UNIVERSITY OF NORDLAND

BODØ GRADUATE SCHOOL OF BUSINESS

MASTER THESIS

Master of Science in Energy Management

EN310E

Investment analysis:

The increased value of selling LNG on spot instead of long-term contracts

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Sammendrag

Produksjon og salg av LNG har tradisjonelt vært sikret med langsiktige kontrakter på grunn av store investeringer. I de senere år har spot og kortsiktig salg blitt stadig mer brukt til å balansere etterspørselsendringer påvirket av globale begivenheter. Likevel er markedet ikke effektivt, og det er tydelige prisforskjeller mellom de regionale markedene.

Transport av LNG tilbyr fleksibilitet og er den viktigste delen av verdikjeden. Denne oppgaven ser på verdien av å investere i et LNG-skip for en norsk produsent. Fire fiktive caser ble laget for å undersøke verdien av å ta risiko, dvs. selge på spot i stedet for langsiktige avtaler. Hvert case representerte forskjellig risikostyring og reiseavhengige alternativer. De fire casene var varianter av eksport til Storbritannia og Japan. En tidsseriemodell ble tilpasset til hver av de historiske prisene i de to markedene. Tre ulike prisscenarioer ble lagd ut fra de statistiske prognosene og en strategisk industrianalyse.

Casene ble først analysert hver for seg ved å finne netto nåverdi og internrente. For å kunne konkludere hva verdiforskjellen mellom salg på spot eller terminkontrakt ble Δ nåverdi sammenlignet i de forskjellige prisscenarioene. Undersøkelsen fant spotsalg til Storbritannia, i både medium og høyt prisscenario til å gi en mye høyere avkastning. Bare i det pessimistiske scenarioet viste en sikret posisjon å gi den høyest nåverdi. Det var interessant å finne at det britiske markedet ga en høyere avkastning enn det japanske. Dette skyldes den store forskjellen i antall dager som kreves for en rundtur og volumene som transporteres.

Preface

This thesis represents the end of our Master of Science in Energy Management program at the Bodø Graduate School of Business. We have over the last two years been studying the complexity and dynamics of the oil, gas and electricity industry. The program is a joint Norwegian/Russian program with a focus on the characteristics of each industry, and how the geopolitical energy situation is a portrayal of the world economy. During the program we were very intrigued by the developments of the LNG industry.

Writing this thesis has been a learning process on many levels and has given us a deep insight in an industry we believe will become increasingly important in the years to come.

We wish to thank our supervisor Øystein Gjerde who has been of great help throughout the process.

Bodø Graduate School of Business, 20. May 2014

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Abstract

Producing and selling LNG has traditionally been hedged with long-term contracts due to the massive investments required. In recent years spot and short-term sales has been increasingly used to balance demand changes affected by world events. Yet, the market is not effective, and there are evident price differences between the regional markets.

Transportation of LNG offers flexibility and is the most important part of the value chain. This paper looks at the value of investing in a LNG carrier for a Norwegian producer. To investigate the value of taking risk, i.e. selling on spot, instead of long-term sales and purchase agreements, four fictional cases were created. Each case represented different risk management positions and voyage alternatives. The four cases were variations of export to UK and Japan. A time series model was fitted to each of the historical prices in the two markets. The statistical forecasts from the two models were further supplied with judgmental forecasting based on a strategic industry analysis, creating three different price scenarios.

The cases were analyzed by finding a net present value and internal rate of return. To make a conclusion the Δ net present value of selling on spot and forward contract was compared in different future price scenarios, and thereby representing the increased value. The research found spot sales to the UK, in both medium and high price scenarios to yield a much higher return. Only the bearish scenario proved a hedged position to give the highest net present value. It was interesting to find that the UK market gave a higher total return than the Japanese. This was due to the major difference in days required for a round trip and the volumes transported.

TABLE OF CONTENTS

List of figures

List of Abbreviations

BOG – Boil-off gas

CIF – Cost Insurance and Freight

CO_2 – Carbon dioxide

DES – Delivery Ex Ship

EIA – Energy Information Administration

EU – European Union

FLNG – Floating Liquefied Natural Gas

FOB – Free On Board

FPSO – Floating Production, Storage and Offloading

FSRU – Floating Storage and Regasification Unit

GEM – Global Economic Monitor

GIIGNL – The International Group of Liquefied Natural Gas

HHV – Heating Value

IEA – International Energy Agency

IGU – International Gas Union

LNG – Liquefied Natural Gas

LNGC – LNG Carrier

LPG – Liquefied Petroleum Gas

MHPA – Milford Haven Port Authority

NBP – National Balancing Point

NGL – Natural Gas Liquids

NO_x – Mono-nitrogen oxides

NPD – Norwegian Petroleum Directorate

NSR – Northern Sea Route

OECD – Organization for Economic Cooperation and Development

SPA – Sales and Purchase Agreement

UK – United Kingdom

US – United States

WI – Wobbe Index

Units

Btu – British thermal unit

GBP – British pounds

km – Kilometers

mmBtu – Million British thermal units

MT – Million tons

MTPA – Million tons per annum

nm – Nautical miles

NOK – Norwegian kroner

USD – United States dollars

1 INTRODUCTION

The LNG (liquefied natural gas) industry is characterized by very cost-intensive assets. Its development started off slowly, as most of the natural gas volume historically has been tied up in pipelines with long-term contracts. Reduced costs and technological refinement has in the later years made LNG a commercial and viable alternative. To justify the massive investments, trading of LNG has been defined by bilateral long-term contracts of 20+ years duration.

Since the early 2000s it has become a regular observation that regional gas markets are increasingly influenced by events in different parts of the world. The shale gas revolution in the United States, the economic recession in Europe, green energy politics, increased demand from non-OECD countries and the Fukushima nuclear accident in Japan have all had impacts on gas supply, demand and pricing. The correlation between price spikes and historic events is obvious, and has caused price differences between the regional markets. However, no major market in today's globalized world acts totally independent from one another. Low flexibility offered by pipeline infrastructure has caused a significant increase in trade volumes of LNG to support the demand growth for natural gas globally. The growth, triggered partly by electricity and gas industry liberalization, has increased investments in liquefaction, regasification and LNG shipping capacity (IGU, 2014).

