while applying a risk-free rate for cash flow discounting. Uncertainty over investment costs, for example, can be treated by means of expected values. However, this approach is not appropriate for the uncertainty regarding the utilisation rate of the planned facilities.

The expected production rate is a critical factor in decision-making regarding the concept selection of an infrastructure solution, especially the capacity of facilities. It is determined mainly by two uncertain parameters: the gas prices and the rate of exploration success. In planning an infrastructure, petroleum companies focus on particular fields, with a reasonably well defined resource volume. Therefore, the dynamics of gas prices and potential contractual agreements determine their need for transport capacity. The independent system operator involved in infrastructure planning takes a long-term perspective and accounts for possible discoveries and future tie-ins in the system. For the system operator, exploration success is the focal uncertainty factor.

We consider a case in which the capacity of a pipeline which connects a new area with the existing network is being decided. The tariff system on the NCS is arranged by zones. A new project of this type will comprise a new zone, with a tariff set up by the regulator independently from the remainder of the network. The existing tariff system is based on the rate-of-return regulation, which allows the recovery of the investment cost within the license period. Therefore, the tariff can be approximated as a long-run average cost (LRAC) of transportation. The Norwegian gas transport system is a natural monopoly facing increasing returns to capacity, which implies that the LRAC curve is downward-sloping (Church and Ware, 2000).

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<sup>6</sup> The NOU 2012:16 Green Paper recommends a real risk-adjusted discount rate of four percent for effects in the first 40 years, three percent from 40 to 75 years and two percent for subsequent years.

The demand for the transportation service ( $D$ ) is driven by two parameters, the demand for gas and the production rate, which depends on the exploration success. We assume that all the Norwegian gas produced will be sold; thus, the demand for transportation is considered from the perspective of proven gas resources and possible discoveries. An infrastructure project is initiated by gas companies in order to establish means for evacuating the gas from their gas fields (a committed volume). In the planning horizon of gas companies, their demand for the transportation service is fixed. In Figure 2.1, the short-term demand for the transportation service,  $D_0$ , is represented by a vertical line. The gas companies propose a pipeline solution (a '0-alternative') with a capacity of  $C_0$ , corresponding to the committed volume of  $V_0$ . This capacity implies an  $LRAC_0$  curve. The tariff ( $T$ ) would be set at the level  $t_0$ .

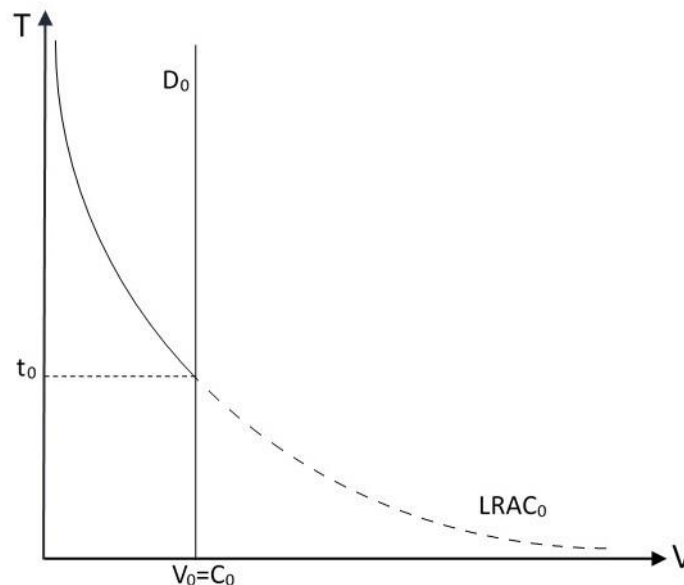


Figure 2.1 The short-run demand for transportation services

The system operator considers the new infrastructure from the long-term perspective and takes into account possible new discoveries in the area above the committed volumes. Figure 2.2 depicts a situation in which the system operator suggests a pipeline solution ('alternative-1') with capacity  $C_1$ , on the basis of its medium resource scenario. A solution with a higher capacity requires higher investment costs and implies the long-run average cost curve  $LRAC_1$ . The long-run demand curve  $D_1$  is downward sloping: the transportation tariff will affect decisions to develop new fields in the area. However, the long-term demand is rather inelastic down to a certain tariff level; thus, for major and mid-sized developments, the tariff level may not be a decisive factor. The development of marginal fields is more sensitive to transportation costs. Below a certain tariff level, the cost threshold for the development of marginal fields is surpassed, and demand becomes more elastic.

In a short-term perspective, the cost function  $LRAC_1$  suggests a higher tariff,  $t_1$ , due to the higher initial investment. However, if the medium-resource scenario occurs, the tariff is established at a lower level,  $t_1^*$ , and the volume transported increases to  $V_1$ .

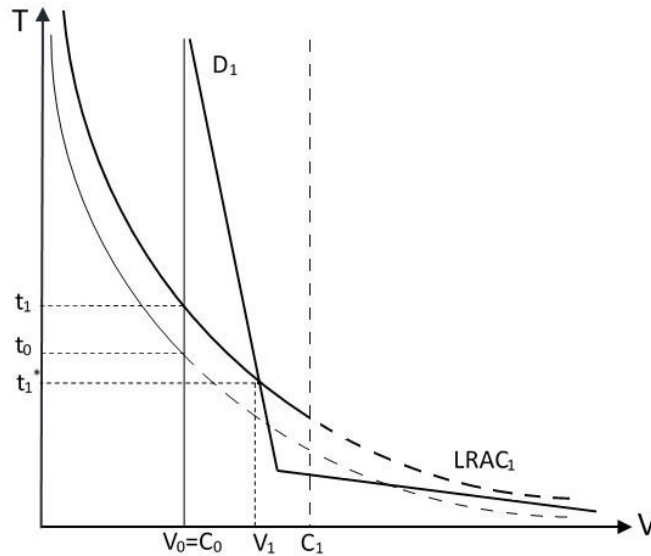


Figure 2.2 The long-run demand, medium resource scenario

The system operator also considers possibilities of low and high resource scenarios. If the high resource scenario occurs, the capacity of 'alternative-1' is not sufficient in the long run, and a new transport solution may be required, or resource development may be postponed until there is available capacity in the established solution – both outcomes mean some welfare loss. Therefore, the operator considers the solution of capacity  $C_2$  ('alternative-2'), which implies the cost curve  $LRAC_2$  (Figure 2.3). If there are significant discoveries in the area, the demand function shifts to the right, and its elastic component begins at a higher tariff (meaning that in addition to large discoveries, many smaller deposits have been discovered with a lower cost threshold than before). If the second alternative is selected, the new tariff  $t_2^*$  could be established at the first intersection of the demand function with the cost curve; the volume transported would then be  $V_2^*$ . However, the demand curve crosses the cost curve  $LTAC_2$  again after the kink. This means that the tariff  $t_3$  established at the intersection of the cost curve with the capacity limit would motivate the development of the marginal fields up to the transport capacity limit  $C_2$ .

The problem with 'alternative-2' is that if the medium resource scenario occurs, the tariff would be established at level  $t_2$ , implying the volume of transported gas  $V_2$ , which is lower than the corresponding volume  $V_1$  if 'alternative-1' is chosen. If there are no new significant discoveries in the area at all – a low resource scenario occurs, and the demand for the transportation service does not increase – the tariff should be even higher in order to recover the investment costs.

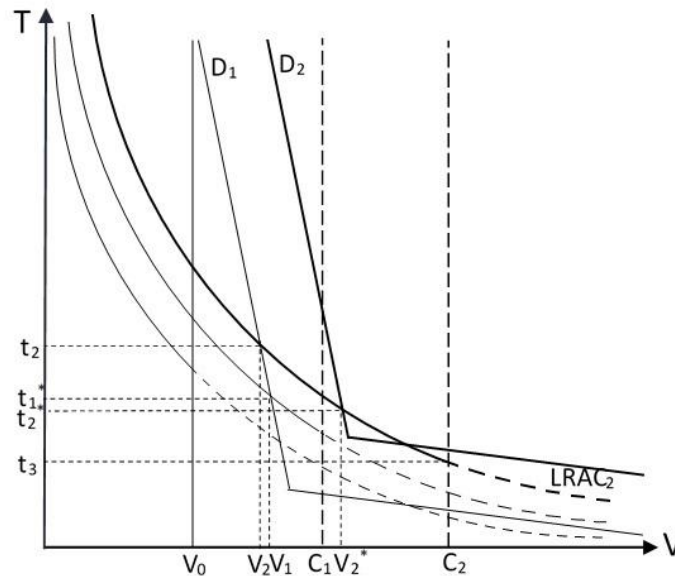


Figure 2.3 The long-run demand, high resource scenario

According to the standard CBA methodology, such uncertainty should be dealt with using the expected values or a scenario analysis. However, a solution with excess capacity may be regarded as a solution with additional flexibility, which cannot be captured in the standard NPV calculation. Pre-investments in additional capacity provide opportunities to expand production in the future and connect new fields if the market conditions are favourable. Such flexibility has significant socio-economic value in the long run, which should be weighted upon the tariff increase due to a higher investment cost. This approach calls for the use of real options in a CBA: the value of flexibility should be added to the benefits of a solution with excess capacity. Shaton (2015) suggests a methodology for real option valuations of the flexibility provided by excess capacity in gas transport infrastructure investments and shows that this value can influence decisions in favour of the pipeline alternative with upfront investments.

## 2.5 Structure of a CBA

Figure 2.4 summarizes the discussion so far and presents a general structure of a CBA for a case in which an LNG solution is compared with a pipeline solution with excess capacity with regard to future tie-ins (the LNG chain has no economies of scale in investments).

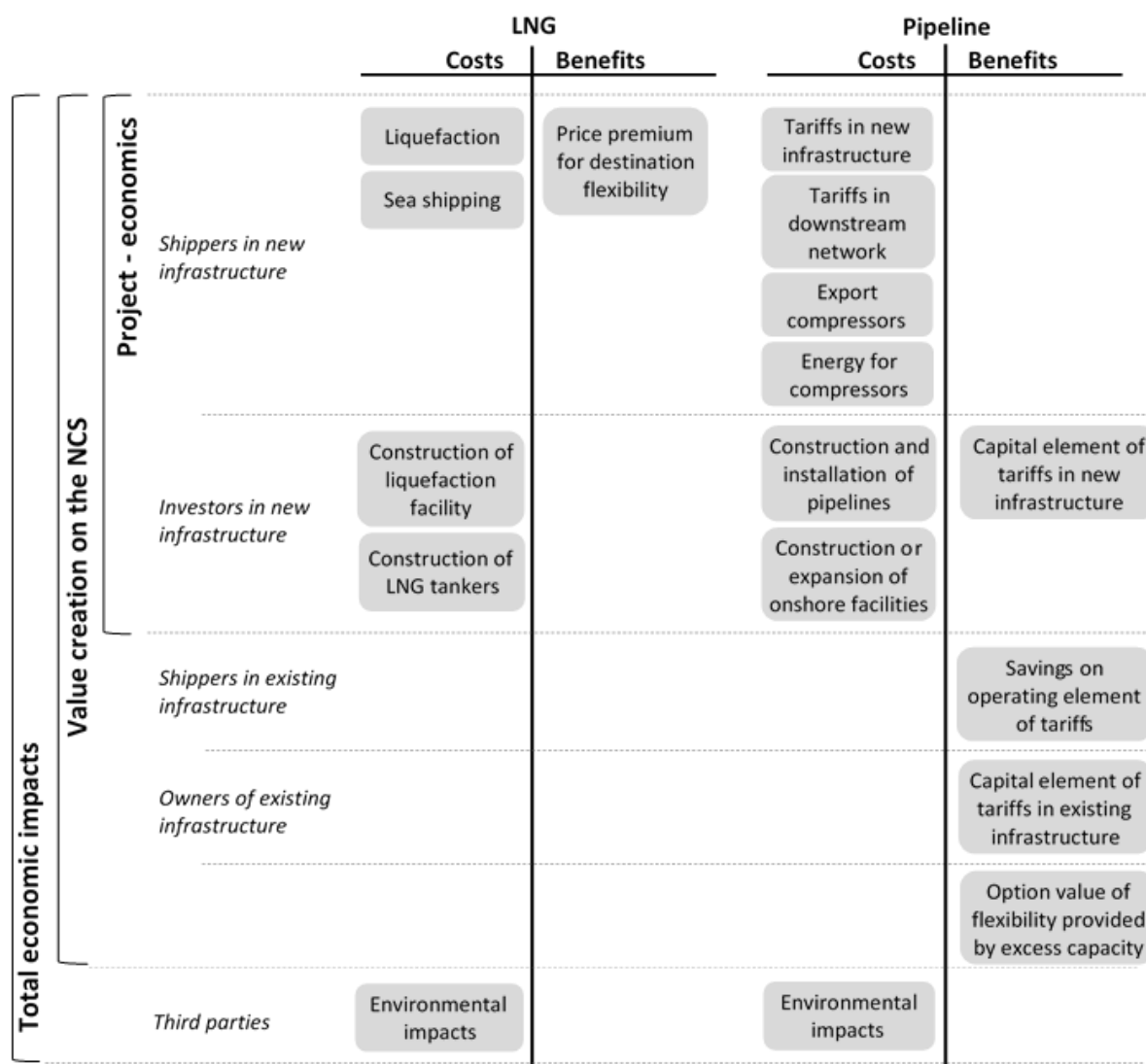


Figure 2.4 The structure of a CBA of an infrastructure project in the upstream gas sector

The CBA approach provides a framework for a comprehensive economic analysis of a gas transport infrastructure project, which includes the impacts on all three levels of the investment problem. At the project level, we consider the costs and benefits occurring to the shippers and investors in the new infrastructure. The NPV calculation at this level (though with a shorter analysis period and a higher discount rate) represents the view of the project by the petroleum companies involved.

The second level of analysis includes all impacts of an infrastructure project relating to value creation in the gas sector such as the tariff impacts on the shippers and owners of the existing network and the value of flexibility provided by excess pipeline capacity. In fact, the savings in operating costs in the existing network for the shippers and the tariff income for the owners (the benefits at the second level) are provided by the tariffs paid by the shippers in the new infrastructure for the use of the downstream network (the costs on the first level). It means that these two groups of effects will be nullified in the outcome of the analysis. However, the consideration of the impacts on the existing infrastructure is especially important when a pipeline solution is compared to an LNG solution, which has no impact on the rest of the network. The NPV calculation at this level represents the perspective of the system operator, which coordinates all infrastructure planning on the NCS.

The third level adds the environmental externalities to the picture and completes the economic analysis of a project.

Certainly, the results of such an analysis should be subject to a sensitivity analysis with respect to the main uncertainty parameters: investment costs, gas and carbon prices, LNG shipping costs, regularity of transportation and liquefaction facilities.

In the next section, we discuss a recent infrastructure project on the NCS, through the lenses of the analytical framework presented above, in order to determine what CBA can add to the existing appraisal practice.

## 3 Case study

### 3.1 Case description

The Polarled pipeline project (planned start in 2017, formerly called the Norwegian Gas Transport Infrastructure – NSGI) was triggered by the need for an export solution for the Aasta Hansteen field (operated by Statoil) in the Norwegian Sea (Figure 3.1). The following alternatives were initially considered: a direct 500 km rich gas pipeline to the onshore plant at Nyhamna for processing and further transport to the market via the export pipeline Langeled; a new onshore processing facility in geographical proximity to the field with two possible export solutions, either LNG or further connection to Nyhamna; a connection to the existing processing facility at Tjeldbergodden, which processes gas for domestic use, and a floating LNG solution. The LNG solution was rejected because it was technically impossible within the established timeframe as well as the high uncertainty over the cost of such a solution. The connection to Tjeldbergodden was rejected because the expected volume of gas from the fields in question exceeded domestic demand; an export solution would thus be needed. The alternative of a new processing plant onshore was ruled out because of much higher investment costs in comparison to the direct connection to Nyhamna (the estimated costs were 65 and 25 billion 2012-NOK for LNG and a further connection to Nyhamna, respectively, and 10 billion 2012-NOK for the direct pipeline to Nyhamna,  $\text{NOK}8.5 \approx \text{€}1$ ).

The solution with a direct pipeline to Nyhamna was also attractive because of available spare capacity at the Nyhamna plant and in the export pipeline system Langeled. This alternative made it possible to connect the Linnorm (operated by Norske Shell) and Zidane (operated by RWE Dea Norge)<sup>7</sup> fields and establish a tie-in to another rich gas pipeline, Åsgard Transport. The prospects of a combined solution and possibility for new discoveries in the area motivated the consideration of a pipeline of 28" to 40" and a capacity of 35 to 85  $\text{MSm}^3/\text{d}$ .

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<sup>7</sup> The development decisions for these two fields have been postponed, but the owners are participating in the pipeline project.



Figure 3.1 Map of the pipelines on the Norwegian shelf. The Polarled pipeline is denoted by the densely dotted line (Source: Norwegian Petroleum Directorate).

The system operator Gassco was responsible for the project up to the concept selection (a 36" rich gas pipeline with a capacity up to 70 MSm<sup>3</sup>/d from the Aasta Hansteen field to the processing plant at Nyhamna). At that point, the operatorship of the project for the construction phase was delivered to Statoil, which prepared the plan for installation and operation and the respective impact assessment of the pipeline project. The project required an expansion of the Nyhamna processing plant. Shell, the plant operator, was responsible for the plan and the impact assessment of the expansion.

### 3.2 Results

The appraisal of the Polarled project is represented by several publicly available documents. The two principal documents are the plans and impact assessments of the installation and operation of the Polarled pipeline and of the expansion of the Nyhamna processing plant (2012). Some information relating to the pipeline project is also presented in the plans and impact assessments of the development and operation of the gas fields Aasta Hansteen, Linnorm and Zidane. The impact assessment of the Polarled pipeline covers the impacts relating to the pipeline itself and does not include impacts from the compressors installed at the pipeline entries and those relating to the connection of the pipeline to the onshore plant.



The first set of impacts is included in the impact assessments of the corresponding fields while the other set is included in the impact assessment of the plant expansion. The system operator Gassco also performed its own evaluation of the project; however, the relevant reports are not publicly available. In the analysis that follows, we refer to the CBA structure provided in Section 2.5 and consider which parts can be recovered from the available documents while seeking to determine which parts are missing.

According to the proposed structure, the impacts on shippers in a pipeline are the tariffs and costs associated with gas compression. In the appraisal practice, the tariffs are included in the profitability assessments of the fields; the cost of compressors are considered as part of the field infrastructure costs; and the energy used for running the compressors is considered as part of the operating costs of the field. Thus, the impacts on shippers can be recovered from the information provided on the field developments, and we can conclude that in this way, these impacts are actually internalized in the appraisal practice. However, this will cover only part of the analysis period. The expected lifetime of Aasta Hansteen is nine years, Linnorm is 15 years, and Zidane is 10 years, meaning that the effects occurring after the initial fields have ceased operation are missing in the appraisal picture.

The impacts on the investors are the investment costs and tariff revenue. In the documents relating to the Polarled pipeline and plant expansion, only the cost side is evaluated; the revenue aspect is not covered. According to the petroleum regulation,<sup>8</sup> the capital element is stipulated such that it should bring a 'reasonable return on investments', which has been at the level of seven percent thus far. In the appraisal practice, a seven percent discount rate is used; therefore, the effect on the investors is nullified. In performing a CBA, we would use a social discount rate of four percent, recommended by Hagen et al. (2012). This means that investors will receive profits from the project during the license period (typically about 30 years), which is also missing in the appraisal picture. Due to the absence of the data on the tariff in the new infrastructure, we cannot estimate these effects.

The plans and impact assessments discussed above are project-specific and are not intended to cover a wider perspective; therefore, they do not consider the effects on the existing network. We attempt to estimate the impacts on the shippers and owners of the existing network on the basis of the publicly available data on the tariffs on the NCS.

The gas transported via the Polarled will be exported via the Langeled pipeline system after being processed at Nyhamna. This pipeline system is part of the tariff zone 'Area D'. This zone includes all dry gas pipelines that deliver sales gas to the receiving terminals in continental Europe and the UK. In 2012, the unit operating cost of transportation in Area D was 0.0203558 NOK/Sm<sup>3</sup>. The total volume of gas transported in Area D is about 100 billion Sm<sup>3</sup> annually, and an inflow of gas from Polarled may account for an additional 15 billion Sm<sup>3</sup> annually. According to our consultations with industry experts, this inflow will not change the total operating costs in Area D. This means that the unit operating cost will be reduced. An approximate calculation yields 265 million NOK in annual savings for other shippers. Discounting this number over the analysis period, the total saving for shippers in the existing network amounts to 4.22 billion 2012-NOK.