The thought of converging gas prices was a widespread conjecture not so long ago. In a perfect market the only differences in price between regional markets is the cost connected to the transportation of LNG. The idea that international trade of LNG could connect major geographically distanced markets and link their prices is a long way from the reality today. Japan's shutdown of nuclear reactors after the Fukushima disaster in 2011 has intensified the already high energy demand in the Asian market. One could say that Japan's energy deficit is driving the Asian LNG price. The disparity between the regional markets has presented the possibility of executing arbitrage. Applying the arbitrage pricing theory, the market should not allow for such persisting arbitrage opportunities. However, three years after the disaster, the regional price differences are still evident. During the spring of 2014, the price has been around 5 USD/mmBtu in the United States (US), and almost 4 times higher in Japan, at just short of 20 USD/mmBtu. The European price has been somewhere in the middle at 11

USD/mmBtu (Platts, 2014). Compared to other energy commodities this price spread is significant, and has caused momentum among traders and suppliers to take advantage of it.

According to natural gas analyst Terje Halmø, Norway has a reason to be worried. He claims that in order to improve the prospects of revenue in the future, Norway and Statoil has to look towards the Asian market (Tollaksen, 2014). Norway as a supplier of natural gas has tied up 95% of its volumes via pipelines to Europe (NPD, 2014). This could put Norway in a risky situation in regards to market-exposure and price volatility, as a price drop of only 1 USD/mmBtu in Europe could mean an and annual income loss of 20 billion NOK (Tollaksen, 2013). By focusing more on LNG and the possibility of shipping through the Northern Sea Route (NSR), the dependence could be reduced while increasing the pressure on the European market.

The solution seems obvious. However, utilizing the higher prices offered in the Asian market requires ability of doing so, and that could be difficult, as most of the volumes have been managed through long-term agreements. Conversely, there is an ongoing shift towards more trade in spot and short-term markets, which now make up 33% of total LNG sales (IGU, 2014).

1.1 Research questions

The trade of LNG is highly affected by prices and global events. This market risk has had a great influence on the risk management in the industry. The widespread use of long-term agreements reflects the actors' risk appetite and the preferring of safe and steady cash flows. Despite the flexibility, LNG has therefore been regarded as a floating pipeline. Yet, volatile prices and significant price spreads between the regional markets has increasingly strengthened the role of spot and short-term sales. Even though Europe and Asia have great distances between them, cargo-diversions from Europe to Asia has been done both successfully and profitable. Norway exports 5% of their natural gas as LNG, and is in a great position to supply them both. However, spot export is also highly affected by the cost of transportation.

On this basis we have chosen the following research question:

- ***What is the increased value of investing in a ship selling LNG on spot instead of a long-term contract for a Norwegian producer?***

To help us properly investigate the increased value we have formulated a set of sub research questions:

- ***What is the value of investing in a ship selling LNG on a long-term contract to the European market for a Norwegian producer?***

- ***What is the value of investing in a ship selling LNG on spot or short-term contracts to the European market for a Norwegian producer?***

- ***What is the value of investing in a ship selling LNG on spot or short-term contracts to the Japanese market for a Norwegian producer?***

- ***What is the value of investing in a ship selling LNG on spot or short-term contracts to the European and/or Japanese market for a Norwegian producer?***

- ***Is there an added value of having the possibility to export LNG with spot or short-term contracts versus having a secure long-term contract towards Europe?***

The approach of this master thesis is from a Norwegian natural gas supply view, with LNG export possibilities from the Snøhvit field in Hammerfest. The producer of LNG will invest in a LNG carrier for export restricted to Milford Haven in the United Kingdom (UK), or Yokohama in Japan. By using a forward contract we remove the risk of fluctuations in market prices, but at the same time commit to always deliver to the same port. Selling on spot allows us to monetize the highest price in the markets, while being exposed to market risk. Given different price scenarios created, selling on spot could yield the highest net present value of investing in a ship.

1.2 STRUCTURE OF THE THESIS

The thesis is divided into nine chapters:

1. Introduction
2. Liquefied natural gas
3. Natural gas markets
4. Methodology
5. Presentation of the cases
6. Strategic industry analysis
7. Price forecasts
8. Investment analysis
9. Conclusion

After the introduction we will describe the LNG industry and what liquefied natural gas is. Then, in chapter 3 we will explain factors that affect the natural gas price, and clarify the price situation in the regional markets. In the methodology chapter we go through the choice of research design, data used, and the method for price forecasting and analyzing an investment. Thereafter, we present the four different cases used in the investment analysis. In order to do a good investment decision, and to supply the statistical forecasts, we conduct a strategic analysis of the LNG industry in chapter 6. In chapter 7 we analyze historical prices, and fit a model to create forecasts. These are merged with judgmental forecasting, making three different price scenarios: high, medium and low. In the investment analysis we go through the assumptions, which lay the basis for costs and cost of capital for the different cases. The cases will then be analyzed to answer the sub research questions. Lastly, in the conclusion we will compare the analyses of the cases and use them to answer the main research question.

2 LIQUEFIED NATURAL GAS

This chapter will give will give a description of the LNG industry. The focus will lie on the value chain and its key components: Storage and transportation, as this positions LNG as the flexible option. Further, we will define LNG arbitrage occurring from the price spreads, and some of the main features of LNG trading.

2.1 THE ROLE OF LNG

LNG possesses a number of advantages, including flexibility and ease of transport. These are the reason for its growth, and will be instrumental in the years to come, especially to meet Asian demand. Over the last 30 years the demand for natural gas has been rising at an average rate of almost 3% per year (Total, 2012). It is also projected to be playing an important role in the global energy mix in the future.

LNG has appeared as an increasingly core feature of the global gas balance during the past two decades. Since the year 2000, the growth of LNG use has been roughly 8% per year (Total, 2012). LNG's contribution to meeting increased natural gas demand has been growing continuously. Even though LNG trade fell by 1,6% in 2012, compared to 2011, after 30 years of uninterrupted growth, it amounts to almost 10% of global gas consumption (IGU, 2014). In 2012 the trade flow was 237,7 million tons (MT), where of which Japan and Korea imported 52%, up from 4% in 2011 (GIIGNL, 2013). Total, one of the most experienced LNG actors and a world-class player, projects that the LNG production will expand steadily to 370 MT in 2020 (Total, 2014a).

LNG is liquefied natural gas coming from petroleum production. In order to make natural gas liquid is has to be cooled down until it reaches a temperature of -163°C. It then occupies only 1/600th of its normal gaseous volume at atmospheric pressure (Linde Engineering, 2014). Building a plant that is able to cool down the gas like this is costly. However, by doing so, practical transportation across great distances becomes possible when there are geological and/or political barriers that do not allow the construction of pipelines. When the LNG carrier (LNGC) reaches its destination, the LNG is returned to gaseous form at a regasification facility by heating it up. Thereafter it is piped to homes, businesses and industries, just as any other natural gas.