The shippers of the Polarled gas will also pay the capital element of the transportation tariff in Area D until 2028 when the license for this infrastructure expires. In 2012, the capital element for the UK and continental exits in Area D was 0.0679003 NOK/Sm<sup>3</sup>. A year later, it was reduced by 90%. This was a transition from long-run average cost-based tariffs to short-run average cost-based tariffs because the rate of return on this infrastructure had already

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<sup>8</sup> Regulations to the Act relating to petroleum activities, 27 June 1997, No. 65.

achieved seven percent, and the investment cost had been recouped. It is unclear which of the two tariffs would have been used for such calculations back in 2012 when the project was evaluated. Discounting over the license period, there is the additional revenue of 12.22 billion for the 2012 tariffs and 1.22 billion for the 2013 tariffs for the existing infrastructure owners.

Supposedly, these two sets of impacts are considered within the system operator's evaluation of the project. We can conclude that these impacts are also internalized in the decision-making although they are not explicitly estimated.

The third impact considered at this level of analysis is the value of flexibility provided by excess pipeline capacity. In practice, this value is also not explicitly estimated, but the choice of the solution for this project (a pipeline with a capacity of 70 MSm<sup>3</sup>/day while the committed volumes are not more than 44 MSm<sup>3</sup>/day) indicates that, implicitly, this value is also internalized in the appraisal practice.

The participation of the system operator in investment planning ensures that the economic impacts of a project on the value creation in the sector are internalized in the decision-making. However, the scope of the system operator's responsibilities does not include the external effects of infrastructure projects. These effects are only evaluated within the impact assessments performed by gas companies when the final solution is selected.

In the impact assessment of the construction and operation of the Polarled pipeline, the environmental impacts were characterised as insignificant. The emissions of CO<sub>2</sub> and NO<sub>x</sub> during the construction and preparation of the pipeline were estimated at 44,290 and 976 tonnes, respectively. The emissions during the normal operation were limited to the emissions from vessels associated with inspections, supplement rock dumping and eventual reparations of the pipeline, and were characterized as negligible. In order to estimate the emissions relating to the compression of gas for transportation in the Polarled pipeline, we used the data in the impact assessments of the field developments.

The impact assessment for Aasta Hansteen provides the total average yearly emissions: 250,000 tonnes of CO<sub>2</sub> and 210 tonnes of NO<sub>x</sub>. However, the data on the allocation of these emissions between the emission sources (turbines, flares, engines, other emissions) is not provided. The reported emissions from the fields operating on the NCS indicate that turbines account for about 90% of total emissions (e.g. 90.2% for Norne; 88.78 for Snorre; and 90.18 for Kristin in 2014). The two gas turbines installed at the Aasta Hansteen platform will generate a total of 43–54 MW of electricity to supply energy to all processes on the platform; out of this total, 31–43 MW will be required for export compression. Based on this information, we estimate the transportation-related emissions at Aasta Hansteen as 72% of the total (Table 3.1).

The impact assessment of the Linnorm field development provides separate emissions-related information on compression. The export compressor will be installed at the Draugen platform, which, according to the plan, will receive, process and compress the Linnorm gas before sending it to the Polarled pipeline. The compressor will generate about 90,000 tonnes of CO<sub>2</sub> annually, which is 82% of the total emissions related to this field, and about 50 tonnes of NO<sub>x</sub> a year.

According to the Zidane impact assessment, the energy for the field will be produced at the Heidrun platform, which will process the gas from Zidane. The average yearly emissions at Heidrun in relation to the Zidane operations will be 50,000 tonnes of CO<sub>2</sub> and 25 tonnes of NO<sub>x</sub>. As the data on the distribution of these emissions between the processes is not available, we used the 80% estimate for the share of the transportation-related emissions, in line with the data for Linnorm, based on the similarity of the development concepts.

*Table 3.1 Estimates of the total CO<sub>2</sub> and NO<sub>x</sub> emissions related to transportation*

Field	Max production rate, MSm <sup>3</sup> /day	Estimated CO <sub>2</sub> emissions from compression, tonne per year	Estimated NO <sub>x</sub> emissions, tonne per year
Aasta Hasteen	22	180,000	150
Linnorm	13	90,000	50
Zidane	8	40,000	20
Total	44	310,000	220

Table 3.1 shows that the export compression of gas from the three fields, which were slated for connection to the Polarled pipeline, would cause annual emissions of 310,000 tonnes of CO<sub>2</sub> and 220 tonnes of NO<sub>x</sub>. The production volumes from these three fields can fill up to 63% of the pipeline capacity. Active exploration activity in the areas close to the Polarled pipeline allows the conservative assumption that the utilization rate will increase up to 80% after the first ten years of the pipeline's operation (the current utilization of the closest rich gas pipeline – Åsgard Transport – is nearly 100%). Assuming a linear relationship between the gas volume needed to be compressed and the emissions by gas turbines running the compressors, at 80% utilization of the pipeline, the annual CO<sub>2</sub> and NO<sub>x</sub> emissions will be 394,000 and 280 tonnes, respectively. During the 40 years of the analysis period, which includes 35 years of pipeline operation under the above-described utilization scenario, the total emissions relating to the Polarled pipeline (including construction and operation) are 12,985,563 tonnes of CO<sub>2</sub> and 10,060 tonnes of NO<sub>x</sub>.<sup>9</sup>

In order to estimate the cost of the environmental externalities from gas transportation in the Polarled pipeline, we used the calculation prices used in Norway for public roads infrastructure projects (Table 3.2) and adjusted them based on environmental taxes paid by companies.

*Table 3.2 Norwegian calculation prices of CO<sub>2</sub> and NO<sub>x</sub> emissions in 2012*

	2009-NOK per tonne of CO <sub>2</sub>	2009-NOK per kg of NO <sub>x</sub>
2015	210	50
2020	320	50
2030 and further	800	50

Source: Institute of Transport Economics (Magnussen et al., 2010)

According to Prop. 1 LS (2011-2012), the tax for the continental shelf of natural gas was 209 NOK per tonne of CO<sub>2</sub> and 16.69 NOK per kg of NO<sub>x</sub> in 2012. Due to the fact that a substantial part of CO<sub>2</sub> emissions in the sector was covered by the Allowance Trading scheme, the price paid by companies for a tonne of emitted CO<sub>2</sub> was about 250 NOK. With all prices adjusted to the CPI, and using the social discount rate of four percent, we obtained the cost of the environmental externality of 3.14 billion 2012-NOK (2.98 billion for CO<sub>2</sub> and 0.16 billion for NO<sub>x</sub>).

<sup>9</sup> During the 50 years of the expected lifetime of the pipeline: 18,846,032 tonnes of CO<sub>2</sub> and 13,375 tonnes of NO<sub>x</sub>.

### 3.3 Discussion

The case study of the Polarled project shows that the existing appraisal system internalizes most of the economic impacts of infrastructure projects. However, the assessment of these impacts is scattered between the parties participating in a project and are often evaluated indirectly. The proposed CBA method provides a framework for a systematic and comprehensive analysis. Summarizing the findings of the case study, we can define the following potential contributions of CBA to the existing appraisal practice.

The proposed approach focuses on the transportation solution, separating the transport infrastructure project from field developments. The analysis includes all components of the gas value chain relating to the transportation of gas. In particular, we consider export compression, which in practice is considered part of the field infrastructure, as a part of the pipeline transportation chain; and consider liquefaction as part of the LNG transportation chain.

The effects on the shippers and owners of the new infrastructure are captured in the existing practice in the evaluation of the fields, which are initially associated with an infrastructure project. However, the lifespan of the initial fields is typically shorter than that of the transport infrastructure. The CBA approach also internalizes the impacts on shippers and owners which occur after the initial fields cease production. Besides considering the impacts within a longer analysis period, we discount the cash flows with a social discount rate. This reveals the effects that are nullified under the commercial discounting.

The impacts on the shippers and owners of the rest of the network are implicitly internalized in the decision-making due to the participation of the system operator in investment planning. However, these impacts are not explicitly estimated. The case study indicates that their scale is considerable; for example, the operating cost savings for shippers in the existing network were 2012-NOK 4.22 billion while the expected investment cost was about 10 billion. The CBA provides a framework for a systematic appraisal of these impacts within the project analysis.

The proposed structure also internalizes values of flexibility in the infrastructure investments. These are the destination flexibility of the LNG solution, which allows the shipping of gas to the highest value markets, and the strategic flexibility provided by excess pipeline capacity, which provides possibilities for future tie-ins.

An important contribution of the proposed method is the analysis of external effects. The costs of environmental impacts associated with gas transportation are partially internalized in the existing practice via the environmental taxes included in the operating cost calculations. In the CBA, these impacts are assessed according to their social value. Furthermore, we estimate the environmental externalities over the whole analysis period, beyond the lifetime of the initial gas fields. The estimates provided in the case study show that emissions to air associated with pipeline transportation are significant when the entire transportation chain is taken into consideration; and the cost of this environmental externality is an important aspect of a comprehensive economic analysis of a project.

## 4 Conclusions and policy implications

Investments in upstream gas transport infrastructure are undertaken by commercial oil and gas companies that make final investment decisions and take investment risk. However, an infrastructure project may have long-term effects on the existing gas transport network and overall value creation in the sector. Moreover, infrastructure development may have

externalities. The regulatory framework in the Norwegian gas sector is organised such that commercial interests are balanced with socio-economic considerations. In gas transport infrastructure development, this is achieved through the participation of the system operator in project planning and concept choice as well as project assessment by relevant before statutory approval. The infrastructure development decisions taken on the NCS so far reflect the fact that the effects on value creation in the gas sector and the effects on third parties are, to some extent, implicitly taken into account in decision-making. However, some important socio-economic impacts can be missing or may not be explicitly evaluated in the existing appraisal practice. The proposed CBA method offers a framework for a comprehensive economic analysis of infrastructure projects in the upstream gas sector. The introduction of CBA does not require structural changes of the established planning and appraisal procedures; it can be regarded as a missing link in the existing practice and can play a coordinating role in planning and appraisal.

This paper discusses the application of CBA in the Norwegian upstream gas transport sector, however, it can be used in the gas sectors of other gas producing countries. The proposed methodology can be adjusted in correspondence with the specificity of the institutional environment or peculiar properties of a project.

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**Paper 2**

**Value of flexibility in gas pipeline investments**

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# Value of flexibility in gas pipeline investments

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## Abstract

Investments in upstream gas pipelines are characterised by significant economies of scale: low additional costs are required to establish capacity in excess of the committed volumes. The excess capacity provides flexibility for cost-efficient expansions of the transportation system in the event of future discoveries. Therefore, investments in excess pipeline capacity may have a significant effect on the value creation in the gas sector in the long run. Flexibility to expand the transportation network can be regarded as an option to be exercised if there are new discoveries and market conditions are favourable. The objective of this paper is to consider how real options thinking can be applied to estimate the monetary value of the flexibility provided by investments in excess capacity in upstream gas pipelines. The proposed approach is based on binomial lattices, allowing for the inclusion of both market and project-specific risks in the evaluation. The provided example demonstrates how this value can be used by a public decision-maker in the evaluation of infrastructure projects in the Norwegian gas transport sector.

**Keywords:** *Gas pipelines investments; Excess capacity; Value of flexibility; Real options*

# 1 Introduction

Critical elements of the efficient functioning of natural gas markets is access to gas transport infrastructures and the cost of using them. This relates both to the upstream, or producer, level and to the downstream, or consumer, level. However, the goals and decision criteria for gas transport infrastructure development differ between these two levels. Thus, major infrastructure development projects in the consumer-oriented European Union (EU) gas sector are associated with such policy objectives as market integration, security of supply, competition and sustainability, e.g. Regulation (EU) No 347/2013, and include the development of interconnectors between the national gas networks, liquefied natural gas (LNG) terminals and gas storage facilities. Infrastructure development decisions in the upstream gas sector have a different nature. First, such decisions largely depend on economics and technical characteristics of the field development projects that trigger the development of the transport infrastructure. Another important decision factor is the effects that the new infrastructure development will have on gas production and transportation in the adjacent areas.

A relevant example of an infrastructure project in the Norwegian gas sector is the ongoing discussion of a transport solution in the Barents Sea. Exploration interests of petroleum companies have moved further north of the Norwegian Sea and the Barents Sea. According to estimates provided by the Norwegian Petroleum Directorate (NPD), about 43% of all undiscovered petroleum resources on the Norwegian continental shelf (NCS) are attributed to the Barents Sea (NPD, 2014). The only gas transport infrastructure currently available in the region is the LNG facility at Melkøya, which processes the gas from Snøhvit, the only gas field operating in that region. The operator of the field considers the expansion of the production and, accordingly, the expansion of the LNG facility. The main advantage of this solution is the market flexibility: a producer is not locked into the European market; therefore, the gas can be shipped by vessels to the highest-value markets, presenting the potential for higher profits from the Snøhvit field.

However, there is also an alternative solution – a pipeline, connecting the Barents Sea with the existing transport network. This solution requires a higher initial investment and lacks destination flexibility, but implies considerably lower operating costs than the LNG. Another benefit of the pipeline solution is the utilization of the transport capacity in the existing pipeline network, which may become underutilized in the near future. Maintenance costs for these transport facilities will be shared between larger volumes of transported gas, reducing the total unit costs. The most important advantage of the pipeline solution is significant economies of scale in investments, which enables over-dimensioning.<sup>1</sup> With regard to future discoveries and corresponding tie-ins, the additional costs to establish a capacity above the committed volumes are low. Spare pipeline capacity in the transport system provides incentives for exploration in the region and reduces the cost threshold of developing gas deposits along the pipeline.

Two perspectives of evaluating upstream gas transport infrastructure projects can be distinguished. The first perspective represents the interests of a commercial petroleum company, which is willing to establish a transport solution for certain fields and considers the

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<sup>1</sup> For example, scaling rule used by the transport system operator is  $\text{cost1}/\text{cost2} = (\text{capacity1}/\text{capacity2})^{2/3}$ . Used downwards to 50% of original capacity and upwards to 200% of original capacity (Gassco, 2014).

infrastructure investments only one part of the field development. This perspective emphasises cost minimisation over the operation period of the fields in question. The second perspective evaluates the solution from the point of view of a public decision-maker, which aims to maximise value creation on the NCS in the long run and evaluates transport infrastructure projects beyond the lifetime of the fields that triggered the infrastructure development. In the Barents Sea infrastructure project, the first perspective emphasises market flexibility of LNG solutions and the related benefits, while the second perspective emphasises the benefits created by the economies of scale in investments of pipeline solutions and the opportunities provided by these.

According to a study conducted by the operator of the gas infrastructure network on the NCS (Gassco, 2014), existing fields and discoveries are not sufficient to justify an investment in a new pipeline infrastructure from the Barents Sea. While the pre-tax net present value (NPV, at 7% real discount rate) is similar for a new 32" pipeline and the LNG solution, the expansion of the LNG train is better when measured by the real internal rate of return (IRR) on investments. When the potential outcome of near-term (three years) exploration activities in the Barents Sea are taken into consideration, a 42" pipeline gives a higher NPV in four out of five exploration scenarios, and a marginally lower NPV in one scenario. An analysis of the long-term resource scenarios (40 years) also proves robustness of the pipeline solution with excess capacity.

From the NCS perspective, the excess pipeline capacity has a certain value, because it creates the potential to connect new fields at a low cost if there are new discoveries in the future. From the project-economic perspective, investments in the excess pipeline capacity represent capital tied up in unprofitable long-term investments, because of the high required rate of return in the petroleum industry. Therefore, the costs of excess capacity need to be justified analytically. However, the evaluation approach currently used does not directly quantify the benefits of the flexibility provided by the excess pipeline capacity (see, e.g., Gassco, 2012, 2014), although such a value might be an important part of the project evaluation from the perspective of the value creation in the gas sector in general.

Using real options analysis, this paper aims to suggest an approach to attach a monetary value to the strategic flexibility provided by excess pipeline capacity in the project evaluation by the system operator. Real options analysis provides a means to estimate the monetary value of flexibility in investments, which is the ability to alter the course of the project so that expected returns are maximised or expected losses are minimised (Brandão et al., 2005). Copeland and Antikarov (2001) define a real option as the right, but not the obligation, to take an action, e.g. deferring, expanding, contracting or abandoning, at a predetermined cost, called the exercise price, for a predetermined period of time – the lifetime of the option. Examples of project flexibilities include deferring investment until new information arrives, expanding operations if market conditions are favourable, abandoning a project, suspending operations temporarily, and switching inputs or outputs. This paper focuses on the options to expand gas production, which are provided by pre-investments in excess pipeline capacity.

The paper is organised as follows. A review of the relevant literature is presented in Section 2. Section 3 describes the approach chosen for a real options valuation in gas transport infrastructure investments. The application of this approach to the valuation of the flexibility provided by excess pipeline capacity is demonstrated in Section 4. The implications of such valuations on the investment appraisal and decision system in the Norwegian gas transport sector is discussed in Section 5. Section 6 concludes.

## 2 Literature Review

Petroleum investments are among the earliest applications of real options valuations. A license obtained by a petroleum firm for petroleum reserve exploration and operation can be considered an option to invest in the development of oil fields if market conditions are favourable. Examples of real options valuations of investments in petroleum reserves can be found in the classical books by Dixit and Pindyck (1994) and Trigeorgis (1996), as well as in a number of research articles. For example, Smith and McCardle (1999) consider applying the real options approach to oil and gas investment valuations, and discuss the benefits of real options analysis over the traditional decision analysis techniques. Lund (2000) considers the value of flexibility in offshore oil field developments on the coast of Norway, using stochastic dynamic programming to model market risk and reservoir uncertainty. Miltersen (2000) allows for a stochastic interest rate and convenience yields in real options valuation of petroleum deposit investment. Chorn and Shokhor (2006) combine Bellman's equation with a real options valuation algorithm to represent sequential investment decisions in petroleum field development. Johnson et al. (2006) examine the application of system dynamics to real options analysis in the oil and gas industry. Enders et al. (2010) apply stochastic dynamic programming to analyse the interaction between two types of real options arising in natural gas production: the option to scale the production level and the option to scale the extraction rate by pausing production.

The body of real options literature dealing with natural gas production is well developed. However, the focus on investments in transport infrastructures is limited. A common approach to deal with upstream gas transport infrastructure investments, both in the research and practice, is to apply optimisation techniques, where existing infrastructures and potential projects are included in the model, and the optimal design is defined with the focus on the properties of the network (see, e.g., Rømo et al., 2009; Hellemo et al., 2012). When the optimal design of a transport infrastructure is defined, the investment analysis focuses on the activities on its 'nodes': gas production and consumption, and treating the costs of the transport infrastructure development as part of the total costs of a project.

The downstream part of the gas value chain has started to attract the interest of real options research relatively recently. To name a few examples, Abadie and Chamorro (2009) present a valuation of investment options in a natural gas combined-cycle power plant and an LNG facility using the least squares Monte Carlo approach to model the fluctuation of gas prices. Following the same line of considering the power plant's output rate according to fluctuations in the prices of power and natural gas, Arvesen et al. (2013) estimate the additional value created by using the pipeline linepack for short-term storage. The authors explore how given the capacity of a pipeline, the inlet and output pressure in the pipeline can be adjusted, so that it is possible to inject gas at one rate and withdraw at a different rate. Their paper values one of the flexibilities of the gas transportation system from the point of view of a large industrial gas consumer, which may also be relevant for gas producers.

The main contribution of this study is the attempt to expand the scope of real options applications to the investment valuations of the upstream gas pipelines from the point of view of a public decision-maker.