2.1.1 Overview of the LNG value chain

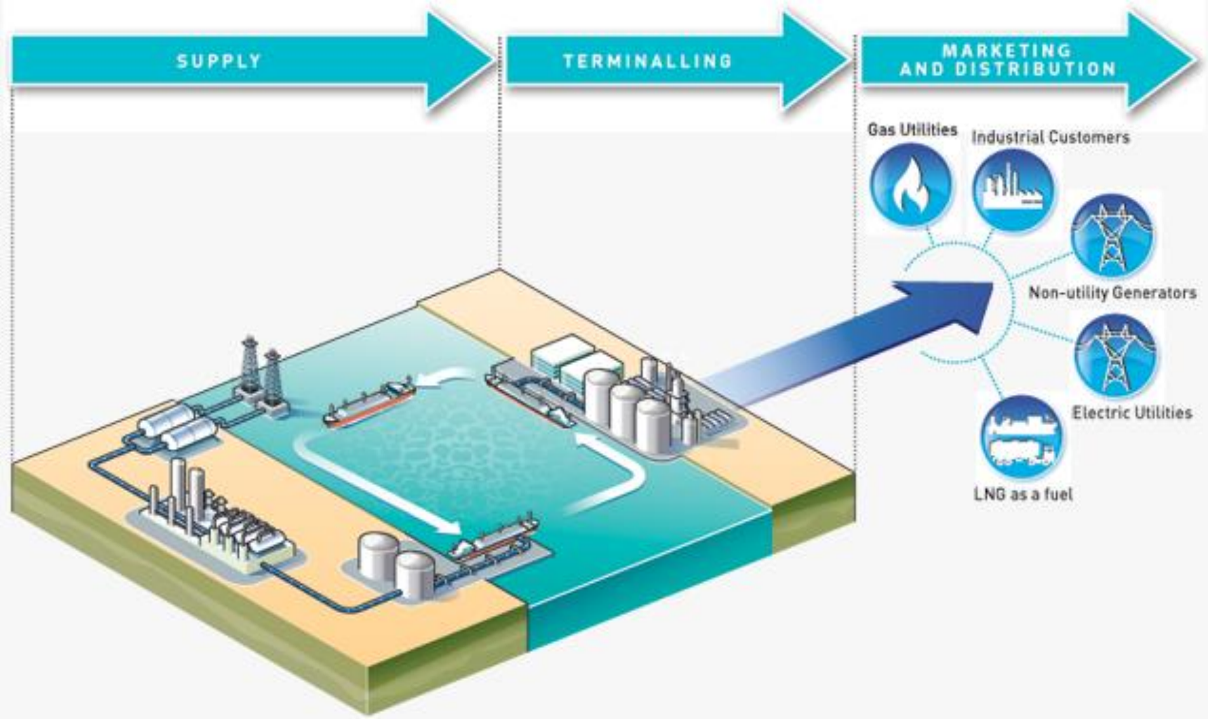


Figure 2.1: The LNG Value chain (GIIGNL, 2014).

The different stages of the LNG value chain can generally de described by the following:

- Natural gas production: the process of finding and producing natural gas for delivery to a processing facility.
- Liquefaction: the conversion of natural gas into a liquid state so that it can be transported in ships.
- Transportation: the shipment of LNG in specially designed ships for delivery to markets. The key component of the value chain.
- Regasification: conversion of the LNG back to the gaseous form by passing the cryogenic liquid through vaporizers at receiving terminals.
- Storage: LNG waiting for shipping at the liquefaction plant. LNG receiving terminals and regasification facilities also store LNG before it is re-gasified for pipeline transportation or reloaded to another LNGC.

- Distribution and delivery of natural gas goes through the national natural gas pipeline system to the end users.

2.2 LNG TRADING

LNG can be sold at any step of the value chain. Predominantly it is sold under long-term contracts between liquefaction plants and gas marketers and/or power producers. According to Total (2014b) signing sales and purchase agreements (SPA) is imperative to building liquefaction facilities, because they determine the economic viability of the project, which usually is an investment of several billion dollars. SPAs enable risk sharing, between the LNG sellers carrying the price risk and buyers whom the volume risk is transferred to. Spot trading of LNG emerged about a decade ago, with the deregulation of the gas market in Europe, and the growth of LNG production and transport capacity. The change in market conditions has given market players an increasing degree of flexibility.

Long-term contracts are still central in the LNG industry, but some significant changes have taken place in the latest years. The destination clause, which has been standard in long-term contracts, was eliminated from some new-signed contracts to increase flexibility (Hartley, 2013). In addition, the number of uncommitted LNG ships has been increasing. LNG shipping is crucial for LNG trade, and with a limited number of vessels not committed to SPAs, the possibility for LNG spot trade also becomes limited.

2.2.1 LNG ARBITRAGE

It has even become more acceptable in the industry for contractually committed LNG, with a specific destination, to be diverted to another market through a mutual agreement between seller and buyer.

An arbitrage in a commodity is the profit making market activity of simultaneous buying and selling in different markets or in derivative in order to take advantage of differing in prices for the same asset, making a riskless profit (Eydeland and Wolyniec 2003).

A study done by the Oxford Institute for Energy Studies interpreted LNG arbitrage as follows:

> LNG Arbitrage can be defined as a physical cargo diversion from one market to another, which offers a higher price. The diversion of the cargo can be regarded as arbitrage if the cargo was initially committed to the first market and to the initial buyer in a commercial contract (Zhuravleva, 2009: 2).

The key driver for LNG arbitrage is commercial, and is obviously induced by the economic motivation to take advantage of price differentials between markets caused by supply and demand imbalances and market inefficiencies.

To make the above definition clearer we are going to illustrate an arbitrage model from a seller's perspective. Firstly, we are going to technically illustrate how an arbitrage would happen in the LNG market. The seller of LNG has an initial contract agreement towards a market, a long-term, short-term or spot contract. If the seller then has the ability to sell LNG to another market with a higher price for the same commodity, then there is a possibility to lock in an arbitrage profit. However, it is important for the seller that the price spread between the markets is higher than the transportation cost in order to make it a profitable transaction. If this is the case, the seller then makes a cargo diversion, selling the initial contracted load towards the market with higher price. But, in order to make this transaction happen, the seller is dependent on a third actor. Since the seller has contract obligations towards the initial buyer, he has to provide natural gas from another source, for instance LNG spot or local natural gas. Summing up from the descriptive explanation, LNG arbitrage requires:

$\mathrm{P_{EB}} > \mathrm{P_{SM}}$
$\mathrm{P_{EB}} > \mathrm{P_{LGM}}$

Where:

- $\mathrm{P_{EB}}$ – LNG price at the end buyer's market
- $\mathrm{P_{SM}}$– Price of LNG at the spot market
- $\mathrm{P_{LGM}}$ – Price of the LNG at the local gas market

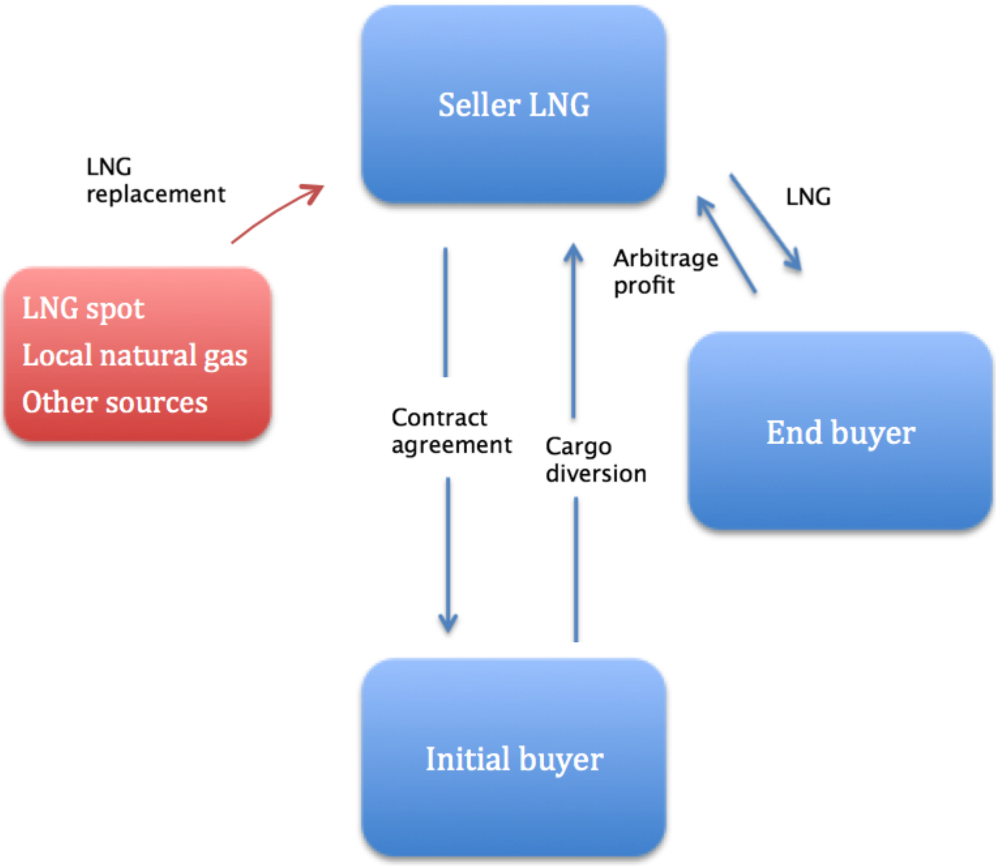


Figure 2.2: Arbitrage model from a seller's perspective (based on Zhuravleva, 2009).

The previous section was a purely technical description of an arbitrage; however there are often contractual clauses, which can spoil profitable opportunities. Destination clauses and ex-ship contractual terms make arbitrage almost impossible. If such terms exist, which they often do in the LNG industry, there is the possibility of sharing the arbitrage profit with the initial buyer in order to break the contract clause.

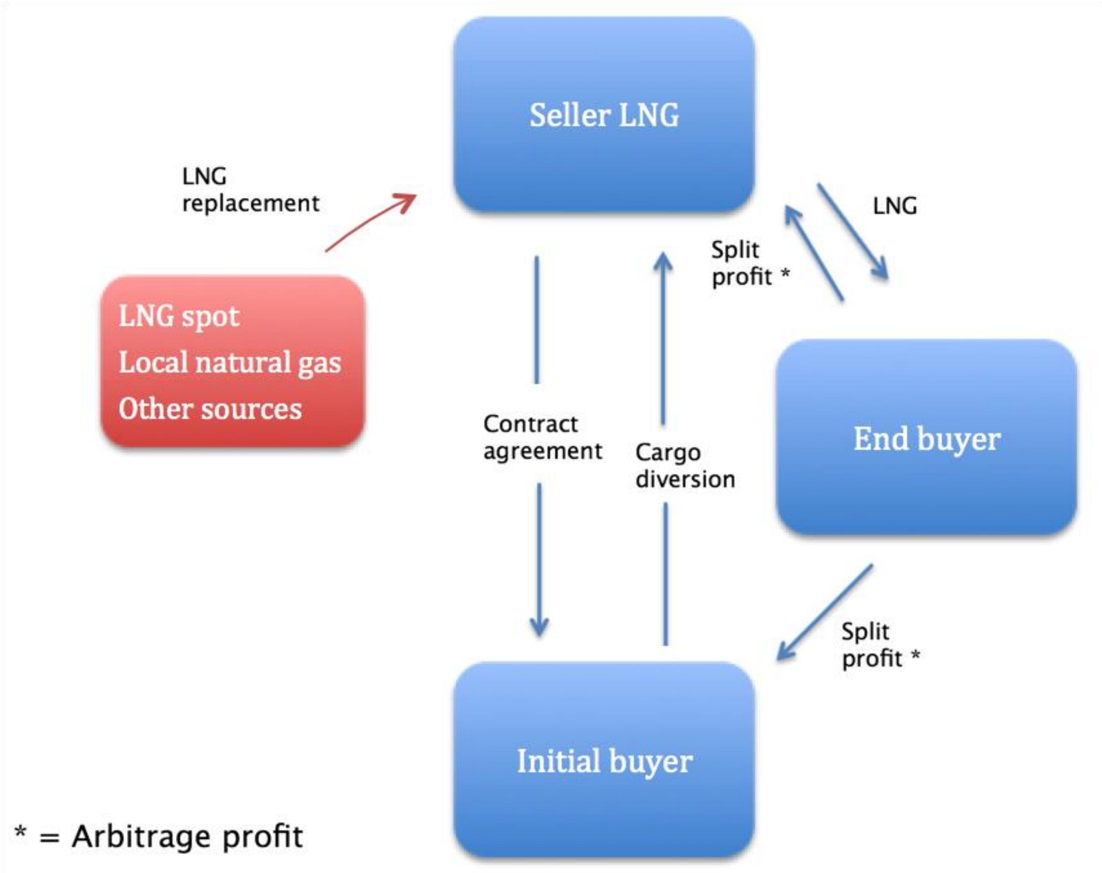


Figure 2.3: Arbitrage model from a seller's perspective with contractual limitations (own model).