## 3 Methodology

### 3.1 Real Options Valuation Approaches

Since the term 'real options' was introduced by Myers in 1977, real options analysis has attracted the attention of researchers and practitioners, and various approaches of real options valuations have been proposed (for a critical review, see, e.g., Borison, 2005). The so-called 'classic approach' (see, e.g., Amram and Kulatilaka, 1999) is based on the theory of financial option pricing introduced by Black and Scholes (1973). This theory presumes that markets are complete, and all risks are liquidly traded on the financial market and can be hedged by constructing a portfolio of financial instruments that provides the exact same payoff as the project itself in any state and at any point in time. This assumption rarely holds for real-world projects, since there are many non-tradable, or private, risks, which cannot be hedged away. In response, researchers (see, e.g., Dixit and Pindyck, 1994) have suggested using a finance-based real options approach to value projects where market risks dominate, and to apply decision analysis techniques (as decision trees) to projects with primarily private risks. However, some approaches allow for valuing projects where both types of risks are present to a significant extent. Smith and Nau (1995) proposed an integrated approach where both market and private risks are identified explicitly. According to this approach, market risks can be modelled using traditional financial option pricing techniques (the replicating portfolio approach), while private risks are modelled through subjective beliefs and preferences of stakeholders expressed as utility functions. Another approach to deal with incomplete markets in real options valuations has been proposed by Copeland and Antikarov (2001). This approach does not explicitly rely on the existence of a traded replicating portfolio that can serve as a basis for valuation of the project market value. Instead, it is assumed that the present value of the project without options (evaluated using a traditional discounted cash flow technique) is the best unbiased estimator of the market value of the project (the market asset disclaimer [MAD] assumption). The market value of the project is then assumed to vary over time according to a random walk stochastic process (geometric Brownian motion [GBM]), and the options can be valued using traditional option pricing methods. The assumption that the project value follows the GBM is based on Samuelson's (1965) proof that properly anticipated prices fluctuate randomly, meaning that multiple uncertainties affecting a project's cash flow, which can follow different stochastic processes, can be reduced to a single uncertainty that follows a GBM.

Numerous sources of uncertainty affect the volatility of project returns in the gas transport sector. The two main factors are the rate of exploration success and the dynamics of gas prices. Certainly, these are not the sole factors; there is also uncertainty over the investment costs, which may change significantly during the planning and construction period. The long-term valuations may also be affected by the development of new technologies that influence investment and operating costs. The dynamics of gas prices and investment costs are market uncertainties, while the rate of exploration success and technological developments are project-specific, or private, uncertainties. The approach to real options valuations in gas transport projects needs to be able to incorporate both types of uncertainties. Therefore, the relevant methodologies are the integrated approach of Smith and Nau (1995) and the approach proposed by Copeland and Antikarov (2001), henceforth, the CA approach. The latter approach is adopted for the purpose of this paper, as it can be relatively easily applied in practice.

There are two main ways of option pricing: a continuous model developed by Black and Scholes (1973) and a discrete approach of the binomial model by Cox et al. (1979). The CA approach relies on the binomial model, whereby the price of the underlying asset follows a multiplicative binomial process: the price can either move up by a fixed value  $u$  or down by a fixed value  $d$ . If the value of the project follows the GBM, this value at any point in time has a

lognormal distribution. By equating the first and second moments of a binomial and lognormal distribution, we derive that  $u = e^{\sigma\sqrt{t}}$  ( $t$  is the length of the binomial period,  $\sigma$  is volatility), under the assumption that  $u = 1/d$ . This procedure ensures that the discrete distribution approximates the continuous distribution in the limit. Applying this technique, we get a recombining (event) tree representing the development of the asset value  $S_{ij}$  ( $i$  is the index for time,  $j$  is the index for state at time  $i$ ).

In order to derive the value of the American call option, a decision tree is built. The tree is solved recursively. At the expiration date, the option value equals:

$$C_{ij} = \max(S_{ij} - E, 0) \quad (1)$$

where  $E$  is the exercise price of the option. Before the expiration date, the values on the nodes of the decision tree are defined using the risk-neutral probability approach (maximum between the value of the exercised option and the 'alive' option):

$$C_{ij} = \max\left(S_{ij} - E, \frac{(pC_{i+1,j} + (1-p)C_{i+1,j+1})}{1+r}\right) \quad (2)$$

where  $r$  is the risk-free rate and  $p$  is the risk-neutral probability of the project value in the next period. Solving the tree backwards, we obtain the value of the project at time 0.

The risk-neutral probability concept needs some explanation. The principle of risk-neutral valuation assumes that the expected future value of an option does not depend on the risk preferences of market players. This means that the expected return can be found by discounting at the risk-free rate. Hence, with continuously compounded growth, the expected value  $E(V)$  at the end of a time interval  $\Delta t$  satisfies the following equation:

$$\begin{aligned} E(V) &= V_0 e^{r\Delta t} = puV_0 + (1-p)dV_0 \Rightarrow \\ e^{r\Delta t} &= pu + (1-p)d \Rightarrow \\ \Rightarrow p &= \frac{e^{r\Delta t} - d}{u - d} \end{aligned} \quad (3)$$

### 3.2 Valuation of an Option to Expand

An option to expand can be valued as follows. The underlying risky asset is the value of project  $V$ , which follows a binomial stochastic process. The values of the up and down movements,  $u$  and  $d$ , are estimated based on the volatility of the project value. The expiration time is limited by the lifetime of the project. Additional investment needed to expand the project is the exercise price  $E$ . If the option to expand is exercised, the scale of the project is increased to a factor  $k$ . To find the values on the nodes of the decision tree, we start at the end node. If the increase of the project value due to expansion exceeds the cost of expansion ( $kV_{ij} - E > 0$ ), the option is exercised. At the expiration date  $t$ , the payoff is defined as:

$$C_{tj} = \max(V_{tj}, (1+k)V_{tj} - E) \quad (4)$$

Before the expiration, if the option is exercised, the payoff is  $(1+k)V_{tj} - E$ ; if the option is kept 'alive', the payoff is defined using the risk-neutral probability approach. The decision rule is:

$$C_{ij} = \max\left(\frac{(pC_{i+1,j} + (1-p)C_{i+1,j+1})}{1+r}, (1+k)V_{ij} - E\right) \quad (5)$$

The value of the flexibility is the difference between the value of the project with the option to expand ( $C_0$ ) and the value without the option ( $V_0$ ).

The described approach of the option to expand valuation can be adapted to upstream pipeline investments in the following way. The investment cost for excess pipeline capacity is the price that the investors pay to get the option to expand the system by tying-in new transport facilities and connecting new fields at a later point in time. The value of this option depends on the uncertainty over the project value. The project valuation includes all parts of the value chain, from the subsurface to the market, incorporating cost estimates from field developments, offshore and onshore processing facilities, and the transport of gas to the relevant market.

To approximate the stochastic process followed by the project value, three parameters are needed: the estimate of the current value of the project; the volatility of returns; and the risk-free rate. The risk-free rate over the life of the project is constant; the one determined by government bonds can be used. The initial project value  $V_0$  can be estimated as a traditional NPV, calculated based on the risk-free discount rate. The volatility of the project value  $\sigma$  is approximated by Monte Carlo simulation, which includes different price and resource scenarios. The upscaling potential  $k$  is limited by the available excess capacity. The exercise price of the option is the additional investment required to upgrade the pipeline with new compressors, and for the development of new fields that come on-stream if market conditions are favourable. The option to expand may be exercised at any time in the future, but is limited by the lifetime of the pipeline in question.

## 4 Example of Option Valuation

In order to demonstrate how the described technique can be applied to evaluate the value of flexibility provided by excess capacity, a simulated example is considered. The example has the problematic setting of the Barents Sea gas infrastructure project. The numerical data is simulated to conform with the publicly available real values estimates (see, e.g., Gassco, 2014).

One gas transport solution assumes a pipeline of 32", which is suggested based on a medium resource scenario. The expected pre-tax NPV of the project is NOK 50 billion (€1 equals approximately 9 NOK) estimated by the traditional technique, using a risk-free rate of 2%. It is assumed that the option to expand can be exercised during the first 20 years of the pipeline operation. Assuming volatility equal to 10% a year ( $u = e^{\sigma\sqrt{t}} = 1.105$ ,  $d = 1/u = 0.905$ ), an event tree representing the dynamics of the project value over the 20-year period (21 different outcomes) is generated (Figure 4.1).



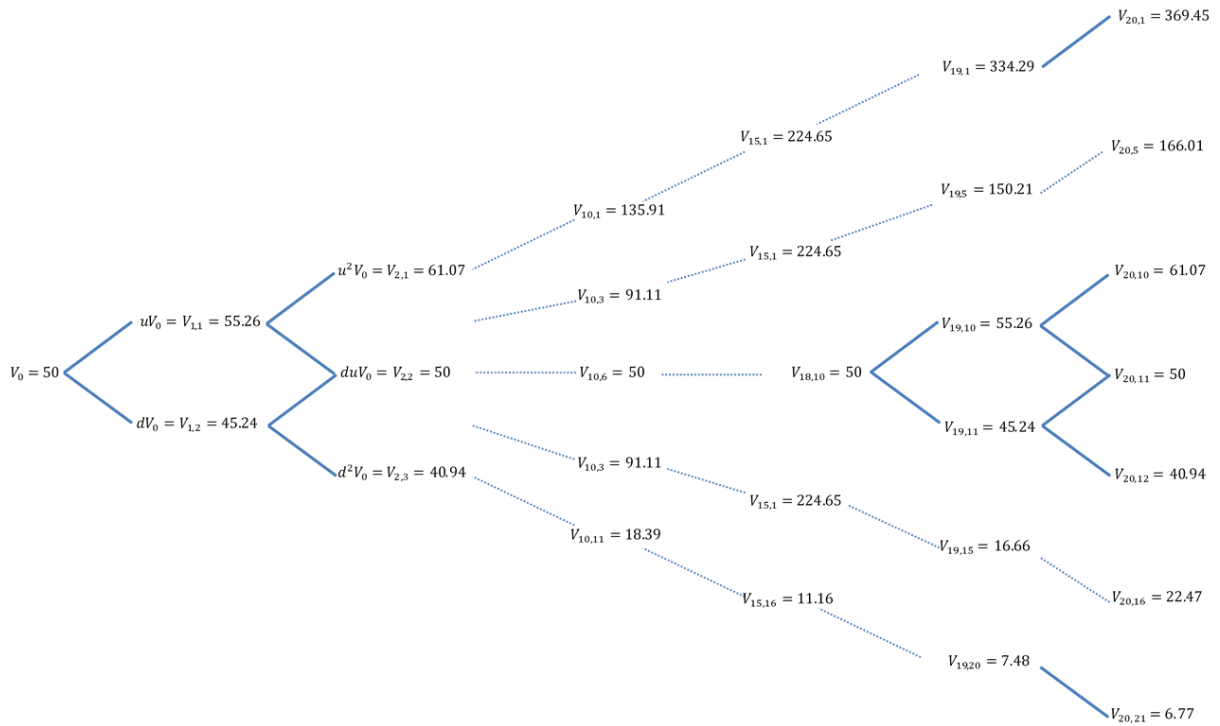


Figure 4.1 Event tree: value of the underlying asset

For an additional NOK 5 billion, the initial pipeline dimension can be increased to 42". This gives the option to expand gas production by 50%, if the rate of exploration success is high and market conditions are favourable. This option can be exercised for an investment of NOK 25 billion in the pipeline, the upgrade of processing facilities and the development of associated fields. The decision tree (Figure 4.2) is solved backwards to find the value of the project with flexibility. The calculated risk-neutral probability is  $p = \frac{e^{r\Delta t} - d}{u - d} = 0.575$ .

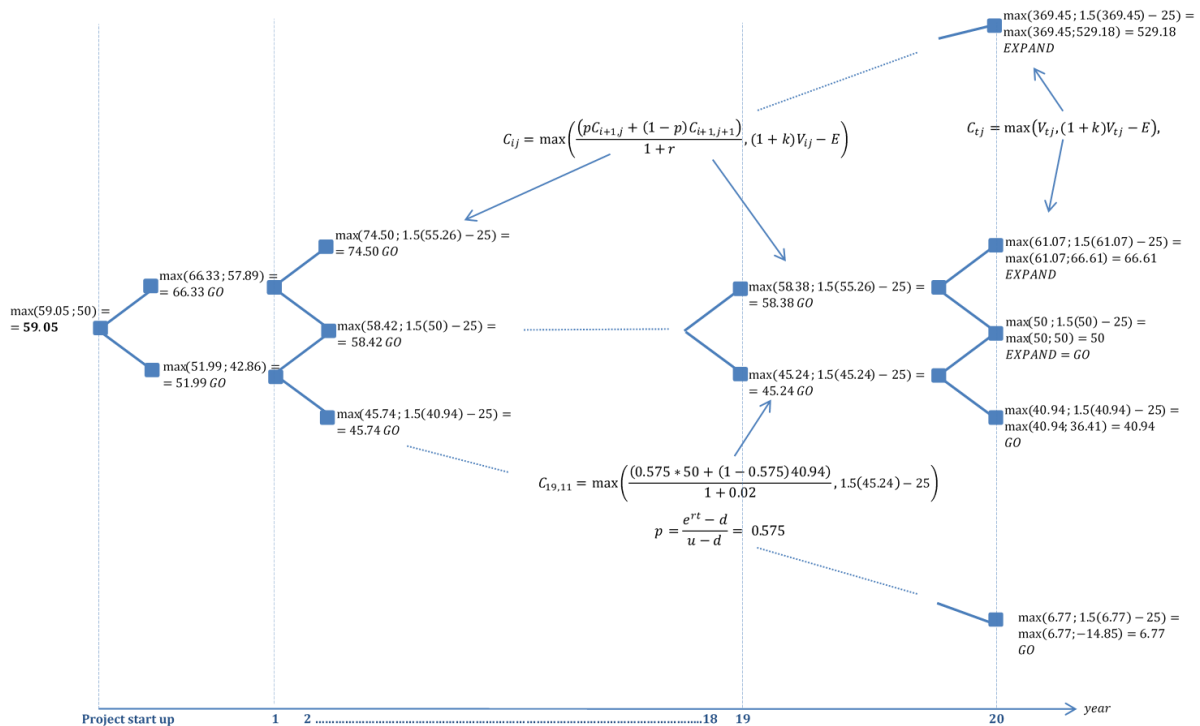


Figure 4.2 Decision tree for the option to expand

The value of the flexibility provided by the excess pipeline capacity is the difference between the initially estimated project value and the value obtained after solving the decision tree. In the example, the value of the flexibility provided by a pre-investment of NOK 5 billion is NOK 9.05 billion, meaning that the investments in excess pipeline capacity provide flexibility worth NOK 4.05 billion.

The value of flexibility gets higher if volatility increases. In the example, with  $\sigma$  equal to 0.2, the value of flexibility is NOK 12.85 billion. The size of a potential expansion also positively affects the value of flexibility; if the project can be scaled up to 60%, it increases up to NOK 13.61 billion. With a higher exercise price, expansion becomes less attractive and the value of flexibility decreases, i.e. an expansion cost of NOK 30 billion gives a value of flexibility equal to NOK 6.77 billion.

## 5 Value of Flexibility in Project Appraisal

Trigeorgis (1996) suggests a framework for investment appraisal where the project value, or the expanded (strategic) NPV, consists of an additive expansion of the traditional static NPV with various option premiums:

$$\text{Expanded (strategic) NPV} = \text{Standard (static) NPV} + \text{Option Premiums}$$

In this framework, the abovementioned trade-off between two viewpoints on the project (the investor and the public decision-maker) is reflected, among other aspects, in the focus on different option premiums. A project investor interested in finding a transportation solution for a set of well-defined fields does not have the incentive to account for flexibility provided by

excess pipeline capacity. However, the investor is interested in the value of destination flexibility, which in practice is accounted for by using a price premium for a unit of sold gas. According to some estimates (e.g., Gassco, 2014), it may be up to 10% of the market price of the pipeline gas. Rodríguez (2008) suggests an approach for real options valuation of the destination flexibility of LNG. The author compares a base case where the LNG flow is directed only to the EU market with a free destination case, in which the flow can be directed also to the North American market. Using the geometric Brownian motion process to model the stochastic gas prices, the author finds a 21% improvement in the value of the LNG flow in comparison to the expected value without destination flexibility.

From the perspective of a public decision-maker, both the destination flexibility of LNG and the flexibility provided by excess pipeline capacity are of interest, because both contribute to the social surplus created in the sector. Therefore, both values should be included in the socio-economic appraisal of upstream gas transport infrastructure projects, if an LNG and pipeline alternatives are considered. Shaton (2015) proposes an approach for a comprehensive socio-economic appraisal of upstream gas infrastructure projects, which accounts for these two types of flexibilities.

Literature showing the importance of using real options analysis in public decision-making is on the increase. Livermore (2013) discusses the application of the real options theory for public decision-making in the petroleum industry. He argues that the consideration of real options is necessary to maximise economic returns from non-renewable natural resource extraction, using the example of offshore oil drilling in the United States (US) as a case study. The author claims that the cost-benefit analysis of the economic consequences of leasing offshore lands performed by the responsible authority and the existing bidding system fail to account for real option value, thereby failing to maximise the net benefits generated by this public resource. He states: 'Ultimately, planning and leasing decisions are being made without estimations of option value, and private market actors do not have incentives to adequately consider several of the central uncertainties that are relevant to society in general' (Livermore, 2013, p. 637). Revesz (2014) also concludes that the quantification of real options can meaningfully affect the outcomes of agencies' cost-benefit analyses and recommends adapting real options techniques used by US government agencies to evaluate the exploitation of natural resources. It should be noted that both authors consider only the values of delaying the decisions.

The following simulated numerical example (Table 5.1) demonstrates how the real options valuation of excess pipeline capacity may be used in a socio-economic appraisal of an upstream infrastructure project, based on the structure proposed in Shaton (2015). This example extends the discussion of the Barents Sea Infrastructure Project mentioned in the previous section: there is an LNG solution of the exact capacity needed to transport gas from the existing discoveries, and a pipeline solution with two alternative capacities. There is no economies of scale in LNG investments; hence, there is no reason for pre-investments. A 32" pipeline corresponds to the existing volumes; a 42" pipeline requires pre-investments, but allows for a cost-efficient expansion of the system in the future.

At the initial stage of the analysis, only the existing fields and discoveries are included, giving the expected revenue from selling the pipeline gas as NOK 70 billion, excluding the production costs. The expected revenue for the LNG alternative is 5% higher due to the destination flexibility. The LNG solution requires NOK 14 billion of initial investment (CAPEX), while the costs of the sea shipping accounts for an additional NOK 14 billion (OPEX) over the lifetime of the project, which corresponds to the expected lifetime of the fields in question. The 32" pipeline solution requires an initial investment of NOK 20 billion; the 42" requires NOK 5 billion more. There are regulated tariffs for pipeline transportation in Norway, which consist of a

capital element and an operating element.<sup>2</sup> The operating element is calculated annually and covers the operating costs of running a facility. The capital element should cover the investment cost with a 'reasonable' return on the capital invested during the lifetime of a license (historically, 7% before tax). The capital element represents the revenue for the investors/owners of the infrastructure. The total tariff paid by the shippers for the transportation in the new 32" pipeline is NOK 27 billion (NOK 22 billion as the capital element and NOK 5 billion as the operating element). The capital element of transportation via the 42" pipeline is higher due to the pre-investments. Therefore, the total tariff paid for transportation via this pipeline is NOK 32 billion. Due to the difference between the rate of return on the investment (7%) and the social discount rate (4%), the net income for investors in the pipelines is positive, equal to NOK 2 billion. The shipper will also use the existing network downstream; thus, the total tariff paid is NOK 4 billion. Comparing the NPV (4% discount rate) of the alternatives from the project-economic perspective, the LNG solution is better: NOK 45.5 billion vs. NOK 41 billion for the 32" pipeline and NOK 36 billion for the 42" pipeline.

Expanding the evaluation framework, the planner includes the effects on the rest of the transportation network. The inflow of gas from the new pipeline into the existing downstream network brings additional income to its owners (the capital element of the tariff paid by shippers, NOK 3 billion) and reduces the operating element of the tariff for the shippers (a savings of NOK 1 billion). The prospects for future tie-ins are included in the analysis as an option value of flexibility provided by excess capacity (NOK 9 billion, approximated from the previous example).

Though this aspect is not covered in this paper, it should be noted that infrastructure projects in the gas sector may have significant externalities, such as environmental impacts, impacts on fisheries and shipping, which should also be taken into consideration in a complete socioeconomic evaluation of a project.