2.2.2 Spot and short-term market

It was only after 2005 that the spot and short-term trade started to experience growth. By that time its share of the total LNG trade had grown to 8%, whereas before 2000 it consisted only of a negligible part (IGU, 2014). During the years 2007 until 2010, the spot and short-term trade accounted for 17% to 20% of total trade. The years of 2011 and 2012 had an array of factors that drove the LNG spot and short-term market to new heights. These factors include (IGU, 2014):

- The large growth of the LNG fleet, which made the long-haul transportations to the spot market possible. Mainly from the Atlantic to the Pacific.
- The increased use of destination flexibility in the contracts. Primarily form the Atlantic Basin and Qatar.
- The new permutations and linkages between buyers and sellers as a consequence of the increase in number of exporters and importers.

- The significant increase in demand in Asia and South America.
- The lack of domestic production or infrastructure supporting pipeline imports in Japan, Korea and Taiwan, meaning they have to resort to the spot market to manage any sudden changes in demand, e.g. Fukushima incident and its implications.
- The sustained violation of parity between prices in the different basins, making the arbitrage opportunities a high-ranking part of the monetization strategy.
- The relative decrease of gas competitiveness to other fuels, mainly in Europe from the economic crisis and the increased competitiveness of coal. The latter is closely related to the so-called shale gas revolution in the US, which freed up volumes of gas to be to be re-directed elsewhere. In addition, it dramatically decreased coal's competitiveness in the US, leading to increased use of coal in Europe.

2.2.3 LNG RELOADING

Reloading of an already discharged LNG cargo back onto a carrier for export appears illogical. However, this practice has become an increasingly important factor driving LNG flows from Europe over the last two years. Reloading activity mainly relates to deliveries of LNG that are bound to specific locations by contractual constraints. Even though this evidently is inefficient, significant profits have been made by reloading gas from Spain, Belgium and France for export to higher priced markets (GIIGNL, 2013).

There are two main reasons for reloading in Europe (Timera Energy, 2013b). Firstly, many LNG supply contracts have fixed destination clause constraints. The delivery is ex ship (DES). Secondly, there is a premium for Asian LNG spot over European gas prices. Only a subset of the LNG supply contracts to Europe has fixed destination clauses. The majority of the LNG supply into European receiving terminals is contractually divertible as said in the SPA, or alternatively by renegotiation between seller and buyer. The inflexible supply contracts are to Spain, France and Portugal, including Qatari supply to the Belgian Zeebrugge terminal (Timera Energy, 2013b). Even if there is a DES agreement, after it is discharged in to the storage tanks it belongs to the receiver/terminal capacity user and can then be shipped anywhere. This has led to adaptation to terminals, enabling them to re-load from the storage tanks into a LNGC, not purely for discharging.

2.3 The liquefaction process

Just as with crude oil, natural gas can be of different qualities. Natural gas from the wellhead contains a mixture of methane and heavier hydrocarbon gases, including small quantities of other unwanted components. These are nitrogen, helium, carbon dioxide, sulfur compounds and water. Before any liquefaction process can take place, the natural gas has to be treated. The pre-treatment involves removing the unwanted components and separating some of the heavier components. By doing so there will not be any solids formed when the gas is cooled down. This also makes the product compatible with the end users LNG specification, i.e. heating value. Gas interchangeability and heating value will be discussed later on. It also reduces the transportation volume. Normally, the end product consists of 85-95% methane, with some ethane, propane, butane and traces of nitrogen, depending on where it is produced, and where it is planned to be used (Statoil, 2009). As LNG is mostly methane, it shares its attributes, being odorless, colorless, non-corrosive and non-poisonous. NGL, LPG, condensate or pure components of ethane, propane and butane are sometimes extracted and fractioned in tailor made processing plants because of their potential higher sales value in some regional markets.

2.4 Advantages

The increased use of natural gas can be explained by its more environmental friendly footprint and its potential energy. The combustion releases less greenhouse gas than the other fossil fuels, and does not leave any unburned residues, soot or particulates. The high calorific value in natural gas allows power plants using latest technology to achieve high energy efficiency through cogeneration and combined cycle configurations, reducing both energy consumption and emissions.

One of the main reasons for the LNG sector to emerge is that LNG allows transport of gas in a technically and economically manner. Firstly, the use of LNG offers an alternative to the cost and challenges related to building a pipeline infrastructure. The LNG value chain creates opportunities for gas-producing and gas-consuming countries. Huge reserves located far from the consumer zones can be exploited by exporting LNG with tankers. Meaning that liquefaction of natural gas creates new market opportunities, and generates revenues that will stimulate the economy of the producing country. In addition, liquefaction offers an alternative to gas flaring associated with crude oil production. The LNG value chain also enables consumer countries to diversify their energy supply, and thereby reduce their energy dependence on the producing countries that supply via pipelines. As opposed to gas transportation through a pipeline, LNG cargoes can be diverged en route. This promotes the flexibility that the consumers need to manage their supply, and enables the producers to optimize the commercial value of their assets. Increased short-term LNG trading related to market deregulation has stimulated the flexibility.

2.5 Challenges

The LNG sector is complex and capital-intensive. Managing a project will demand a comprehensive expertise, which only a few operators possess. There are considerable investments needed to developing LNG projects. Implementing a typical 8 MTPA LNG chain between the Middle East and Europe will come to about 17 billion dollars, normally broken down like this (Total, 2014b):

- *1.5 billion USD* to develop the gas fields that will supply the plant
- *12.5 billion USD* to build the liquefaction complex
- *2.5 billion USD* to build ten LNGC
- *0.5 billion USD* for the regasification of the cargoes

Being able to handle such enormous projects financially is one thing, but there are numerous and diverse inter-dependent fields of expertise required to investing and managing such expensive projects. The know-how needed reflects the projects scale and range of risk. The technical competence must cover the whole value chain: exploration and production of resources (natural gas or gas associated with oilfields), liquefaction, process engineering, plant configuration engineering, construction and management of a LNGC, safety of shipping operations, ensuring safe integration into the environment (sometimes in harsh climate, e.g. arctic or desert regions) and more (Total, 2014b). Due to the complexity of these large-scale projects, a solid and contractual framework to implement and involve a range of different players, disciplines and businesses is needed. Further, the extensive knowledge about the global gas markets and the ability to forecast price trends are necessities for bargaining about long-term LNG sales contracts.

Lastly, the time needed from the first planning phases, throughout to the first delivery of the first cargo will require a long-term investment capacity. The “simplest” project takes about ten years. Even before any construction of a plant can start, which itself takes about four to five years, it will take at least five years to secure all the conditions required to do the final investment decision. These conditions include (Total, 2014b):

- Securing gas supply to the liquefaction plant (certification of reserves, design of the development scheme, agreements on the shares of each supplier, signing of gas supply agreements, etc.).
- Guaranteeing supply to markets via long-term SPA, normally with terms of twenty years and longer.
- Establishing plant ownership.
- Finding the “optimal” technical design of the liquefaction process and plant facilities.
- Defining the fleet of carriers that will be used for transportation.
- Securing future access to regasification terminals for cargoes.
- Organize a financing plan for the whole project.

Summed up, managing a huge project at this kind of scale requires optimal synergy between the many interdependent and complementary fields of expertise involved.

2.6 Technical disadvantages

Durr et al. (2005) point out that cooling natural gas down has its disadvantages. Firstly, the energy and the processing equipment required to reduce the temperature is expensive. Usually 10% of the natural gas from the feedstock must be burned to provide the energy needed for the cooling process. Seawater, freshwater and air are used as cooling mediums, often in combination. The amount of fuel used will differ from plant to plant, but the energy needed is still significant and cooling machinery is expensive.

Secondly, handling the low temperature requires special materials. While pipelines operating in ambient temperatures can be made out of carbon steel, LNG has to be stored in more expensive materials like aluminum, stainless steel and high nickel steel. Hence, storage and transportation of LNG is more costly than transportation of other hydrocarbon products.

2.7 The economy of scale of liquefying natural gas

The first commercial liquefaction plant was in Arzew, Algeria in 1964, even though the technology had existed for decades (Center for Energy Economics, 2014). The capacity of the Algerian LNG train (liquefaction and purification facility) was 0,4 MTPA. In 2004 Conoco Phillips did a technical study of train sizes, where 5 MTPA came out as most cost effective (Eaton et al., 2004). They also concluded that the size of a single LNG train of 8 MTPA was feasible, and would be most suitable for expanding plants targeting distant markets. This would also require an almost unlimited gas supply. Today, 10 years later, the Qatargas 2 plant consists of two LNG trains with the capacity of 7,8 MTPA each (Qatargas, 2014a). The reason for this development of greater sizes is advancements in train technology and design, which has improved the economy of scale.

The actual breakdown of the costs is highly dependent on the plant (Durr, et. al., 2005). The plant capacity determines to some extent the size of the storage and loading facilities, which again sets the ship size. Increasing the train capacity, without increasing the size of LNG storage and loading, would improve the total plant cost. However, this would also lead to a requirement of more frequent ship loadings.

According to Kotzot et al. (2007) the total cost for a LNG plant can vary by 100% or more and are highly dependent on site-specific factors. These are geographical location, technical specifications and financing. Even though the technicality may be the same, a different location results in different ambient air temperature or closeness to the customers. For example, given the same plant configurations a 5^{o}C higher temperature profile will decrease the production by roughly 4% (Kotzot et al., 2007). Therefore it seems logical that no plant is identical, and that both capital expenditures and variable cost differ.

Even though it seems like the primary driver of the total plant cost is the LNG train, it is not so. Caswell et al. (2012) emphasize that the LNG train is an important component of the costs, but the civil and infrastructure costs are the largest of them. These include:

- Soil improvement: blasting rock, clearing land, and driving piles
- Seismic protection for LNG tanks, equipment, structures, and buildings
- Marine terminal development: jetty length and depth, dredging, and tug support
- Accommodation villages: permanent and temporary housing support

The cost of construction is primarily driven by the location, and it is a combination of man-hours, labor cost and productivity over four to five years. However, the important thing to remember is that even though if two LNG plants were to have the same production capacity, these projects would not be guaranteed to be of similar cost. For example, the construction costs of current LNG projects in Australia are typically two to three times higher than for other locations (Songhurst, 2014).

2.8 Key components of the value chain

2.8.1 Storage

At both liquefaction, and receiving and regasification facilities LNG can be stored. Since temperature and pressure are directly proportional to each other, the tanks used to store LNG have to keep the liquid cold and independent of pressure. This is done in insulated double-walled tanks, specifically made to hold LNG. If the vapors are not released, the pressure and the temperature within a tank will keep on rising. To keep the temperature constant (auto-refrigeration) the boil-off gas (BOG) is allowed to escape the tank, and is then collected to be used as fuel or cooled down again (National Grid, 2014). In other words, as long as auto-refrigeration is done, LNG can be stored as long as desired. The cost however, would be depending on the fuel price and the lack of storage for further supply or production of LNG.

As there are several kinds of storage tanks to choose from, the decision of which to use is usually based on the land available and cost (Durr et al., 2005). All of them have secondary spill containments, which defines the primary difference between the single, double, and full containment. The secondary containment ensures that any leak or spill is fully contained and isolated from any public near an onshore LNG plant. Tank capacities of 140 000 – 160 000 m^3 are common, but the industry has started using up to 200 000 m^3 storage tanks (Durr et al., 2005).

2.8.2 Transportation

Pipelines vs. LNG

Energy distribution is an extremely important component in the petroleum value chain. Natural gas is considered abundant; however more than one-third of global reserves are classified as stranded (Energytribune, 2007). In order to monetize these resources, economic ways of distributing are necessary.

For offshore transportation of natural gas, pipelines are the most common. However, for longer distances, e.g. between regional markets, pipelines are too costly. The general guideline is that LNG-transportation breaks even with onshore pipelines at 3200 km and with offshore pipelines at 1600 km (Durr et al., 2005).

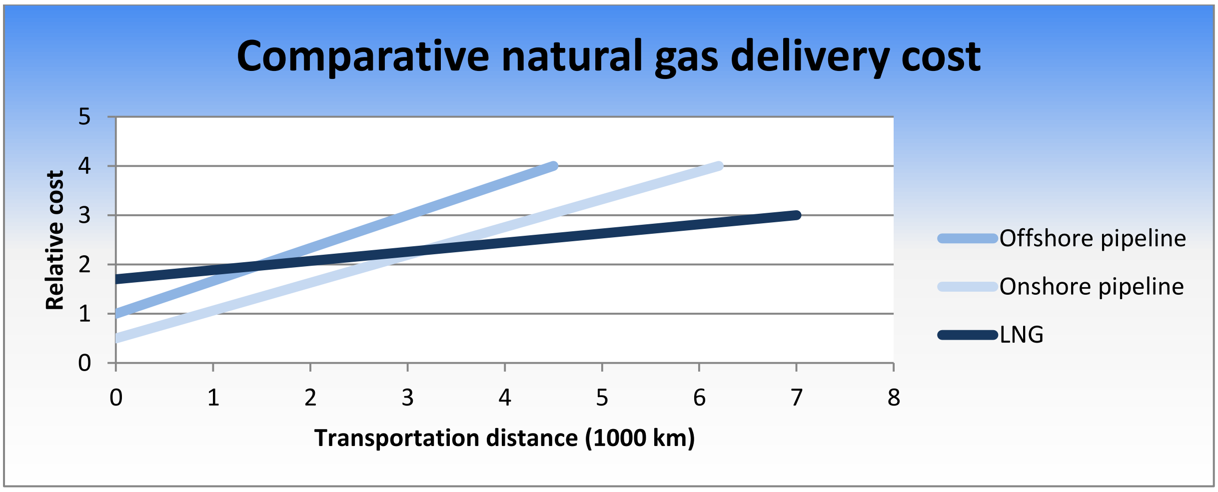


Figure 2.4: Gas transportation costs (Durr et al., 2005)

In determining the most economic transportation method for natural gas, distance and volume are key factors to consider. LNG is more competitive for long-distance routes compared to a pipeline, as overall costs are less affected by distance. Supplying natural gas form Middle East to Europe through LNG allows a cost saving of up to 30% measured up against pipelines. LNG rarely competes directly with pipelines because of economic-zones and field size, which also comes into play in the evaluation of distribution.