*Table 5.1 Example of a project valuation with simulated numbers (NOK in millions, 4% discount rate)*

Cash Flows	LNG solution	Pipeline 32"	Pipeline 42"
Shippers in the new infrastructure			
Revenue (excl. production costs)	70000	70000	70000
Value of destination flexibility	3500	0	0
Tariff in the new infrastructure	0	- 27000	-32000
Tariff in the downstream network	0	- 4000	-4000
Cost of shipping	- 14000	0	0
Investors in the new infrastructure			
Investment costs	-14000	-20000	-25000
Tariff revenue (capital element)	0	22000	27000
<b>TOTAL FOR THE PROJECT</b>	<b>45500</b>	<b>41000</b>	<b>36000</b>
Shippers in the existing infrastructure			
Owners of the existing infrastructure	0	3000	3000
Option value of flexibility	0	0	9000
<b>TOTAL FOR THE SHELF</b>	<b>45500</b>	<b>45000</b>	<b>49000</b>

<sup>2</sup> Regulations relating to stipulation of tariffs, etc. for specific facilities, 20 December 2002, No. 1724.

Including the effects on the shippers and owners of the existing infrastructure, the NPV of both pipeline solutions improve by NOK 4 billion, while the LNG's NPV remains unchanged. However, for the existing resource base, the LNG solution is still marginally better. Taking into account the possibility of expanding the transportation system and connecting new fields (if they are discovered) in the future and if market conditions are favourable due to pre-investments in excess capacity, the 42" pipeline becomes the favourable solution.

This example shows that the evaluations of a project from the project-economic and the NCS perspectives may lead to opposite recommendations. The participation of the independent system operator in the infrastructure planning on the NCS ensures that the effects on the existing network are taken into account; however, the value of flexibility in the pipeline investments has not been directly quantified and included in the analyses thus far. The presented example shows that this value can be estimated numerically and used in project appraisals.

## 6 Conclusion

Real options theory is a means to structure and value flexible strategies to address uncertainty. Real options is a particularly appealing concept when capital intensive irreversible investments must be undertaken under great uncertainty. In the case of gas transport infrastructure projects, multi-billion investment decisions are made under the uncertainty of gas prices and highly inexact knowledge of the long-term resource base. Infrastructure developments on the NCS are financed by petroleum companies, which need transport solutions for their gas fields. In order to ensure that the effects of new infrastructure development on the existing transportation system and the overall value creation on the NCS are taken into account, the development of the transportation network is coordinated by an independent system operator. Among other aspects, the system operator considers each infrastructure facility from a long-term perspective and evaluates possibilities for future tie-ins.

Due to high economies of scale, investments in excess pipeline capacity present the possibility for cost-efficient connections in the future. When an LNG and a pipeline solution are considered, a trade-off arises between the destination flexibility of an LNG and strategic flexibility provided by excess pipeline capacity. The destination flexibility of an LNG can be easily included in the project evaluation as a price premium for the unit of sold gas. The task of estimating the monetary value of flexibility provided by excess capacity is not straightforward. This paper demonstrates how real options analysis can be applied to estimate the value of flexibility in gas pipeline investments, and how this value can be used by a public decision-maker in the project evaluations.

The simulated example demonstrated the importance of real options valuations in upstream gas pipelines investments. The inclusion of the value of flexibility provided by excess pipeline capacity may change the outcome of investment appraisals. It should be noted that the framework by Trigeorgis (1996) mentioned above allows for the inclusion of various real options in extended NPV calculations. Among others, there might be an option to delay the decision, or an option to expand the system stepwise by new tie-ins of different sizes, which represents a compound option.

Considering investments in excess pipeline capacity through the lens of real options analysis has some limitations, as it cannot incorporate such effects as increased value creation onshore due to the expansion of petroleum activities. However, the real option value can serve as a

good proxy of the value of the excess pipeline capacity and play an important role in project evaluations.

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**Paper 3**

**Incentive problem in upstream gas transport infrastructure  
development**

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# Incentive problem in upstream gas transport infrastructure development

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## Abstract

The objective of this paper is to propose an analytical structure to investigate the interaction between the existing tariff regime and the investment behaviour in the Norwegian gas transport sector. A sequential game between the government, which determines the tariff regime, the transportation system operator, which suggests the capacity of the pipelines, and a gas company, which makes the final investment decision and chooses between a pipeline and a liquefied natural gas (LNG) infrastructure is used to derive the conditions, under which the socially preferable outcomes are achievable. The proposed analytical structure emphasises the relative advantages of the LNG and pipeline solutions: the price premium due to the destination flexibility of the LNG and economies of scale in the pipeline investments, which enable over-dimensioning of the pipelines with regard to future tie-ins. The independent system operator's special position in infrastructure development is discussed.

**Keywords:** *Natural gas; Infrastructure; Regulation; Investments; Incentive problem*

# 1 Introduction

Petroleum activities represent the largest industrial sector in Norway. In 2015, it accounted for 15% of the gross domestic product (GDP) and 26% of total investments (Statistic Norway, 2016). The share of investments in pipelines and terminals was 13.69% of the total, which is not the main contributor to the total investments in the sector. In comparison, development wells accounted for 40.4%. However, for the natural gas value chain, the transport infrastructure is a critical element. Investments in a new transport infrastructure represent a significant part of the total costs of a development project, while available transportation solutions drive exploration and subsequent developments of new gas fields. Timely development of a transport infrastructure on the Norwegian continental shelf (NCS) becomes even more important, as the share of natural gas in the total petroleum production is steadily growing. In 2015, the share of natural gas exceeded 50% of the total production of oil equivalents (Norwegian Petroleum Directorate, 2016).

However, infrastructure investments will not be undertaken if the regulatory regime does not ensure appropriate conditions to recover the invested capital. In 2013, the Norwegian government decided to reduce the capital element of the transportation tariff in the majority of the existing transport facilities by 90% for the volumes transported and handled from gas year 2016. As announced by the Ministry of Petroleum and Energy, the reasons for such a decision were that the tariff reduction would increase incentives for exploration in mature areas and the development of new infrastructure from the new exploration areas, reduce the threshold for the development of marginal resources, and increase extraction in the tail-end phase (Ministry of Petroleum and Energy, 2013). This decision raised a surge of discontent among the owners of the infrastructure, because of a dramatic decrease in the expected return on the infrastructure investments. Important questions are whether the existing system provides sufficient perspectives for investment cost recovery for the new infrastructure projects, and the implications that the 2013 decision may have on the gas transport sector in the long run.

Since the process of the liberalisation of the European Union (EU) gas markets started (the first EU Gas Directive was adopted in 1998), the problem of designing an optimal tariff structure and capacity allocation procedures for gas transportation has received considerable attention from both from policymakers and researchers. Among the earliest examples of theoretical contributions to the problem of optimal transportation tariffs in the liberalised gas markets is the paper by Cremer and Laffont (2002). In their paper, optimal gas transportation pricing and the transmission network dimension are derived for cases of perfect and imperfect competition. The network dimension, specifically excess pipeline capacity, is considered a suitable regulatory response to the market power of the local gas companies. Pelletier and Wortmann (2009) discuss whether the current tariff policy and uncertainty about supply and demand provide sufficient incentives for transport capacity investments. Using a multi-stage linear program, the authors simulate the repartition of the gas flows in the EU market in order to evaluate the risks of negative present value for the infrastructure investments. Gasmi and Oviedo (2010) derive optimal transport charges set by a regulator to maximise social welfare, given different forms of competition in the output between an incumbent and the marketer in a downstream gas commodity market. Lochner (2011) suggests a modelling approach to identify the transport infrastructure bottlenecks in the EU gas market and quantify their economic costs in order to ensure optimal investments in transport capacity. Another aspect of regulation in the EU gas transport sector, namely the balancing rules, is investigated by Keyaerts et al. (2011). This paper discusses the trade-offs between two ways of using gas pipelines, transport and short-term line-pack storage, which gives shippers and system operators flexibility with balancing supply and demand. The authors identify distorting effects to the gas market due to inadequate regulation of line-pack flexibility, because the existing balancing rules disregard

the sunk cost of using pipelines for storage. Chaton et al. (2012) analyse how the gas release programmes – a measure that has an incumbent release part of its gas to a marketer – advocated by the European Commission and transport infrastructure investments affect competition in gas markets. Their empirical analysis shows that combined with network expansion, gas release programmes under regulatory control are effective policies for promoting competition in the gas market.

The United States (US) natural gas sector was considered competitive long before the EU started the liberalisation process; however, the problem of designing optimal regulatory mechanisms to ensure sufficient incentives for investing in transport infrastructures is also relevant. For example, McAfee and Reny (2007) analyse how the application of market-based transportation rates for interstate pipelines effect the efficiency of gas transportation services. In particular, the authors discuss how to determine the minimum excess capacity on rival pipelines that can prevent a company from exercising market power if market-based transportation rates are approved. Von Hirschhausen (2008) provides an extensive literature review on the historical and current discussion about the relationship between infrastructure investment and regulation/competition, and applies the findings to a case study of the link between restructuring and infrastructure investments in the US natural gas sector. The author finds that there is little cause for concern about infrastructure investments, resource adequacy, or supply security in the US gas market, although some improvements in the regulatory framework may enhance investments.

The gas markets in the EU and the US have their own specific features; therefore, the theoretical developments for these markets have limited application to the problems arising in the Norwegian gas market, which is export-oriented with almost negligible domestic consumption of natural gas. As von Hirschhausen (2008, p. 9) emphasises, for the investment implications of regulation, 'clear one-size-fits-all answers are not possible', and 'case-specific assessments are still needed to derive concrete, applicable policy conclusions'.

The literature on tariff regulations in the Norwegian gas transport sector is rather limited. Hagen et al. (2007) discussed optimal tariffs in the case where the transport facilities are owned by a national gas producer with a public ownership share. The main assumption in this analysis is that the national appropriation of the resource rent through taxation is incomplete, and the question is to what extent it would be optimal to harvest some of the rents through the transportation tariffs. The derived optimal scheme is based on a modified Ramsey rule, and differentiates domestic and international shippers. Sannarnes (2007b) derives an optimal tariff in a network owned by a syndicate of gas producers. The optimal tariff structure required differentiated tariffs for the network owners and the third party. Sannarnes (2007a) discusses how a government can design socially optimal investment mechanisms to increase capacity in a gas transport network owned by a syndicate of gas producers. The identified preferable investment mechanism to allocate capacity is based on Vickrey's second-price auction combined with regulated tariffs equal to marginal costs. Xu (2010) discusses how the restructuring of Norway's gas sector in 2002 affected the development of the transport infrastructure. It was found that in the restructured sector, petroleum companies may limit the capacity of the new pipelines and challenge future network expansion.

Recent changes in the ownership structure in the sector and the growing importance of the liquefied natural gas (LNG) trade raise the need for further study on the regulation and investment incentives in the Norwegian gas transport sector. The objective of this paper is to build an analytical structure to understand and explain the system of investment incentives in the Norwegian gas transport sector under the existing tariff regime. A simple model is developed in order to analyse how the tariff structure incentivises investments in the pipeline and LNG infrastructure on the NCS. Special emphasis is given to analysing the role of the independent system operator within the existing incentive structure.

The paper is organised as follows. Section 2 describes the research problem on the basis of the ongoing discussion of an infrastructure development project on the NCS. In Section 3, the game of infrastructure developments is presented. Model implications are discussed in Section 4. Section 5 concludes the paper.

## 2 Problem description

The southern part of the NCS is a mature petroleum province with an extensive transportation network. The regulatory objective for this part of the shelf is to ensure high utilisation of the existing infrastructure, which may become an acute issue in light of an expected drop of gas inflow in certain pipelines in the coming years. In order to achieve this objective, a low tariff for access to the transport infrastructure is required. A low cost threshold due to a low transportation tariff may also incentivise development of the marginal fields in the mature areas.

The northern part of the shelf is much less developed, but exploration interests of petroleum companies have moved further to the north of the Norwegian Sea and the Barents Sea. This establishes a need for further development of the transportation network. At the moment, the only transport solution available in the northern part of the NCS is the LNG facility at Melkøya that receives, processes and liquefies gas from the Snøhvit field in the Barents Sea, which is then transported to markets by sea-going vessels. The operator of the field considers the expansion of the production and, accordingly, the expansion of the LNG facility. The main advantage of this solution is market flexibility – the producer is not locked into the European market and the gas can be shipped to the highest value market. In addition, the investment costs for an LNG chain are relatively low, although the operating costs will be high compared to pipeline transportation.

A wide debate about a new transport infrastructure project in the Barents Sea (BSGI) began in 2012, when Gassco, the independent gas transport system operator, initiated a discussion about the possibility of a major pipeline infrastructure in the area that would connect the Barents Sea with the existing pipeline network. A pipeline solution requires higher initial investments, lacks destination flexibility, but implies operating costs that are considerably lower than the LNG operating costs. An important advantage of the pipeline solution is a significant economies of scale in investments. This means that a major pipeline solution can be established in order to connect several discoveries in the area, thereby sharing the investment costs between several gas producers. Also, the additional costs to establish excess capacity above the committed volumes, with regard to future discoveries, are low. Available spare pipeline capacity in the transport system provides incentives for exploration in the region and reduces the cost threshold for development of deposits along the pipeline. However, according to the study conducted by the system operator (Gassco, 2014), the existing resource base is not sufficient to justify the investments in a pipeline infrastructure. However, if the potential outcome of near-term (three years) exploration activities in the Barents Sea are taken into consideration, the pipeline becomes the preferable solution.

According to the existing regulatory framework, a transport facility, which is not field-dedicated and where third-party access is assumed, should be operated by a neutral and independent system operator. In practice, new major pipelines, e.g. Polarled pipeline, which comes on stream in 2017, become part of the Gassled joint venture, which is the formal owner of most of the pipeline infrastructure on the NCS, and fall under the operatorship of the independent system operator, the state-owned company, Gassco. The pipeline investors obtain participation interest in Gassled according to the value of their investments, and receive

payback through the capital element of the transportation tariff paid by the shippers. The tariffs are stipulated by the Ministry of Petroleum and Energy according to the tariff regulation<sup>1</sup> and consist of a capital and an operating element. The capital element is stipulated such that the owner of a facility can expect a reasonable return on the capital invested. Historically, the rate of return was 7% before tax. The operating element is stipulated based on full cost recovery. In light of a high internal rate of return in the petroleum industry, infrastructure investments are not generally regarded by gas companies as profitable investments, but rather as a cost of a deposit development. However, the companies had non-monetary incentives to participate in infrastructure projects. Before 2010, petroleum companies had preferential rights to book pipeline capacity up to 200% of their participation interest in the pipeline in question. When the preferential rights were abolished, the gas companies preferred to re-direct the capital tied-up in the infrastructure investments to their core activities. Several large gas producers sold all their shares in Gassled to financial companies, such as pension funds and other investment vehicles. The availability of such a market for the investments allows for considering the transport infrastructure separately from field development, as an independent investment project with a relatively stable return provided by the tariff revenue. Therefore, a gas producer considering development of a transport infrastructure sees it as both a shipper and as an investor. Because of this dualistic nature, a trade-off arises with regard to the tariff. As an investor, the gas producer would prefer a tariff with a high capital element; as a shipper, the company would prefer a low tariff.

When evaluating a new infrastructure project, a public regulator considers the effects of the new infrastructure facilities on the rest of the transport network and the value creation on the NCS in general. It should be noted that the availability of a transport infrastructure alone does not incentivise exploration and development of new deposits along the pipeline. Rather, the availability of spare transport capacity makes exploration and development more probable. Therefore, with regard to potential further development of petroleum activities, it is important to establish excess pipeline capacity in the new infrastructure. However, gas companies, participating in an infrastructure project to ensure a means to evacuate the gas from their fields (a shipper perspective) are not willing to invest in excess pipeline capacity. However, a sufficiently high capital element of the tariff may incentivise a gas company to act as an investor and participate in such investments.

In the incentive problem described above, the independent system operator plays an important role. According to the framework conditions, Gassco acts in a neutral manner, ensuring an efficiently run transport system for the benefit of owners and users. Among the tasks assigned to the system operator by the Petroleum Act<sup>2</sup> (Section 4-9) is development of the transport system. Gassco operates on a no profit no loss basis and does not invest in infrastructure projects. Regarding the development of the transport system, Gassco has the role of a coordinator or 'architect' of the expansion of the network. Gassco's task is to assess the need for new transport solutions, and recommend optimal capacity, routing and connections to existing facilities onshore and offshore. Development of the new infrastructure is referred to as Gassco's responsibilities on behalf of the government; at the same time, the infrastructure is funded by gas companies and, if third-party access is assumed, becomes a part of Gassled. On the one hand, Gassco should follow the government's objective, which is to provide sufficient transport capacity in order to ensure a well-functioning gas market in the long-run. Additionally, Gassco should also consider the interests of the infrastructure owners. Within the framework of the principal-agent theory, this situation can be considered common agency (see, e.g., Dixit et al., 1997; Peters, 2001). According to Bernheim and Whinston (1986), common

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<sup>1</sup> Regulations relating to stipulation of tariffs, etc. for specific facilities, 20 December 2002, No. 1724.

<sup>2</sup> Act relating to petroleum activities (the Petroleum Act), 29 November 1996, No. 72.

agency is when the actions chosen by the agent affect several other parties (the principals) whose preferences for the possible actions of the agent typically conflict. In the case of gas infrastructure development on the NCS, Gassco is an agent whose choices affect two principals – the government and the infrastructure owners – with different preferences regarding infrastructure development. In the relevant literature (see, e.g., Hagen et al., 2007; Xu, 2010), the system operator's decisions regarding infrastructure development on the NCS are typically not distinguished from the government's decisions. In this paper, the system operator's objectives and choices are considered separate from those of the government.

### **3 The game of infrastructure development on the NCS**

#### **3.1 Players and their strategies**

The problem described above determines the setting of the game presented in this section. The set of players consists of: a government that sets up the tariff regime; a gas company that decides whether to invest in a pipeline infrastructure or in an LNG facility; and a system operator that suggests the capacity of the pipeline solution.

##### **3.1.1 The government**

In order to ensure the efficiency of the gas transport market, the government simultaneously pursues two goals: (1) to ensure high utilisation of the existing transport network; and (2) to motivate further infrastructure development. The existing regulation prohibits tariff discrimination (neutral access requirement by the European Economic Area [EEA] Agreement) and reduces the government's ability to directly adjust the tariff. The tariff is stipulated according to the formula established in the tariff regulation. However, the government can manipulate the construction of the capital element of the tariff. The capital element in the tariff formula may be changed through the change of the rate of return and/or change in the length of a payback period, which corresponds to the lifetime of the pipeline licence. Formally, these changes lead to the increase or decrease of the tariff. Therefore, the government's strategies are to set up a tariff  $T_H$  with a larger capital element, i.e. a shorter payback period and/or a higher rate of return, or to set up a tariff  $T_L$  with a lower capital element, i.e. a longer payback period and/or a lower rate of return. A lower tariff means lower transportation costs for shippers, resulting in higher utilisation of the existing network. However, a lower rate of return on investments raises incentive problems for investing in a new pipeline infrastructure. A higher tariff works in the opposite way in that it incentivises infrastructure development but reduces utilisation of the existing network.

The objective function of the government is naturally defined as social welfare maximisation through tax income and the state's participating interest in petroleum activities (see, e.g., Hagen et al., 2007). For the purpose of this analysis, it can be simplified and expressed as maximisation of the total gas flow (Xu, 2010). Presumably, the larger the volume of transported gas, the higher the state income. This formulation of the objective function reflects both goals of the government: the gas flow is maximised both as a result of increased utilisation of the existing pipeline network and new infrastructure development.

##### **3.1.2 The system operator**

For the purpose of this model, the system operator's decisions are restricted to determining the capacity of the planned transport facility, particularly the size of the excess capacity. As an agent of the government, it should pursue social welfare maximisation and place a preference

on planning sufficient excess capacity with respect to the expected growth rate of production. As an agent of infrastructure owners, the system operator should plan capacity corresponding to the volumes of gas in the existing discoveries.

An independent system operator does not receive any profit from its activities. Thus, defining its objective function is not straightforward. This model assumes that the objective of the system operator is to minimise the total costs of gas transportation on the NCS.

### **3.1.3 A company**

Usually, a group of companies holding licenses for the discoveries in the relevant area initiates a new transport facility development, applies for the corresponding pipeline license and invests in the project. One company is appointed as an operator and acts on behalf of the licensee. Therefore, the player 'company' represents the group of gas producers involved in the project. The company makes the final investment decision and defines the transportation solution: a pipeline or an LNG solution. The option not to invest is not considered, as a transport solution is an integrated part of gas field development, and a decision not to invest in a transport infrastructure would mean termination of field developments.