LNG shipping

The shipping of LNG is very much alike onshore storing, except on a vessel. Just as the storage tanks, the ships have insulation to limit the amount of evaporates. This BOG is sometimes used as a supplement fuel for the carrier. Today, the “standard” cargo size for LNGCs is considered to be around 155 000 m^3 (GIIGNL, 2013). However, a LNG vessel’s size can be much larger. Qatargas has in recent years pioneered the development of LNG carriers, with sizes up to 266 000m^3 (Qatargas, 2014b). In 2013, the ships ordered had an average capacity of 165 000 m^3 (IGU, 2014). Today, the majority of LNG ships have been designed to carry LNG either in spherical tank (Moss sphere design) or in geometric membrane tanks (membrane design). This technology is also be used for floating storage and regasification units (FSRU), described later under 2.9 Technological developments

Using larger ships improves the economies of scale, as they will be able to transport the same planned quantity in fewer trips. However, not every facility can receive larger ships. Modifications to the facility can be done at a fairly low cost, but the water depth could create troubles. If the water is to shallow, the cost jumps are based on the geographical contours and condition, and site location (Durr et al., 2005).

Transportation is a critical component of the LNG supply chain. Being part of an extensive long-term planning, carriers are usually built specifically for a project, and could almost be referred to as a floating pipeline. Increased spot and short-term trade has led to some players designating a small number of LNGC specifically for LNG spot cargo trade. The cost of shipping a LNG cargo is determined by very physical scrutiny of logistics and constraints. The shipping costs also influence the global gas flows and pricing dynamics heavily. This means that they are the key driver of the potential value created by moving gas between different locations, and the level of price spreads between regions in the global gas market. Over the last two years the shipping costs have played a particularly important role in decision making about cargo diversion to markets with higher prices, as global gas prices diverged post Fukushima. The latest publication about the LNG industry by GIIGNL (2013) supports this, and says that both short- and mid-term charter rates remained high during 2012 (just as in 2011), at around 120 000 USD/day and as much as 150 000 USD/day for a conventional carrier of 155 000 m^3. The costs are also a key to understanding to what extent global prices will converge in the future.

After the increase of short-term contracts and spot trades, the demand for LNG shipping capacity can be broken down into two main drivers (Timera Energy, 2014):

1. LNG volume – Higher LNG demand is causing a higher demand for shipping capacity
2. Average travelling time and the proportion of ballast voyages. With a higher number of LNG voyages we get a higher proportion of ballast voyages, requiring more shipping capacity to move a given volume of LNG

In other words, the LNG shipping capacity and shipping charts are fairly correlated with LNG supply and demand, which again are affected by global events. Costs in the LNG shipping industry are expected to be linked to the price for natural gas, if the increased capacity of vessels matches demand for LNG. If there is a surplus of vessels the shipping capacity is likely to go down because of increased competition between shipping companies. Vice versa if there is a vessel deficit, which is expected to increase shipping cost due to more competition for shipping volume.

Globally the LNG fleet consisted of 357 vessels[1] at the end of 2013, while the order book contained 108 vessels. Most of these were ordered in 2011 and 2012 in the anticipation of a higher demand for LNG transportation, following the Fukushima nuclear disaster. In addition, the cyclically weak new-build prices led to a burst of orders LNG projects or LNG off-taker charters instead of signing premium charter deals. Although the fear of a shipping supply glut

[1] Includes only those above 18 000 m^3

reduced this speculative ordering, an excess supply is expected to put a downward pressure on the charter rates in 2014 (IGU, 2014).

2.9 Technological developments

2.9.1 Floating storage and regasification unit

Floating storage and regasification unit (FSRU) is a floating LNG import terminal, which has the capacity to both store and regasify gas from liquid form. With regasification built into the LNG ship, it offers a lot more versatility than a regular LNG ship. Regular ships are dependent on terminals in order to re/degasify and on/offload. Hence, FSRUs are more costly than a LNGC (Schaefer, 2012). FSRU's newfound attractiveness in the LNG industry is understandable when considering the application compared to regular LNGCs and onshore terminals.

A FSRU can be ordered, made and delivered in 2-3 years. Whereas an onshore receiving terminal, from planned to it is in operation, takes 5-7 years (Schaefer, 2012). In an LNG market with high demand and high prices in the Asian-Pacific region, delivery time is essential. In addition, the land-based terminals can cost approximately 700 million USD. Not only do FSRUs get to the market faster, but they are also more economical to build. A new vessel costs roughly 260 million USD, and there is also a possibility to convert old LNGCs for about 160 million USD with 14-16 months delivery time (Schaefer, 2012).

A highly important benefit is the flexibility offered by a FSRU. Since it is not stationary it can be moved to where demand is highest and most profitable, while planned use can help reduce market fluctuations, such as seasonal demand. Also in areas characterized by political and/or economic instability, these vessels are an advantage, as they can just sail away if those elements become too strong. Another major benefit is that FSRUs is not dependent on costly onshore facilities. It only needs modified grid terminals, which is a fraction of the price of a receiving terminal. General cost comparisons must however be treated with caution. Circumstances surrounding floating and land-based constructions can affect the costs significantly, but in general FSRUs may provide faster return on capital (Gupta, 2012).

One big drawback with these units compared to onshore facilities is less regasification capacity. Most have a peak capacity of around 500 million cubic feet per day, compared to onshore, which has twice the peak capacity. There is no doubt that the FSRUs have created bigger opportunities and flexibility in the LNG value chain. With transportation becoming easier this may also allow LNG spot markets to expand (Lingga, 2012).

2.9.2 Floating liquefied natural gas

Floating liquefied natural gas (FLNG) refers to a floating LNG facility. This involves production of LNG directly at a gas field on a floating production, storage and offloading (FPSO) vessel. While being able to store products, LNGC will have to pull alongside, load, and then transport it to the market.