The company's objective function is profit maximisation. The choice between the pipeline and the LNG depends on the relative cost advantages of both solutions: the LNG requires less than the pipeline initial investments, but implies higher operating costs; in addition, the LNG solution implies a price premium due to destination flexibility.

## **3.2 The game of infrastructure development**

In the game, the described decisions are represented by sequential moves. The government moves first and sets up the tariff regime. In practice, a company initiates the planning process of a particular transport facility. The choice of a solution concept is made in close collaboration between the licensee and the system operator. In the model, the decision of the system operator is placed before the company's to indicate that the final investment decision is made by the company, which may prefer an LNG solution, if the pipeline solution recommended by the system operator is unacceptable from a commercial point of view.

There is uncertainty over the resource base, which is modelled as two possible resource scenarios: low and high. It is assumed that the 'nature' moves before the government and determines the resource scenario. The probability of each resource scenario is common knowledge. The players can observe the actions of the other players. The parameters used in the model are listed in Table 3.1.



Table 3.1 Parameters used in the model

Notation	Meaning
$P$	Production rate of the field(s) in question, the minimum capacity of the new pipeline
$Q$	Throughput of the existing transport system
$F$	Fixed cost to develop a pipeline of capacity $P$
$\alpha$	The increase of the production rate in the area of the field(s) in question in the case of the resource scenario Low, $0 \geq \alpha > 1$
$\beta$	The increase of the production rate in the area of the field (s) in the case of the resource scenario High, $0 > \beta \geq 1, \beta \gg \alpha$
$\gamma$	The increase of the production rate on the NCS due to a low tariff, $\gamma > 1$
$\Delta F$	Fixed costs to establish excess capacity of size $\alpha P$ or $\gamma P$ ; to establish excess capacity $\beta P$ costs $2\Delta F$
$c$	Operating cost of a pipeline of capacity $P$
$R$	Revenue of the company from the field(s) in question
$\Delta R$	Additional revenue of the company due to destination flexibility of LNG
$\mu$	Cost ratio of LNG and pipeline solutions, $\mu > 1$
$\eta(r, t)$	Fraction of fixed cost recovered, a function of the rate of return and a payback period
$p_1$	Probability of the resource scenario Low

It is also assumed that: (1) demand is always sufficient for all produced gas; (2) the fixed cost for the LNG solution is  $F/\mu$ , variable costs are proportionally higher,  $\mu c$ ; (3) if the established capacity is not sufficient, then a new pipeline is built at a cost  $F$ , and it suffices to transport  $\alpha\gamma P$  or  $\beta\gamma P$  of gas and does not assume overcapacity.

According to its architect role, the system operator is not likely to plan capacity of a pipeline exactly equal to production rate  $P$  of the field in question, but takes into account possible discoveries in the area and recommends solutions with excess capacity, either  $(1 + \alpha)P$ , corresponding to the resource scenario Low (lower bound for  $\alpha$  is set equal to 0, allowing for the possibility of zero expectation over future discoveries in the area), or  $(1 + \beta)P$ , corresponding to the resource scenario High. The system operator observes the action of the government and adjusts its plans in accordance to the established tariff regime. The low tariff  $T_L$  means lower total costs, resulting in a general increase of gas production on the NCS to  $\gamma$ . Therefore, in the case of  $T_L$ , the system operator plans either  $\gamma(1 + \alpha)P$  or  $\gamma(1 + \beta)P$ .

Figure 3.1 depicts the game tree. The 'nature' move is omitted in the figure; the uncertainty is taken into account while constructing the payoffs.

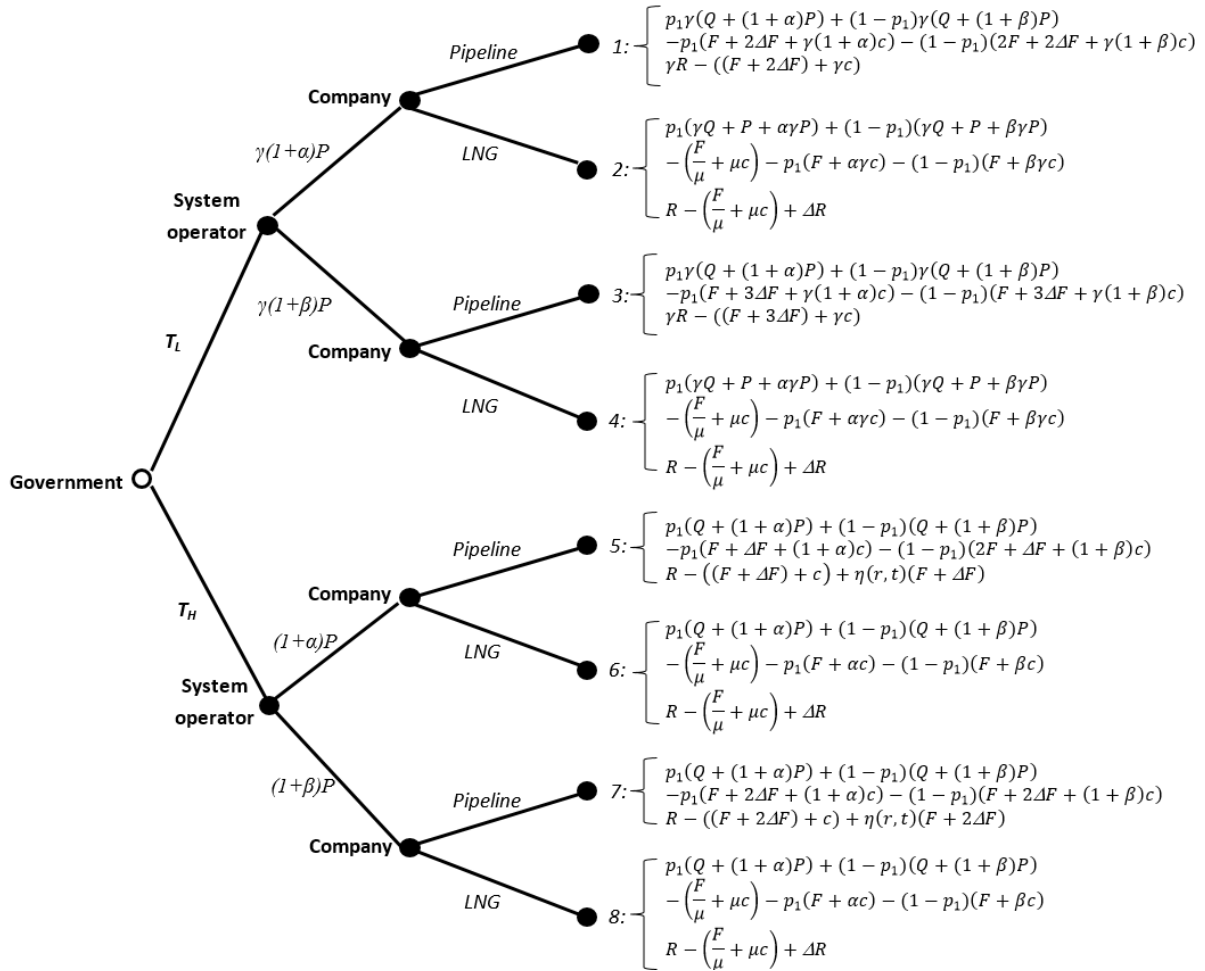


Figure 3.1 The game tree. The payoffs are listed in the following order: Government, System operator, Company.

The next subsection explains the reasoning behind the payoffs of the players.

### 3.3 Payoffs and outcomes

#### 3.3.1 The government

The gas flow in the transport system is the sum of the throughput in the existing network (representing the first ‘sub-goal’ – utilisation of existing network), the gas flow in the newly built pipeline (the second ‘sub-goal’ – network development) or the volume transported as LNG, weighted upon the probabilities of the resource scenarios. Under the high tariff, if the capacity of the established pipeline is not sufficient, then another pipeline is to be built at a cost  $F$ . If the low resource scenario occurs and excess capacity  $\beta$  was established, then, there is underutilised capacity in the network. If the company decides to build an LNG without excess capacity and the opportunity for third-party access, the infrastructure needed by the other companies (LNG or pipelines) is to be built by other companies. All the gas that is needed to be transported will be transported; therefore, the payoff for the government is the same for nodes 5–8. For the low tariff case, the payoffs are constructed in the same manner, with the difference in the market response to tariff reduction  $\gamma$ : volumes of gas transported as LNG are not affected by tariff reduction (nodes 2 and 4).

### 3.3.2 The system operator

The payoff of the operator is the sum of the investment and operating costs, weighted upon the probabilities of resource scenarios. If the government sets up tariff  $T_L$ , the company decides to build a pipeline and the resource scenario Low occurs – the investment cost is  $F + 2\Delta F$ , variable cost is  $\gamma(1 + \alpha)c$ . If the scenario High occurs, the established capacity is not sufficient and a new pipeline is needed, resulting in a fixed cost equal to  $2F + 2\Delta F$ . The variable cost in this case is  $\gamma(1 + \beta)c$ . If the system operator recommends larger capacity  $\gamma(1 + \beta)P$ , the investment cost is  $F + 3\Delta F$  for both scenarios, and variable costs are  $\gamma(1 + \alpha)c$  and  $\gamma(1 + \beta)c$  for Low and High scenarios respectively. If the company decides to opt for the LNG solution, then a pipeline of capacity  $P$  with investment cost  $F$  is built by other companies to transport the volume  $\alpha\gamma P$  or  $\beta\gamma P$  of gas from their discoveries in the area with corresponding variable costs. For the lower branch of the tree, the payoffs are constructed in the same manner.

### 3.3.3 The company

The payoffs for the company are defined as the difference between the revenue  $R$  and total costs, assuming the option premium for destination flexibility of an LNG solution  $\Delta R$ . In the lower branch of the game tree, the company pays total investment costs to build a pipeline of either capacity  $(1 + \alpha)P$  or  $(1 + \beta)P$ , but uses only  $P$ , having variable cost  $c$  in both cases. In the upper branch, the company pays the full cost to establish a pipeline capacity  $\gamma(1 + \alpha)P$  or  $\gamma(1 + \beta)P$ , but uses only  $\gamma P$  with the associated variable cost  $\gamma c$  and receives an increased revenue  $\gamma R$ .

The lower branch of the game depicts the tariff regime with a higher rate of return. These conditions allow the company to consider investment costs as partially recoverable. A part of fixed costs  $\eta(r, t)F$  is subtracted from total costs in the outcomes 5 and 7. The rationale behind this is the availability of the second-hand market for the infrastructure investments. The increased rate of return expands this second-hand market, providing an opportunity for the company to recover pipeline costs more easily. Certainly, this second-hand market exists under both tariff regimes, but for simplicity,  $\eta(r, t)F$  is introduced only under the high tariff, underlining considerably higher willingness to pay for the participation interest in the infrastructure assets by investment vehicles. The outcomes for the nodes 2, 4, 6 and 8 are the same, meaning that a lower tariff for the pipeline transportation does not affect the company's revenue if it chooses the LNG solution.

## 3.4 Results and findings

The dominant strategy of the government is to follow the path of the low tariff because of the expected increase of the throughput of the system. Under this tariff regime, the company evaluates infrastructure development only from the position of a shipper, considering the pipeline alternative as a large fixed cost of a field development. This is because as an investor, the company observes a low rate of return on investments and little opportunity to recover costs in the short run. In this situation, the question of excess capacity becomes problematic, because the company has no incentives to invest in capacities higher than needed for the existing discoveries,  $\gamma P$ . Under the low tariff, investment in excess capacity means only tied-up capital. The company's choice between nodes 1 (pipeline) and 2 (LNG) depends on the value of flexibility of LNG,  $\Delta R$ :

$$\Delta R < (\gamma - 1)R - \left( \left(1 - \frac{1}{\mu}\right)F + 2\Delta F \right) - (\gamma - \mu)c \quad (1)$$

If condition (1) is satisfied, gains from increased revenue due to low pipeline transportation costs and savings on variable costs minus losses on investment costs exceeds the premium for the destination flexibility of LNG. In this situation, the company chooses the pipeline solution and the game ends up at node 1. If the system operator suggests excess capacity  $\beta$ , the estimate for the value of LNG flexibility should be very low for the company to decide in favour of the pipeline, actually excluding node 3 from the set of realistic outcomes. Referring to the Barents Sea infrastructure project, a rather high estimate of  $\Delta R$  can be observed (up to 10% of the sales price of the pipeline gas, according to Gassco, 2014), determining the strong tendency for the game to end up with an LNG solution, which is less preferred from the socio-economic standpoint (lost  $\gamma P$  in the payoffs for the government).

A solution to the incentive problem is found in the lower branch of the game tree. If the government decides to follow the path of higher tariffs, it bears the loss of reduced utilisation of the existing capacity (lost  $\gamma$ ), and motivates the company to act not only as a shipper, but also as an investor. The shorter is the determined payback period and the higher the rate of return, the larger is the fraction of the investment costs,  $\eta(r, t)$ , which are considered recoverable.

In the case of the high tariff, the company takes into account the second-hand market for pipeline investments and makes the decision both from the point of view of a shipper and of an investor. If the system operator recommends excess capacity  $\alpha$ , the company has an incentive to invest in the pipeline solution if the following holds:

$$\eta(r, t) > 1 - \frac{1}{\mu} \frac{F}{F + \Delta F} - \frac{(\mu - 1)c}{F + \Delta F} + \frac{\Delta R}{F + \Delta F} \quad (2)$$

If condition (2) is satisfied, the incentive problem is solved, the company invests in the pipeline of the capacity  $(1 + \alpha)P$ , and the game ends up at node 5.

If the system operator suggests the pipeline capacity  $(1 + \gamma)P$ , the company chooses the pipeline solution if the following condition holds:

$$\eta(r, t) > 1 - \frac{1}{\mu} \frac{F}{F + 2\Delta F} - \frac{(\mu - 1)c}{F + 2\Delta F} + \frac{\Delta R}{F + 2\Delta F} \quad (3)$$

If condition (3) is satisfied, the game ends up at node 7.

The objective of the system operator was defined as minimisation of total transportation costs. Following this objective, the choice of the dominant strategy is based on expectations of Low and High scenarios occurring. From the point of view of cost minimisation, the LNG solution can also be preferred under certain relationships between variable and fixed costs. The common agency position of the system operator and assigned tasks makes its decision process more complex. The system approach for infrastructure development assumes planning for possible future connections, thereby providing incentives for exploration in regions with available transport solutions. In this regard, an LNG solution is not efficient because of low economies of scale and high operation costs.

Under the low tariff, the game has a tendency to end at node 2 or 4 with an LNG solution. However, condition (1) can still be satisfied if economies of scale of the pipeline overcome the

flexibility advantages of the LNG. The choice of pipeline capacity can be obvious if the probability of the resource scenario High is low: the system operator recommends the solution with excess capacity  $\alpha$ , which is acceptable for the company. If expectations of exploration success are high, then the common agency position of the system operator becomes explicit. In this situation, the solution with excess capacity  $\beta$  is cost efficient and goes in line with the objective of the government – gas flow maximisation in the long run due to increased incentives for exploration in the region. However, if the only feasible solution for the company is the one with excess capacity  $\alpha$ , the system operator should adjust its strategy and comply with another principal – the company. This solution is second best both for the system operator and for the government, but it is the only way to incentivise development of a pipeline and ensure development of the system in the long run.

If the government sets up a high tariff, the company receives incentives as an investor, and a pipeline solution becomes more attractive than the LNG. As a result, the incentive problem as such lessens, but the system operator has to balance between the principals if the company's willingness to invest does not correspond to the expected need for excess capacity. If condition (2) is satisfied, the system operator's choice of strategy  $(1 + \alpha)P$  goes in line with the company's interests, while the choice of  $(1 + \beta)P$  does not, and the system is again inclined to end up with an LNG solution. Only if the tariff regime makes  $\eta(r, t)$  large enough to satisfy condition (3), then there is no conflict of interest between the principals, and the system operator can choose strategy  $(1 + \beta)P$  without balancing between the principals. From the social welfare perspective, the outcome of node 7 is most preferable, when the rate of return is high enough to provide incentives to invest in sufficient excess capacity. The main drawback of this solution is that the government loses on the existing system utilisation because of the high tariff for the shippers.

There is a trade-off for the government to establish a transportation tariff low enough for shippers and high enough for investors. This twofold objective of the government reduces the efficiency of tariff regulation in relation to the incentive problem. A need arises for an additional coordination device in the infrastructure planning. The system operator, acting as a common agency, bears this responsibility. Observing the actions of the government, the system operator evaluates investment incentives and suggests solutions that are both feasible for the investor and beneficial for the state. The responsibility of a common agent is to ensure efficient interactions between the existing tariff regime and market-based incentives, and to reconcile any conflicting interests of the principals.

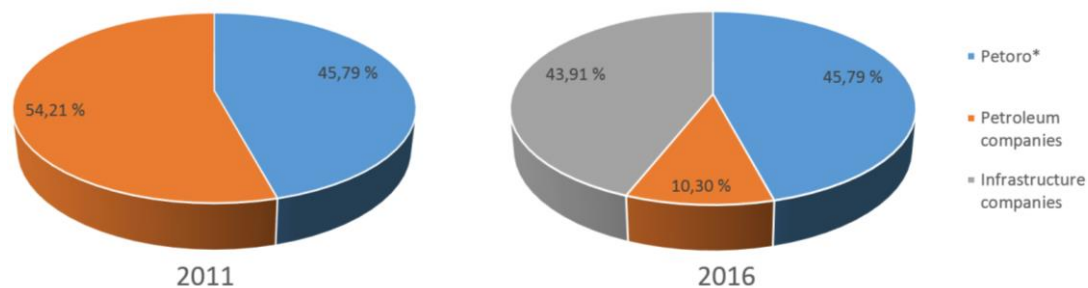
## 4 Model implications and discussion

The interpretation of the game for the state of the Norwegian gas transport market before the tariff reduction suggests that the government kept a rather high tariff, prioritising the infrastructure development goal. However, according to the model, a low tariff was the preferred strategy of the government, which was reflected in the tariff reduction in 2013. This decision was motivated by prioritising the utilisation of the existing infrastructure.

However, the changes of July 2013 relate only to the existing infrastructure and do not cover the newly built infrastructure. The government can ensure a high rate of return on new projects by having a lower one for the existing infrastructure. Such a strategy may have different implications. On one hand, lower tariffs in the southern part of the network provide incentives for petroleum activities in the north, even if the transport tariff in the newly built facilities is high. For example, the new pipeline planned for start-up in 2017, Polarled, will connect the fields in the Norwegian Sea to the processing facilities onshore at Nyhamna and the Langed export

transport system to Easington in the United Kingdom (UK, the Langed pipelines). According to the new tariff regime, the tariff for Langed will be close to short-term average costs, while the tariff for Polarled will be based on long-term average costs. However, the total transportation costs for gas produced up north will be lower than they could have been under the old tariff regime. On the other hand, such a solution may have a distortion effect on the utilisation of the newly built facilities: the route of the Polarled pipeline will partially go along the existing Åsgard Transport pipeline, which is fully utilised at the moment, but is expected to have spare capacity in the near future. If the tariff for transportation service via Polarled is considerably higher than via Åsgard, companies may prefer to postpone field development until there is spare capacity at the latter one, leaving Polarled underutilised.

Another important aspect of the tariff cut is its long-term implications on investment behaviour in the sector. The focus variable in the presented model is the share of recoverable investment costs. The reasoning behind this parameter is the existence of a second-hand market for the pipeline investments. Figure 4.1 shows how the Gassled ownership structure has changed since 2010, when preferential rights were abolished and financial companies (infrastructure, private equity and pension funds) acquired a large share of Gassled.



*Figure 4.1 Gassled composition in 2011 and 2016 (Data source: Gassco)*

\*Petoro serves as the licensee for the Norwegian state's direct financial interest (SDFI) in petroleum activities

The interest on such acquisitions by the investment funds suggests that Gassled shares had been generally considered secure and stably profitable investments before the tariff cut, although the financial companies accepted some volume risk. Although the tariff cut relates only to the existing facilities, potential investors have already announced their unwillingness to acquire the investments in the Polarled project. The reason behind such a decision is the increased regulatory risk. An important question is whether the current system provides sufficient perspectives for investment cost recovery, even with the high rate of return on new projects. At the moment, the existence of a market for infrastructure investments is under question. If the secondary market will not be recovered, there will be no demand for infrastructure investments, or gas companies will have to sell them at a lower price in order to recover some of the capital. If this price is too low for a company, it may prefer to keep the investments; then, the share of gas producers in Gassled will increase in the long run.

However, for the gas companies, investments in any excess capacity means tying-up the capital. The secondary market for infrastructure investments helped to resolve the problem of establishing excess capacity. For a financial company, the value of infrastructure investment consists of two elements: the value of income from initially committed volumes and the option value of excess capacity that may be used by third parties in the future. Therefore, investments in excess capacity could be reasonable for the financial companies. The recent tariff cut increased the regulatory risk, disturbing the secondary market. Even if the government sets up a reasonably high fixed part of the capital element of the tariff for new infrastructure projects, the increased regulatory risk would diminish the option value of excess capacity for the investor, making investments in excess capacity highly problematic.

The incentive problem may be resolved by greater participation of the state in the investment projects, for example through Petoro, by funding the excess capacity to incentivise companies to explore and develop the marginal fields along the pipeline. However, according to the existing framework, Petoro participates in infrastructure investments proportional to its shares in the corresponding gas fields. If the framework conditions for Petoro were changed, and Petoro covered the necessary part of the investment costs in order to develop socially optimal transport capacity, Petoro's share in Gassled would increase, making the system inclined to become state-owned. Such a solution may completely change the existing structure of investment incentives, and a deep study of its implications to the gas sector in Norway would be required.

## 5 Conclusion

This paper uses a game theoretic approach to understand the interplay between the existing tariff regime and investment behaviour in the Norwegian gas transport sector. The discussion about infrastructure development in the Barents Sea is the motivation for the paper and serves as an empirical base for modelling the choices of the parties involved in the process. Specifically, the trade-off between the pipeline infrastructure and the LNG infrastructure is analysed. The pipeline investments are characterised by significant economies of scale, which enable over-dimensioning of the pipelines with regard to future tie-ins. Availability of spare transport capacity in the pipeline motivates exploration and field developments, and may increase value creation in the gas sector in the long run. This makes pipeline investments with excess capacity a desirable alternative from a socio-economic point of view. On the other hand, the low initial investments and the destination flexibility with the corresponding price premium make LNG investments a preferred alternative for a gas company.

It was found that the final investment decision depends on the perspectives for investment costs recovery as provided by the tariff regime and on the decisions of the system operator, who plays a special role as the common agent in the infrastructure development problem. The government aims at welfare maximisation from all petroleum activities on the NCS. This objective has two dimensions: maximising the utilisation of the existing network and developing a new infrastructure. The tariff regime works in opposite directions for these two dimensions. This ambiguity reduces the ability of the tariff regime to provide sufficient investment incentives. The actions of the system operator can mitigate the conflict of interest between the long-term welfare maximising objectives of the government and the short-term profit maximisation of commercial companies. Observing the actions of the government and the incentives of the gas company as a common agent, the system operator suggests a solution that is feasible for both principals. Intervention of the system operator is necessary to coordinate the infrastructure planning process and ensure a well-functioning gas sector in the long run.

The model contains a set of rather strong simplifications (regarding the actions and payoffs of the players, relationships between the costs of the pipeline and LNG facilities, etc.) and does not pretend to be an exhaustive explanation of the complicated interactions within the gas transport market, but nevertheless, outlines its main features and provides an analytical structure to address important regulatory issues.

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**Paper 4**

**The environmental footprint of gas transportation: LNG vs.  
pipeline**

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# The environmental footprint of gas transportation: LNG vs. pipeline

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## Abstract

Emissions to air from production and transportation of natural gas is an important aspect of the decision making regarding the new infrastructure development in the offshore gas sector. In this study, we estimate the emissions of CO<sub>2</sub>, NO<sub>x</sub>, nmVOC and CH<sub>4</sub> from extraction, processing and transportation of a unit of dry gas from the continental shelf of Norway to consumer markets; and compare the resulting emission intensities of the pipeline value chains, where gas is transported in gaseous form, with the LNG (liquefied natural gas) chains, where gas is liquefied and shipped by LNG carriers. The analysis substantiates the environmental superiority of pipeline chains over LNG-based chains. However, the comparative analysis of ten pipeline chains highlights the variability of the environmental performance of different chain configurations. CO<sub>2</sub> emissions vary from 2.4 kg/Sm<sup>3</sup>o.e. to 352.4 kg/Sm<sup>3</sup>o.e. Due to the technological specificity of LNG chains, these prove to be significantly more CH<sub>4</sub>- and nmVOC-intensive than pipeline chains. With regard to NO<sub>x</sub> emissions, there is no clear advantage of the considered pipeline chains over LNG chains. The isolated analysis of the transportation segment of the value chains confirms the superiority of the pipeline transportation over the LNG.

**Keywords:** *Natural gas; Emissions to air; Pipeline transportation; LNG*

# 1 Introduction

The share of natural gas in the energy mix of the EU-28 has steadily increased from 17.8% in 1990 to 24.4% in 2010. In recent years, however, this share has declined slightly, down to 21.4% in 2014, due to low coal and carbon prices (Eurostat, 2016). Nevertheless, in EU Reference Scenario, the share of natural gas is relatively stable at the level of 24-26% in 2030-2050 (European Commission, 2016). Natural gas can play an important role in Europe's 'green transition' due to the fact that the combustion of a unit of natural gas generates about one-half of the CO<sub>2</sub> emissions of the equivalent amount of coal (53.07 kg of CO<sub>2</sub> per MBtu against 95.35 kg of CO<sub>2</sub> per MBtu (Energy Information Administration, 2016)). End-use combustion generates the majority (80–90%) of the CO<sub>2</sub> emissions from the natural gas value chain and has received due attention in academic research and political discussion. In this paper, however, we focus on the environmental footprint of the rest of the value chain: extraction, processing and transportation, which is especially important for gas-producing countries and their gas infrastructure development decisions. Relative advantage in terms of emissions to air in the upstream part of the natural gas value chain might become very important in the competition between the gas producers, especially under increasing CO<sub>2</sub> prices.

Emission intensity estimates of the upstream parts of the gas value chain can be found in studies devoted to life-cycle assessments of different fuels used for power generation in different parts of the world. For example, Tamura et al. (2001) and Okamura et al. (2007) perform analyses of the life-cycle CO<sub>2</sub> and CH<sub>4</sub> emissions from LNG and city gas in Japan. Jaramillo et al. (2007) present life-cycle air emissions of coal, LNG, synthetic natural gas and domestic gas for electricity generation in the US. Air emission estimates from gas production and transportation can also be found in life-cycle studies of transportation fuels. For instance, Arteconi et al. (2010) present a life-cycle GHG analysis of LNG as a heavy vehicle fuel and compared it to diesel in the context of European markets. COWI Consortium (2015) presents a study on actual GHG data on diesel, petrol, kerosene and natural gas through a life-cycle 'well-to-tank' approach.

There is also growing literature on the environmental effects relating to liquefied natural gas (LNG) chains. For example, the Pembina Institute (2013) presents a study of greenhouse gas emissions of the domestic component of the LNG chain in British Columbia. Abrahams et al. (2015) analyse how incremental US liquefied natural gas exports affect global greenhouse gas emissions. Several studies have considered both LNG and pipeline gas. ARI and ICF (2008) compares the emission intensities of CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O (from extraction to the burner tip) for the two main natural gas supply chains in the US: domestically produced gas and imported LNG. Starting from production up to consumption for power generation, Taglia and Rossi (2011) analyse the environmental and economic impacts of the gas entering Europe.

However, to our knowledge, there are no in-depth studies comparing the environmental footprint of LNG and pipeline chains from the perspective of a gas producer. In this paper, we have developed and applied an approach for a detailed analysis of emissions from the upstream part of the gas value chain based on real world data from the existing chains delivering gas from the Norwegian continental shelf to consumer markets.

Norwegian gas covers more than 20% of the EU's total gas consumption (Eurostat, 2016). Most of the Norwegian gas is transported via an extensive pipeline system across the North Sea to receiving terminals in Belgium, Germany, France and the United Kingdom. A small fraction of the gas (about 5% of total export) is shipped in liquid form by ocean-going tankers from the Hammerfest LNG (liquefied natural gas) facility in northern Norway to Europe, Asia and North and South America (Norwegian Petroleum Directorate, 2016). Norwegian

exploration activities move further north into the Norwegian Sea and the Barents Sea. This raises the question of a new transport infrastructure development for the purpose of evacuating gas from new fields to the markets. According to a recent study by the transport system operator, a pipeline chain and an LNG chain are both relevant solutions (Gassco, 2014). Besides having different socio-economic characteristics, these two alternatives may have considerably different environmental impacts. The choice between LNG-based chains and pipeline systems is also slated as a relevant consideration in other parts of the world (e.g. the UK, Canada and the USA).

Gavenas et al. (2015) empirically investigate the influence of the age and size of fields, the share of oil in total reserves, and the carbon prices on the CO<sub>2</sub> emission intensities of Norwegian oil and gas extraction. In this paper, we expand the scope of the analysis and, in addition to the extraction, we also consider the processing and transportation segments of the value chain. In order to compare the environmental footprint of the two main alternative gas chains, pipeline and LNG, we estimate the unit emissions to air of CO<sub>2</sub> (carbon dioxide), NO<sub>x</sub> (nitrogen oxides), nmVOCs (non-methane volatile organic compounds) and CH<sub>4</sub> (methane) associated with the extraction, processing and transportation of natural gas from the production fields on the NCS to consuming markets in gaseous form via pipelines and in liquid form by sea-going LNG carriers.

The paper is organised as follows. The methodology and the choice of cases are discussed in Section 2. Section 3 presents the results of the analysis. Subsection 3.1 is devoted to carbon emissions. Subsection 3.2 presents the analysis of other emissions. Subsection 3.3 outlines the analysis of indirect emissions related to the construction and decommissioning of infrastructure facilities. The results are discussed in Section 4, and Section 5 concludes.

## 2 Methodology

The natural gas value chain consists of five main parts for both LNG and pipeline gas: extraction, upstream transportation, processing, export transportation and distribution (Figure 2.1). The gas extracted at an offshore field is first transported via a pipeline to a processing facility. After processing, it can either be transported further via a pipeline or be liquefied, shipped by sea in special LNG tankers and regasified before being transmitted to downstream distributors.

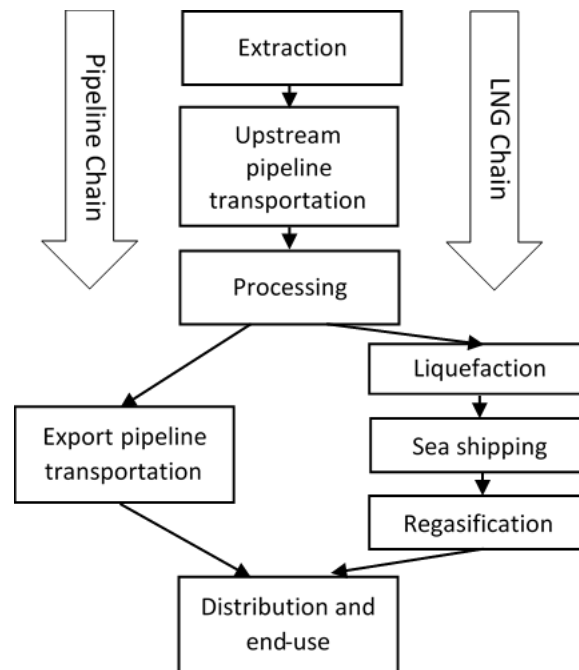


Figure 2.1 Natural gas value chain

The general structure of a pipeline chain may have several configurations. In a typical pipeline chain on the NCS, the water, condensate and parts of the NGL (natural gas liquids) are separated from the wellstream at offshore platforms, which is called the primary separation. The remaining raw (rich) gas is transported via rich gas pipelines to onshore facilities for further processing. When the remaining NGL are removed at a processing plant, dry gas (methane and some ethane) is transported via dry gas pipelines to Europe. On a receiving terminal, possible liquid residues and solid particles are removed, gas passes through a final quality check and regulation of pressure and temperature before delivery to downstream distributors. In some cases, the upstream transportation (rich gas pipelines) can be longer than the export transportation (dry gas pipelines). Some fields situated close to the shore have no processing steps offshore. The unprocessed wellstream is sent directly via multiphase pipelines to a processing facility onshore. There are also fields that are not connected to any onshore processing facility. The wellstream is processed at a platform, and the resulting dry gas is sent directly to continental Europe via dry gas pipelines. The choice of a processing solution depends on many factors such as the location of the reservoir, sea depth, distance to shore and available transportation solutions.

In order to perform a reasonable comparison, we consider ten pipeline chains (Figure 2.2, Table 2.1), which represent the described configurations. We consider fields of different size and age connected to each of the three major gas processing plants on the NCS: Kårstø in Rogaland, Kollsnes in Hordaland and Nyhamna in Møre og Romsdal County and two fields with offshore processing. A significant difference between environmental footprints also comes from the power generation options available to each facility. Therefore, we include in the analysis fields connected to the main electricity grid onshore and the fields using feed gas to generate electricity.

The environmental footprint of gas transportation: LNG vs. pipeline

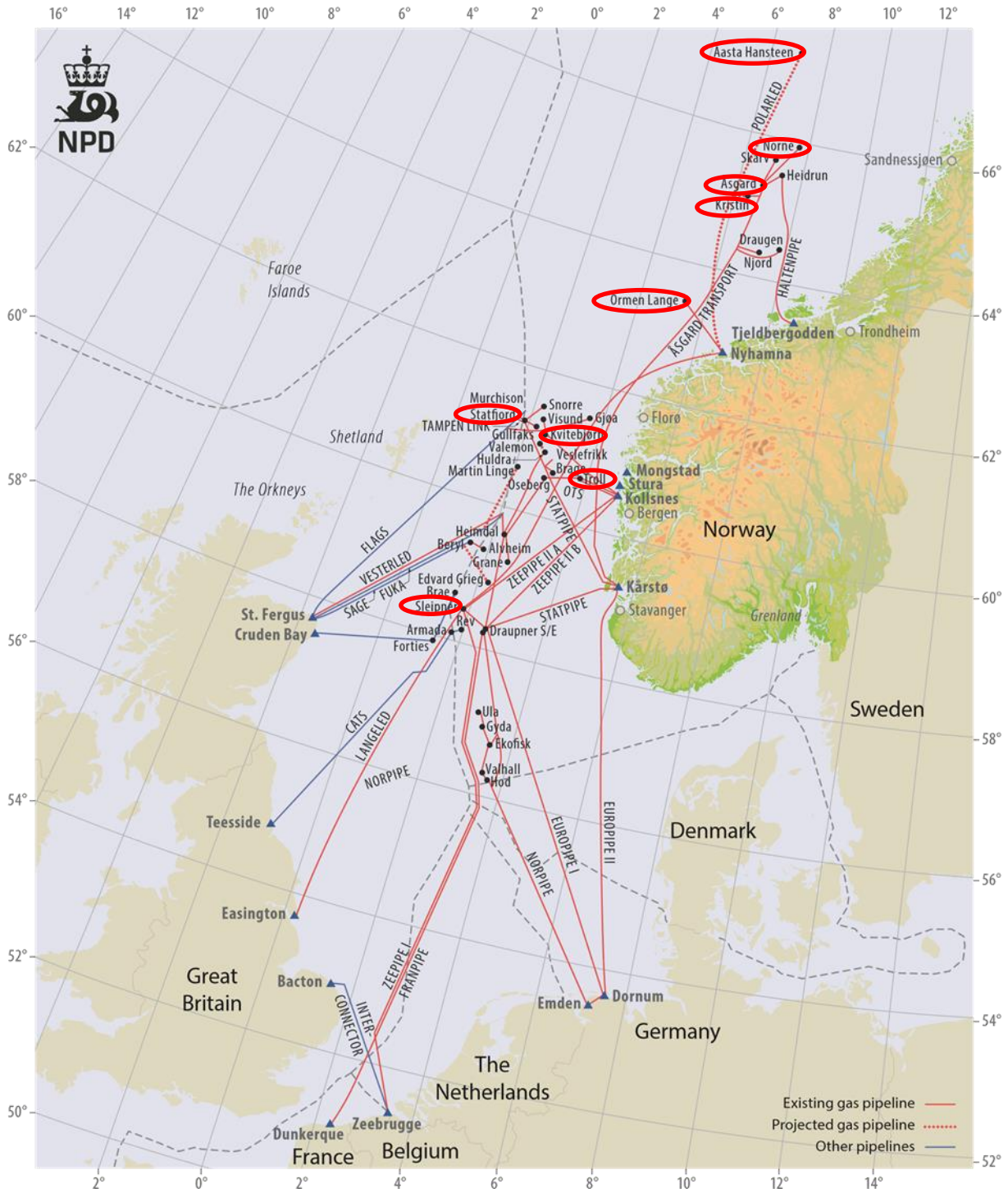


Figure 2.2 Gas pipelines on the NCS (Source: The Norwegian Petroleum Directorate). The circles highlight the fields chosen for the analysis

There is only one large-scale LNG chain on the NCS, which produces gas from the Snøhvit field in the Barents Sea (not illustrated in Figure 2.2; it is situated 70° latitude.). As the estimates are sensitive to the distance over which the LNG is shipped, we consider three alternative destinations: the two existing shipping routes to the Iberdrola terminal in Spain, Bilbao, and the Cove Point terminal on the Western coast of the US as well as one hypothetical destination, the Zeebrugge terminal in Belgium, which represents a close comparison to a pipeline alternative.



A brief description of the chains and the corresponding net production of sale gas, oil, NGL and condensate is presented in Table 2.1. Most of the considered offshore platforms receive and process the wellstream from several satellite fields. The numbers presented include these volumes. It should also be noted that while Table 2.1 indicates the main flows of sales gas, via a system of hubs gas from one field can be directed to several alternative destinations in Europe.

The total emission intensities of pipeline and LNG chains are estimated by adding up emission intensities on all segments of the defined parts of the chains. The emissions relating to extraction include those by mobile units used to drill production wells. Exploration (seismic surveys by special ships, exploration drilling by drilling rigs) and support activities provided by supply vessels and helicopters and emissions relating to the storage and loading of oil and NGL/condensate are excluded from the analysis.

The analysis of the extraction-related emissions is based on the yearly reports of the operators of the platforms on the NCS to the Ministry of Climate and Environment (mainly 2014, and in some cases, 2013 and 2012). These environmental reports provide data on total annual emissions from flares, turbines, boilers, ovens, engines, cold vents and fugitive emissions from the offshore platforms. We calculated the emission intensities by combining the information on the reported emissions and the volumes of produced, processed or transported hydrocarbons – a top-down approach.

Onshore facilities report only some emissions relating to certain processes. The missing data was obtained from other sources: plans for the development and operation of petroleum deposits; plans for the installation and operation of facilities and other publicly available technical documentation.

Table 2.1 Description of the pipeline and LNG chains

<b>Field, year of prod. Start (Satellites)</b>	<b>Upstream gas transport</b>	<b>Processing facility</b>	<b>Export gas transport, destination point</b>	<b>Gas, Sm<sup>3</sup> o.e./year</b>	<b>Oil, Sm<sup>3</sup> o.e./year</b>	<b>Condensate/ NGL Sm<sup>3</sup> o.e./year</b>
Åsgard, 1999 (Mikkel, Morvin)	Åsgard Transport (707 km, 42")			11 836 432	4 254 851	4 699 456
Kristin, 2005 (Tyrihans)	Åsgard Transport (707 km, 42")		Europipe II (658 km, 42") to Dornum, Germany	2 525 856	4 402 247	979 629
Norne, 1997, gas export from 2001	Norne Gas Transport (128 km, 16"), Åsgard Transport (707 km, 42")	Kårstø		2 074 794	2 535 672	486 694
Statfjord, 1979 (Statfjord Nord, Statfjord Øst, Sygna, Snorre and Vigdis)	Statpipe (308 km, 30")		Statpipe (228 km, 28") – Draupner S – Statpipe (203 km, 36") – Norpipe (440 km, 36"), to Emden, Germany	1 859 285	7 550 282	1 645 631
Troll, 1995 (Fram, Fram-H Nord)	Field-dedicated multiphase pipeline (63 km)		Zeepipe IIA (303 km, 30") – Sleipner R – Zeepipe (814 km, 40"), to Zeebrugge, Belgium	29 651 627	9 850 985	1 323 609
Kvitebjørn, 2004	Kvitebjørn Pipeline (147 km, 30")	Kollsnes	Zeepipe IIB (304 km, 30") – Draupner E – Europipe (620 km, 40"), to Dornum, Germany	6 768 726	1 981 585	979 431
Ormen Lange, 2007	Field-dedicated multiphase pipeline (120 km)		Langeled North (627 km, 42") – Sleipner R – Langeled South (543 km, 44"), to Easington, UK	20 209 660	0	1 363 755
Aasta Hansteen, 2017	Polarled (481 km, 36")	Nyhamna		7 700 000	0	175 000
Sleipner Øst, 1993 (Gudrun, Gungne, Sigyn, Volve)	Offshore		Zeepipe (814 km, 40"), to Zeebrugge, Belgium	5 821 793	1 940 187	550 080
Sleipner Vest, 1996	Offshore			4 766 108	0	2 221 946
Snøhvit, 2007	Field-dedicated multiphase pipeline (143 km)	Hammerfest LNG	- Cove Point, US (4072 nautical miles) - Iberdrola, Spain (2019 nautical miles) - Zeebrugge, Belgium (1375 nautical miles)	4 651 352	0	1 200 359

Source: own compilation based on annual reports of field operators to the Norwegian Ministry of Climate and Environment

The total emissions of a facility needed to be allocated between the hydrocarbon products produced at that facility (gas, oil, condensate, NGL) on the basis of their contributions to the total emissions. For example, gas turbines, the main emitters of CO<sub>2</sub> and NO<sub>x</sub> offshore, produce energy for all the operations on a platform, including the extraction, processing and compression of gas for pipeline transportation. Most of the existing literature (e.g. Tamura 2001; Okamura, 2007) considers the NGL and condensate on par with dry gas, assuming that their emission intensity is the same. However, these studies do not consider fields that produce oil in addition to gas and condensate. Gavenas et al. (2015), estimating the CO<sub>2</sub> emission intensity of oil and gas extraction on the NCS, assumed that all products had the same impacts. We allocate the emissions between the hydrocarbon flows based on the following considerations: emissions generated by gas flaring, boilers and engines are attributed to the production/processing of the wellstream and are therefore related equally to gas, oil, condensate and NGL. A part of the emissions generated by gas turbines relates to the energy needs of the compressors used to inject gas or seawater to maintain pressure in reservoirs and for the living quarters on manned platforms. This part of the emissions is also allocated equally between all four products. A second part of the energy produced is used to compress gas for pipeline transportation. There is very limited information on the relative share of the energy used for gas transportation in the total energy production on a platform. Only one report (for the Norne field) provides precise information: 65% of the energy generated is used for export compression. Some information can be extracted from industry analytics and appraisal reports. In Bakkan (1994), 59% of gas turbine emissions are attributed to production and 41% to transportation. In the impact assessment of the Linnorm field development (Shell, 2012), 82% of all CO<sub>2</sub> emissions from the field were attributed to export compression; however, this field does not contain a considerable amount of oil. When more detailed data is not available, we assume that 60% of the power generated by turbines is consumed by the compressors used to transport gas and that 40% is used for other field operations.

The unit emissions of CO<sub>2</sub> and NO<sub>x</sub> from an offshore platform relating to gas extraction, initial processing and compression,  $UE^{Gas}$ , are calculated on the basis of the following logic:

$$UE^{Gas} = \frac{TE^{flares} + TE^{boilers} + TE^{ovens} + TE^{well\ tests} + r * TE^{turbines}}{\sum_{i=1}^n (V_i^{Gas} + V_i^{Oil} + V_i^{NGL} + V_i^{condensate})} + \frac{(1 - r)TE^{turbines}}{\sum_{i=1}^n V_i^{Gas}},$$

where  $TE^{flares}$ ,  $TE^{boilers}$ ,  $TE^{ovens}$ ,  $TE^{well\ tests}$  and  $TE^{turbines}$  are the total reported emissions of the considered type (CO<sub>2</sub> or NO<sub>x</sub>) from flares, boilers, ovens, well tests and turbines, respectively, on the platform;  $V_i^{Gas}$ ,  $V_i^{Oil}$ ,  $V_i^{NGL}$  and  $V_i^{condensate}$  are the volumes of the corresponding hydrocarbons produced at a field  $i$  which is connected to the platform;  $0 \leq r \leq 1$  is the part of the energy used for processes other than gas export compression. The volume of hydrocarbons is measured in Sm<sup>3</sup>o.e. (corresponds to 1000 Sm<sup>3</sup> of gas, 1 Sm<sup>3</sup> of oil, 1 Sm<sup>3</sup> of condensate and 1 Sm<sup>3</sup> of NGL). In order to calculate unit emissions of CH<sub>4</sub> and nmVOC, the first part of the formula also includes diffuse emissions and cold vents.

The fact that the analysis is based on environmental reports for each platform gives this study the advantage of using field-specific emission factors and values measured at site instead of theoretical parameters. Theoretical emissions factors are used to estimate emissions relating to LNG sea shipping and regasification.

Studies focusing on greenhouse gas emissions in the gas sector usually point to the CO<sub>2</sub> content in raw gas. If it is higher than what is specified in sales agreements (2.5 mol% for the pipeline gas entering the EU), the excess CO<sub>2</sub> should be separated and is either vented to the air, which is usual, or in some cases sequestered in underground storage. The organisation of the pipeline network on the NCS allows blending gas from most of the fields in order to achieve

the required sales specification without having to separate and vent CO<sub>2</sub>. The exact data on the proportions in which the gas from different fields is blended is not accessible; therefore, we do not consider this aspect separately. There is a CO<sub>2</sub> removal facility at the Kårstø plant, from where the separated CO<sub>2</sub> is vented to the air. The relevant emissions are included in the emission intensity of the processing at this plant.

We assume a zero emission factor for grid electricity. Electricity in Norway is almost entirely generated by renewables (in 2014, 95.9% was hydropower). According to the International Energy Agency (2011), CO<sub>2</sub> emissions from the electricity sector in Norway are about 5 grams per kWh, which is negligible compared to the OECD average of 443 grams per kWh.

### 3 Results

#### 3.1 Carbon emissions

Figure 3.1 shows the CO<sub>2</sub> emission intensities of the considered chains. The footprint of the pipeline chains varies from 2.4 kg/Sm<sup>3</sup>o.e. for the Ormen Lange chain to 352.4 kg/Sm<sup>3</sup>o.e. for the Statfjord chain. However, the Statfjord field is an outlier with 300.435 kg/Sm<sup>3</sup>o.e. of offshore emissions. It is one of the oldest fields on the NCS, on its late life production stage, with much lower energy efficiency compared to newer fields.<sup>1</sup>

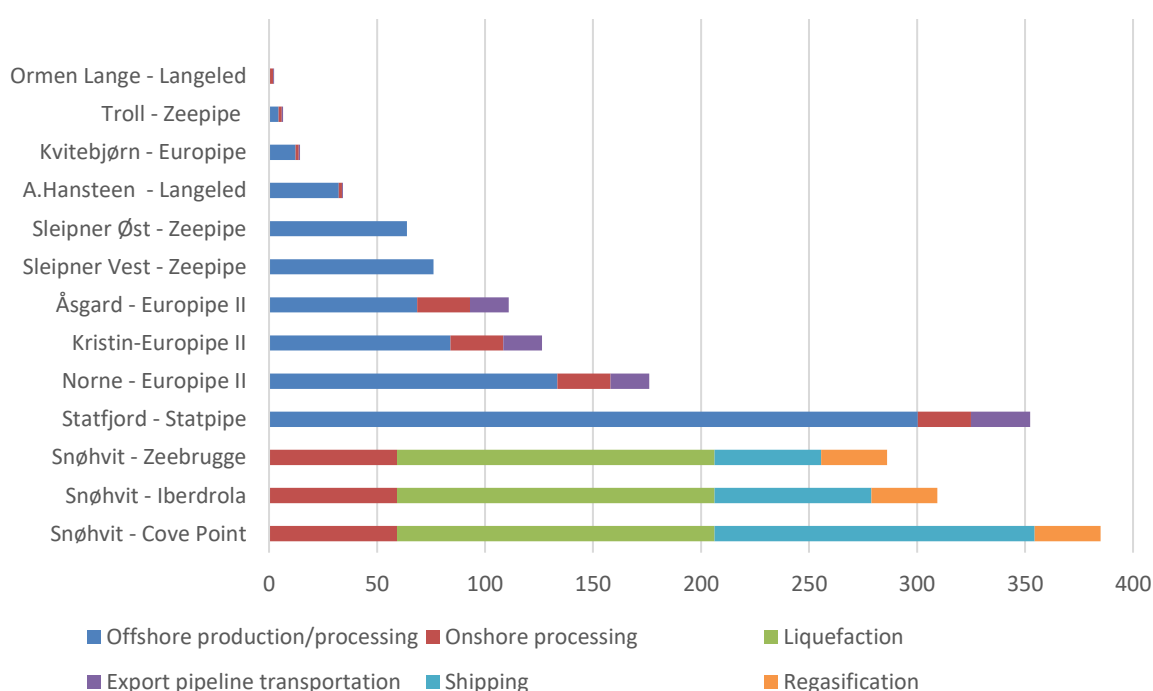


Figure 3.1 CO<sub>2</sub> emission intensity (kg/Sm<sup>3</sup>o.e.)

<sup>1</sup> The Statfjord infrastructure complex is undergoing significant reconstruction and will become more energy efficient in the near future.

The largest contributor to the CO<sub>2</sub> footprint of the pipeline chains is the offshore segment, which is due to gas-based energy production. Turbines account for about 90% of the total emissions of the fields not connected to the main electricity grid onshore (e.g. 90.2% for Norne and 90.18% for Kristin in 2014).

The footprint of the Snøhvit LNG chain varies from 286.2 kg/Sm<sup>3</sup>o.e. for the shortest route to 385.0 kg/Sm<sup>3</sup>o.e. for the longest route. The main emissions contributors are power generation for liquefaction and fuel combustion for sea shipping.

The lowest CO<sub>2</sub> intensity is inherent to the chains connected to the main electricity grid onshore, Ormen Lange and Troll, where gas is not used for power generation in any segment of the value chain. The gas from the Ormen Lange field is extracted by a subsea installation, which receives power from the land and produces no emissions to air except exhaust gases during the drilling of the production wells (0.430 kg/Sm<sup>3</sup>o.e.). The unprocessed wellstream is transported to the Nyhamna plant, which uses grid electricity for all processes, including export compression. Processing-related emissions are mainly from flares and diesel engines (1.421 kg/Sm<sup>3</sup>o.e.). The infrastructure complex Troll consists of three platforms: Troll A, B and C. The gas is produced at the Troll A platform while oil is mainly produced at Troll B and C. Troll A receives power from the main grid onshore and does not utilise gas turbines for power generation. The emissions from the platform are from flares and engines (4.357 kg/Sm<sup>3</sup>o.e.). The Kollsnes processing plant also uses grid electricity for export compression, adding only 1.602 kg/Sm<sup>3</sup>o.e. to the total chain emissions. The export transportation segment for these two chains adds only 0.551 kg/Sm<sup>3</sup>o.e., which is emitted by gas turbines to produce energy at riser platforms for the monitoring of the pressure, volume and quality of the gas flows at the hubs.

These two chains have a very low emission footprint because they are situated close to the shore, and it was technically possible and economically reasonable to connect them to the electricity grid onshore. Another gas field connected to the Kollsnes plant is Kvitebjørn, which uses gas power at the platform, produces 12.203 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. of gas. The total unit CO<sub>2</sub> emissions for these chains are 2.2 times higher than that of the Troll chain. In 2017, the Aasta Hansteen field is expected to come on stream, connected to the Nyhamna plant. The development concept is a floating platform, which covers energy needs by a gas power plant on site. Rich gas will be transported to Nyhamna via the 480 km Polarled pipeline. The offshore segment of this chain will emit 32.266 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. of gas.<sup>2</sup>

The pipeline chains connected to the Kårstø processing plant have the highest CO<sub>2</sub> emission intensities. The explanation is twofold: these chains have high offshore emissions because of the long upstream transportation segment; there are also high emissions at the onshore segment. The processing-related emissions at this plant (24.542 kg/Sm<sup>3</sup>o.e.) are as high in comparison to the other two plants due to the CO<sub>2</sub> removal from the raw gas, which is vented to air. The export compression is also mostly gas driven. The plant receives gas from two incoming rich gas pipelines, Statpipe, which brings gas from the Statfjord field, and Åsgard Transport, which brings gas from the Norne, Kristin and Åsgard fields. After processing, the Statpipe gas is exported via the Statpipe dry gas pipeline, and the Åsgard gas is exported via Europipe II. The export transportation via Europipe II is slightly less emission-intensive (17.916 kg/Sm<sup>3</sup>o.e.) than via Statpipe (26.873 kg/Sm<sup>3</sup>o.e.) because one of the three compressors at the entry of this pipeline is driven by an electrical compressor while all three are gas-driven at

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<sup>2</sup> The data for the expected emissions of CO<sub>2</sub>, NO<sub>x</sub> and nmVOC are taken from the plan for the development and operation of the field delivered to the Ministry of Petroleum and Energy in 2012 (Statoil, 2012). The CH<sub>4</sub> emissions estimate is based on experience data from similar fields.

the Statpipe entry. The Statpipe transportation line also includes a hub, which generates an additional 0.551 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. of gas transported.

The Kristin chain was included in the analysis to determine whether there is a scale effect of the volume of gas produced at a field in relation to the CO<sub>2</sub> footprint. The emission intensity of the offshore operations at Kristin is 83.975 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e., which is 22.51% higher than that of the Åsgard field (68.532 kg/Sm<sup>3</sup>o.e.), which produces about four times more gas. The Norne chain is the longest pipeline chain operating on the NCS (1493 km from the field to the receiving terminal in Germany). The Norne field (of a size comparable to Kristin) is connected to Åsgard Transport via an additional 128 km pipeline. The emission intensity of the offshore segment of the Norne chain is 133.529 kg/Sm<sup>3</sup>o.e., which is 59.01% higher than that of Kristin.

After the four chains, which use grid electricity, the next highest emission intensity comes from the two fields, Sleipner Øst and Sleipner Vest, which have no processing steps onshore.<sup>3</sup> However, this result should be seen in light of the distances over which the gas is transported: the distance is about twice shorter for the Sleipner gas than for the Åsgard gas. The emission intensity of Sleipner Øst<sup>4</sup> (63.837 kg/Sm<sup>3</sup>o.e.) is lower than that of Sleipner Vest (76.138 kg/Sm<sup>3</sup>o.e.) because of the difference in processing the wellstream. The Sleipner Vest gas has a high CO<sub>2</sub> content, up to 9 mol%, while Sleipner Øst only has about 1 mol%. The development concept for Sleipner Vest included the first commercial offshore carbon treatment and storage project in the world. The separated excess CO<sub>2</sub> is injected in a subsea reservoir for storage. The treatment and injection of the separated CO<sub>2</sub> adds about 13 kg of CO<sub>2</sub> to the emission intensity of the chain.

According to Figure 3.1, the LNG chains are considerably more CO<sub>2</sub> intensive than the considered pipeline chains, except for the Statfjord chain. However, the Melkøya LNG plant is considered the cleanest in the world (e.g. Glave and Moorhouse, 2013). There are two main reasons for this. The CO<sub>2</sub> content of the gas from the Snøhvit area is rather high, about 5–8 mol%, but the separated CO<sub>2</sub> is transported through a pipeline back to the field and injected in the underground reservoirs. This offsets most of the emissions that would otherwise be vented to air (according to our estimates, that would mean an additional 150.494 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e.). The cold climate of northern Norway also benefits the plant, making the process more thermally efficient.

The unprocessed wellstream from the Snøhvit field is extracted by a subsea gathering system and transported via a 143 km pipeline to the onshore processing and liquefaction facility. The upstream transportation part of the LNG chain produces no emissions; the wellstream reaches the onshore facility due to reservoir pressure. All processing of the wellstream takes place at the Melkøya LNG plant. The emission intensity of the onshore segment of the chain is 206.243 kg/Sm<sup>3</sup>o.e.<sup>5</sup> The energy needs of the plant are covered by its own energy production from the use of five gas turbines. On the basis of the information provided in Neeraas and Maråk (2011),

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<sup>3</sup> Several processes at the two fields are interconnected; therefore, not all emissions can be accurately separated. The resulting emission intensity is slightly overestimated for Sleipner Øst and underestimated for Sleipner Vest.

<sup>4</sup> The estimate is based on data from 2013 because in 2014, a new field (Gudrun) was connected to the infrastructure complex. Apart from somewhat increased CO<sub>2</sub> and NO<sub>x</sub> emissions due to the installation and preparation of equipment on the Gudrun platform, the drilling of five new wells caused high nmVOC and CH<sub>4</sub> emissions, which resulted in untypical unit emissions for the Sleipner Øst system.

<sup>5</sup> The only available complete emission data for the plant is for 2012. The production volume and general emission level in 2012 were not significantly different from 2014.

we estimate that about 90% of the generated power is used for liquefaction, meaning that the largest part (146.975 kg/Sm<sup>3</sup>o.e.) of the total emissions is due to liquefaction. The resulting LNG is transported by conventional LNG tankers with a cargo capacity of 145,000 m<sup>3</sup> and a service speed of 19.5 knots. The tankers use the steam-turbine propulsion system whose main engines are 27,600 kW. The boil-off rate is assumed to be 0.15% of the daily cargo capacity and covers 50% of the fuel requirements; another 50% is HFO (heavy fuel oil). Using the emission factors for ship propulsion provided by Wayne (2006), the emission intensity of sea shipping is 148.251 kg/Sm<sup>3</sup>o.e. for the Cove Point destination, 72.672 kg/Sm<sup>3</sup>o.e. for Iberdrola and 49.417 kg/Sm<sup>3</sup>o.e. for Zeebrugge. For all three destination points, we assume that 1.5% of the gas received is used as fuel for the submerged combustion vaporisers for the regasification of the LNG (ARI and ICF, 2008). Using an expansion ratio of 577 m<sup>3</sup>(n)/ m<sup>3</sup>(liq) (International Gas Union, 2012) and the CO<sub>2</sub> emission factor provided by the American Petroleum Institute (2015),<sup>6</sup> the emission intensity of regasification is 30.536 kg/Sm<sup>3</sup>o.e.

### 3.2 Other emissions

NO<sub>x</sub> emissions mainly depend on the technologies used for power generation: low-NO<sub>x</sub> turbines significantly reduce the amount of NO<sub>x</sub> emitted into the atmosphere compared to conventional turbines. The strict requirements introduced by the Norwegian government have incentivised investment in low-NO<sub>x</sub> technologies in recent field developments. This explains the high NO<sub>x</sub> intensity of the Statfjord chain, which was developed long before these measures were introduced (Figure 3.2). The next highest NO<sub>x</sub> intensity is from the Sleipner Vest chain, which has no low-NO<sub>x</sub> turbines installed, the same as Sleipner Øst.

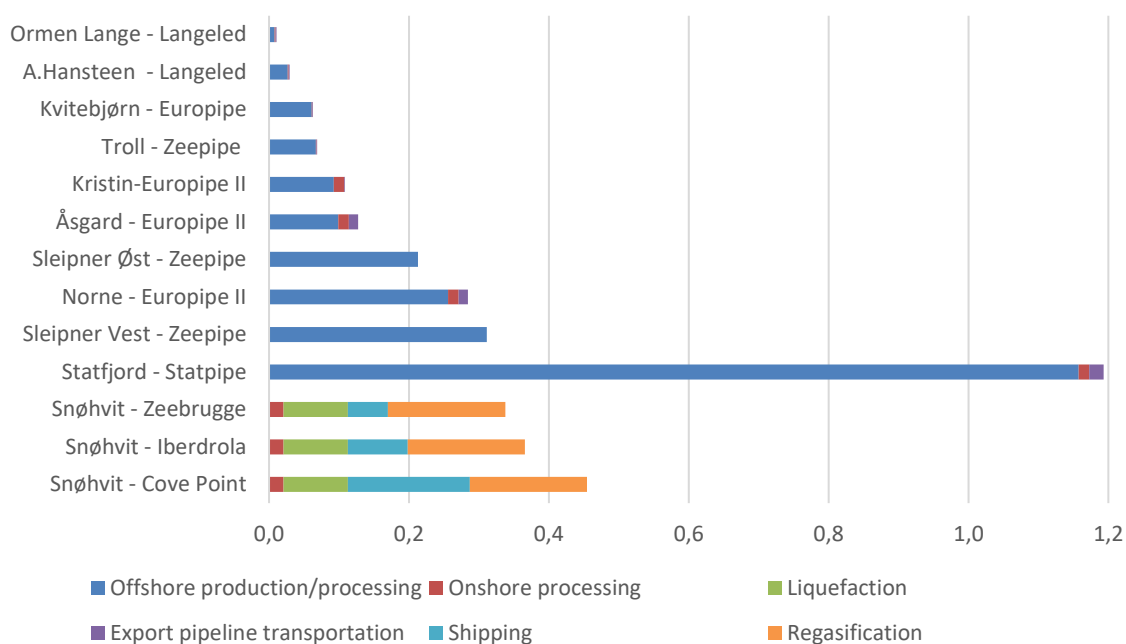


Figure 3.2 NO<sub>x</sub> emission intensity (kg/Sm<sup>3</sup>o.e.)

<sup>6</sup> For emissions of NO<sub>x</sub>, nmVOC and CH<sub>4</sub>, we used the Norwegian industry-specific emission factors.

The use of low-NO<sub>x</sub> technologies on the Hammerfest LNG facility made it possible to have a rather low NO<sub>x</sub> emission intensity for the onshore part of the LNG chain. Not taking into account the Statfjord chain as a clear outlier, the NO<sub>x</sub> intensity of the LNG chains is only marginally higher than that of several of the pipeline chains. It should also be noted that we assume that conventional turbines are used to generate power for regasification. If low-NO<sub>x</sub> technologies are also used for regasification, the NO<sub>x</sub>-intensity advantage of the pipeline chains over the LNG chains can be mitigated.

The advantage of the pipeline chains over LNG is unquestionable in terms of nmVOC and CH<sub>4</sub> emissions (Figure 3.3 and Figure 3.4). The main sources of these emissions are fugitive emissions and cold vents. Due to the specificity of the technology, leakage is more inherent to the LNG. It should be noted that the reported fugitive emissions from the fields are based on industry-specific factors, and the resulting estimates are characterised as highly uncertain. The reported fugitive emissions from the onshore facilities are based on onsite measurements.

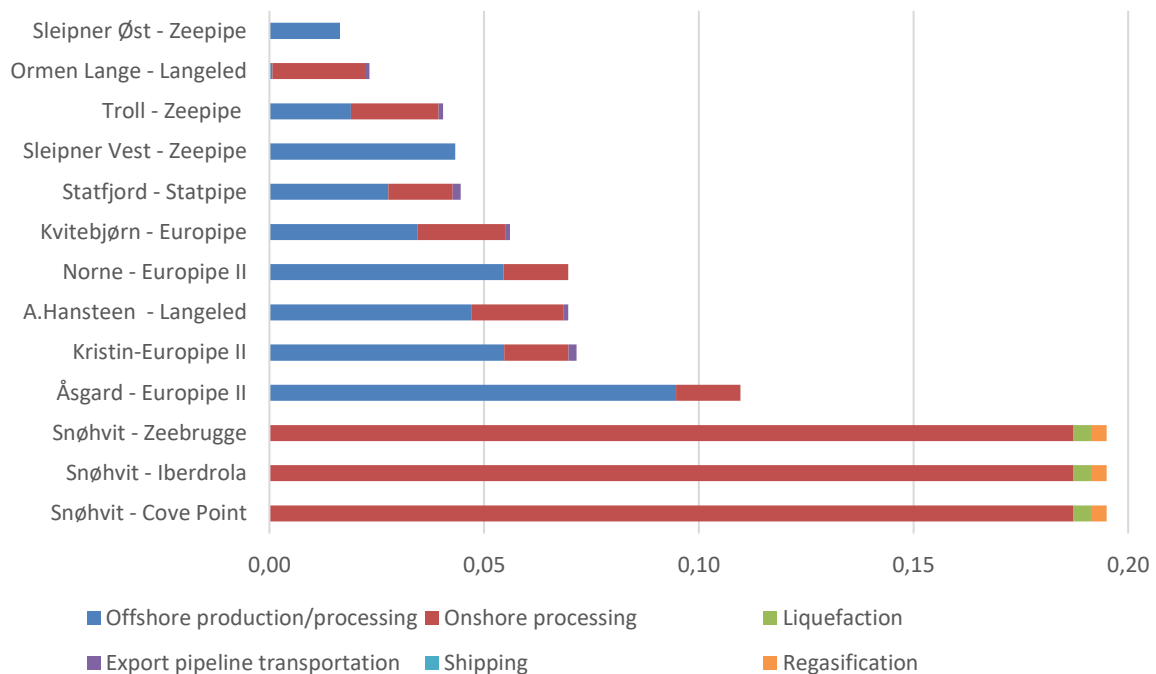


Figure 3.3 nmVOC emission intensity (kg/Sm<sup>3</sup>o.e.)



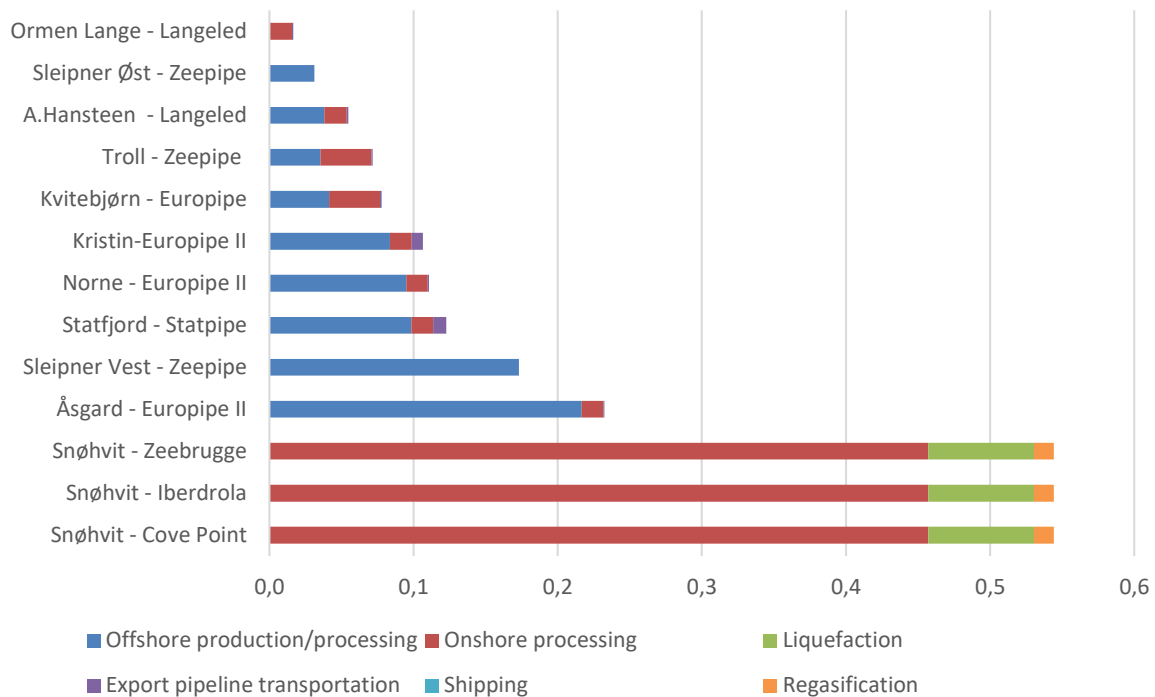


Figure 3.4 CH<sub>4</sub> emission intensity (kg/Sm<sup>3</sup>o.e.)

### 3.3 Indirect emissions related to the construction and decommissioning of facilities

The construction of offshore platforms, pipelines and processing plants requires substantial volumes of steel and concrete. The production of these materials is highly energy intensive and causes significant greenhouse gas emissions. We assume that the amount of materials required for the construction of platforms and processing facilities for pipeline and LNG chains are analogous and can therefore be ignored in this study. Our focus is on the transportation part of the chains: LNG carriers and pipelines. The steel from an old LNG carrier can be recycled, and therefore, the emissions to air caused by its production are limited. The decommissioned pipelines, according to Norwegian regulation, can be left at site as industrial waste and, hence, will not be recycled, thus representing a source of indirect emissions. We estimate the CO<sub>2</sub> emissions associated with pipeline production and installation based on the data provided in the plan for the development and installation of the Polarled pipeline (Statoil, 2012). The Polarled rich gas pipeline (481 km, capacity 70 MSm<sup>3</sup>/day) requires 325,000 tonnes of steel and 250,000 tonnes of concrete. The expected lifetime of the pipeline is 50 years. Assuming the following rather conservative utilisation scenario: 60% for the first 10 years, 80% for the next 40 years, we obtain 931 billion Sm<sup>3</sup> of gas transported during the lifetime of the pipeline. The installation and preparation of the pipeline for operation generates approximately 44,000 tonnes of CO<sub>2</sub>. According to the World Steel Association (2015), on average, 1.8 tonnes of CO<sub>2</sub> are emitted for every tonne of steel produced. The production of one tonne of concrete on average generates emissions of approximately 1.05 tonnes of CO<sub>2</sub> (National Ready Mixed Concrete Association, 2012).

By calculating the total CO<sub>2</sub> emissions, and weighing them by the total amount of gas transported during the Polarled pipeline's lifetime, we obtained 0.96 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. of gas transported. Taking into account the facts that pipelines can be in use longer than the

expected lifetime and that the utilisation rate may be higher than what we assume, the number obtained is the upper bound for the unit indirect emissions. We conclude that the indirect environmental effect of pipeline production and installation are marginal and do not significantly affect the results.

## 4 Discussion

The results of this comparative study corroborate the general findings of other studies that pipeline transportation chains environmentally outperform LNG-based chains, as LNG chains comprise extra processing steps (e.g. Kavalov et al., 2009). However, this empirical analysis highlights several other important aspects.

The most important observation is the variability of the environmental performance of different technological solutions and the corresponding emission intensities. This limits the usability of average estimates and restricts the scope for drawing general conclusions regarding pipeline transportation emission intensities. In cases where the fields are geographically close to the shore and electricity is available from the main grid (e.g. Ormen Lange and Troll), pipeline transportation is indeed 'green'. In other cases (e.g. Norne, Kristin and Åsgard), long distances and the need to generate power offshore make pipeline transportation significantly more emission-intensive. For pipeline chains where connection to the main electricity grid onshore is not technically possible or not economically reasonable, the largest contributor to the total CO<sub>2</sub> emissions is the combustion of natural gas in power-generating turbines. The comparison between the Kristin and Åsgard chains also indicates that the unit emissions of larger fields may be lower than that of smaller ones. Due to technological specificity, LNG chains are significantly more CH<sub>4</sub>- and nmVOC-intensive than pipeline chains. With regard to NO<sub>x</sub> emissions, there is no clear advantage of the considered pipelines over LNG chains.

In the above analysis, we focused on the environmental footprint of pipeline gas and LNG from production fields to the receiving terminals of consuming markets. However, extraction and processing segments of pipeline and LNG chains do not have major technological differences that would make the emission intensity of these two segments different for pipeline and LNG gas. Thus, it is interesting to consider the transportation segments separately. The existing literature (e.g. Taglia and Rossi, 2012) does not distinguish upstream transportation as a separate segment of the value chain; it is treated as a component of processing. We consider upstream transportation as part of a complete transportation solution for a field on the basis of the following considerations. An LNG solution assumes that a liquefaction facility is built geographically close to the field, meaning that the upstream transportation segment is in fact absent, as in the Snøhvit case, or is very short if a field were to be situated further from the shore, and compression would be required to deliver the gas onshore. As opposed to LNG, investments in pipeline gas infrastructure have very high economies of scale: there are low costs to establish overcapacity, both in the pipelines and in the processing facilities. In addition, higher-dimension pipelines are more energy efficient, incurring lower unit operating costs in comparison to low-dimension pipelines. Therefore, new fields are usually connected to existing plants with spare capacity, often with long upstream transportation segments, as in the Aasta Hansteen case.

Norne is the only pipeline chain for which the available data allows the precise separation of the emissions related to upstream gas transportation. Out of 133.529 kg of CO<sub>2</sub> emitted offshore per unit of gas, 103.059 kg is related to the power generation for gas transportation to the processing plant. An additional 17.916 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. is related to export transportation from the plant to Europe. In total, out of 175.986 kg of CO<sub>2</sub> emitted per a Sm<sup>3</sup>o.e.

of gas produced and transported from the Norne field to the receiving terminal in Germany, 120.975 kg of CO<sub>2</sub> is generated by pipeline transportation (upstream and export). These emissions can be compared to the emissions categorised as related to LNG transportation, that is, emissions from liquefaction, shipping and regasification. For the hypothetical Zeebrugge LNG chain, these emissions are 226.928 kg of CO<sub>2</sub> per Sm<sup>3</sup>o.e. of gas delivered.

Table 4.1 presents our estimates of the transportation-related emissions for the other chains. Pipeline transportation accounts for about 55–70% of the total CO<sub>2</sub> emissions of the chains that utilise gas-based power for transportation while LNG transportation accounts for about 80–85% of the total CO<sub>2</sub> emissions.

*Table 4.1 Emission intensity of gas transportation*

	<b>Value chain total, kg/Sm<sup>3</sup>o.e.</b>	<b>Upstream transportation, kg/Sm<sup>3</sup>o.e.</b>	<b>Export transportation, kg/Sm<sup>3</sup>o.e.</b>	<b>Share of transportation in total, %</b>
Ormen Lange - Langeled	2.40			
Troll - Zeepipe	6.51			
Kvitebjørn - Europipe	14.36	7.90		55.01
A.Hansteen - Langeled	34.24	23.38		68.28
Sleipner Øst	63.84		40.21	62.99
Sleipner Vest	76.14		41.68	54.75
Åsgard - Europipe II	110.99	44.76	17.92	56.47
Kristin - Europipe II	126.43	66.08	17.92	66.43
Norne - Europipe II	175.99	103.06	17.92	68.74
Statfjord - Statpipe	352.40	218.93	27.42	69.91
Snøhvit - Zeebrugge	286.20		226.93	79.29
Snøhvit - Iberdrola	309.45		250.18	80.85
Snøhvit - Cove Point	385.03		325.76	84.61

A direct comparison of pipeline and LNG transportation may not be reasonable in cases where LNG is transported over long distances where pipeline transportation is impossible. For infrastructure development decisions made by an exporting nation, however, it is of interest to focus on the domestic part of the transportation chain. For pipeline chains, all the emissions from upstream and export transportation are attributed to the domestic part of the value chain because compression takes place at pipeline entries. For LNG transportation, domestic emissions are only those from liquefaction. Figure 4.1 shows that the domestic part of the transportation-related emissions of the pipeline chains are lower than that of the LNG chains. However, domestic emissions of the transportation part of the longest pipeline chain, Norne, are only 17.69% lower than that of the domestic part of the LNG chains.

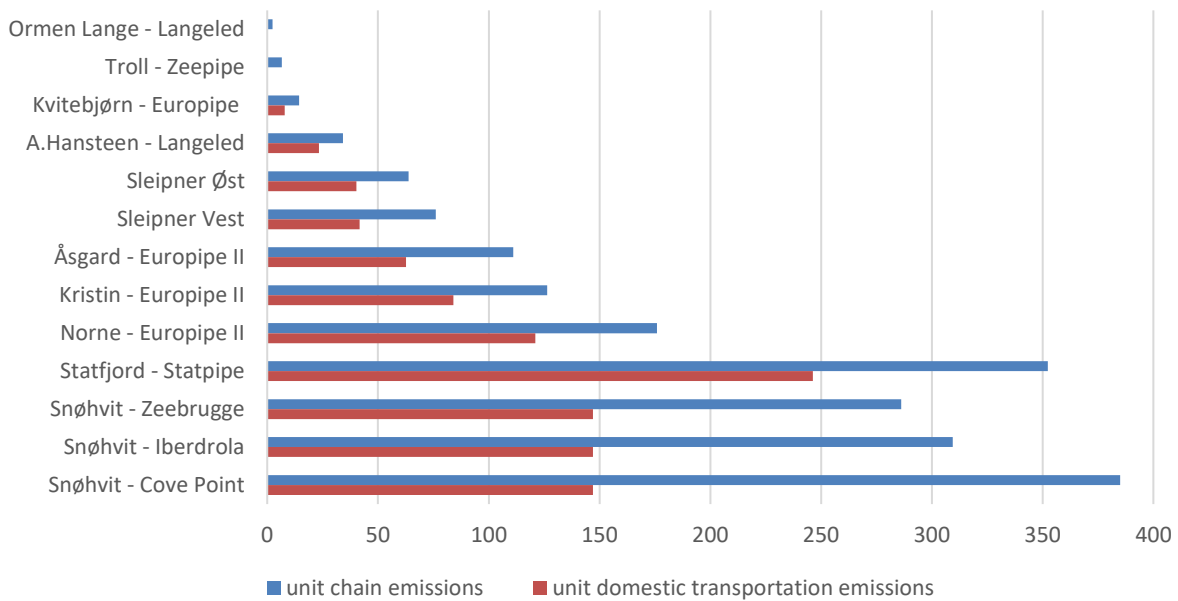


Figure 4.1 Total CO<sub>2</sub> emissions and the domestic part of transportation-related CO<sub>2</sub> emissions (kg/Sm<sup>3</sup>o.e.)

In fact, the infrastructure development decisions in the gas transport sector internalize only the domestic part of the transportation-related emissions, through the respective environmental taxes and quotas. The discussion of the carbon prices lays out of the scope of this paper; however, it is worth mentioning that the increase of these prices can affect significantly the transport infrastructure development in the gas sector in the future.

The evaluation and analysis of emissions to air from gas production and transportation chains can contribute to decision-making regarding new major infrastructure development, especially in remote areas like the Barents Sea. The choice between the expansion of the existing LNG solution and a new pipeline, which would connect gas fields in the Barents Sea with the existing pipeline network, not only has long-term economic consequences but also considerable environmental impacts. Therefore, the evaluation of the environmental effects of infrastructure development alternatives, according to their social value, represents an important component of the socio-economic analysis of the project.

In light of the increasing environmental concerns and stricter environmental policies of many gas consuming countries, infrastructure development decisions of gas producers may affect their competitive positions in the markets. For example, the existing pipeline network may give Norway an advantage in terms of 'green' competition in supplying Europe's energy needs in the long run. According to the International Association of Oil & Gas Producers (2015), the world average CO<sub>2</sub> emissions per tonne of hydrocarbon production is about 130 kg, while the corresponding number for Norway is 55 kg (Gavenas et al., 2015). In combination with the low emission intensity of export transportation, it makes Norwegian gas an important contributor to Europe's transition to the 'green' economy.

## 5 Conclusions

The aim of this study was to estimate and compare the environmental footprint of pipeline and LNG chains. The results show that pipeline chains have a significant advantage over LNG chains with regard to CO<sub>2</sub>, CH<sub>4</sub> and nmVOC emissions. However, the environmental footprint of pipeline chains varies significantly, depending on the chain configurations. The isolated analysis of the CO<sub>2</sub> emissions from the transportation segments of the chains also proves the superiority of pipeline chains. Considering the CO<sub>2</sub> emissions only from the domestic part of transportation chains, we found that although pipeline chains still outperform LNG, the transportation-related emissions of the longest pipeline chain, which uses gas-based power for compression, are not significantly lower than the domestic emissions of LNG transportation.

The complexity of the considered network of fields and pipelines required some simplifications and assumptions regarding the allocation of the emissions among the processes. An even higher precision level would therefore be achievable through further consideration of some important aspects. One of these is the fact that due to freezing constraints in the LNG process system, almost all the CO<sub>2</sub> is removed from the feed gas while the pipeline gas has a CO<sub>2</sub> content of up to 2.5 mol%. Therefore, the final combustion of these two products will have different CO<sub>2</sub> emissions to air.

It should also be noted that the Norwegian gas sector has specific characteristics such as offshore deep-water field locations, relatively long distances to the market, mainly subsea pipeline transportation, low sulphur content in gas and regulation, which allows gas flaring only for safety reasons. These factors affect the estimates obtained in this study and require careful consideration before our findings can be applied to other settings. However, the results and conceptual model developed would prove useful in the analysis of alternative gas transportation systems in other parts of the world.

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