As of today, no FLNG vessel is yet to be completed. Shell is currently building the Prelude FLNG, which will produce LNG off the coast of Australia to supply Asia's growing demand (Shell, 2014a). The hull has been completed and is the world's largest floating vessel, and will probably be the first FLNG (Thomson Reuters, 2013). While being able to withstand strong weather conditions and giant waves the Prelude is planned to produce at least 5,3 MTPA of gas liquids, whereof which 3,6 MTPA is LNG.

By moving the liquefaction process offshore it avoids the potential environmental impact of constructing and operating on land, and laying pipelines (Shell, 2014b). The total cost is then reduced as the civil and infrastructure costs are avoided. Despite the flexibility FLNG offers as a supply solution, building such vessel could be very costly. Debney (2008) suggests that FLNG projects may face large cost over-runs that could occur due to changes in design and re-engineering. Shell has withheld any estimates of Prelude's cost but is speculated to end up around 10-12 billion USD (Thomson Reuters, 2013). Therefore, it will end up at a bit less cost as a land-based plant. The major difference will be the extended inter-dependent expertise required and the new potential risks, but also increased flexibility as it can move around.

2.10 GAS INTERCHANGEABILITY

Gas quality is relevant for both pipeline integrity and combustion, and is specified in terms of requirements. Gas interchangeability however, is only concerned with the combustion, so that gas appliances can perform adequately without compromising the safety, efficiency and operability (Williams, 2009). There are two measures of natural gas properties used for interchangeability: 1) *Heating value* (HHV) and 2) *Wobbe Index* (WI) (Durr et al. 2004). HHV of gas is a measure of the heat released from the combustion for a given amount of gas molecules. Essentially this is the British Thermal Unit (BTU), which is the unit used when selling gas. A BTU is the amount of heat energy needed to raise the temperature of one pound of water by one degree. Not unlike, the WI is a measure of heating value where gravity is taken into account. Natural gas is mainly methane, and some ethane, propane and heavier hydrocarbons. The heating value is affected by the relative amounts of heavier components. More of these, results in higher HHV and WI.

The options to make the gas from LNG interchangeable include adding of liquefied petroleum gas (LPG) or insert gases, such as nitrogen (most common) to reduce heating value, at the receiving terminal. In addition, some liquefaction plants are looking into LPG injection based on long-term agreements, if sufficient quantities, to justify the effort (Durr et al., 2005). Though, the cost of doing such measures is relatively low. There will probably never be a single industry answer of how to do this, as not all liquefaction plants and receiving terminals will have this flexibility built in. Nonetheless, the average WI of LNG produced from different parts of the world hardly differ, meaning that receiving LNG from Norway or Australia would be almost equivalent (GIIGNL, 2013).

2.11 ABOUT THE SNØHVIT FIELD

The Snøhvit gas field was discovered in 1984, and is located in the Norwegian Barents Sea northwest from Hammerfest. The development of the field was approved 7th of March in 2002 by the Norwegian Government. Statoil Petroleum AS is the largest owner with a share of 36,79% and is also operator of the gas field. Petoro AS, a company owned by the Norwegian state and managing the state’s direct financial interest, has a 30% share of the field. Other international petroleum companies which have licenses in the field, are Total

E&P Norway (18,4%), GDF Suez E&P Norway (12%) and RWE Dea Norway AS (2,81%) (Statoil, 2012). At a water depth of 310-340 meters, natural gas is extracted from Snøhvit and is sent through a 160-kilometer long pipeline to the liquefaction plant at Melkøya in Hammerfest. At the plant the gas goes through the liquefaction process and is prepared for shipping with LNGC to the international markets (NPD, 2014).

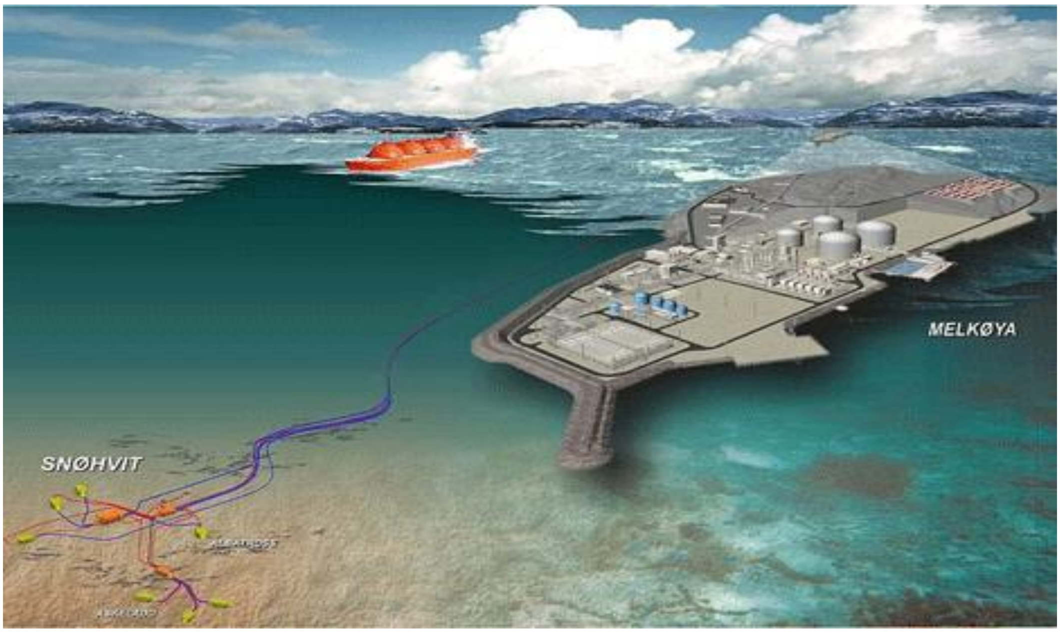


Figure 2.5: Illustration of the Snøhvit field and Melkøya plant (Offshoreenergytoday, 2014)

The Snøhvit field has estimated reserves of 244 billion cubic meters of natural gas, and is the first in Europe to use subsea production platforms (NPD, 2014). The project is installed with a carbon dioxide capture and storage facility located 2,6 km beneath the seabed of the Snøhvit field, with a 153 km pipeline for reinjection. Storage capacity of this facility is 700 000 tons of carbon dioxide annually (Hydrocarbons-technology.com, 2014). The purpose of these reinjections is to reduce the CO_2-emmisions, and thereby reduce the pollution effects of the petroleum activity. The Snøhvit field is the first of its kind, with carbon capture and storage installation (NPD, 2014).

There have been some problems at the Melkøya facility causing shutdowns four times, after the start-up in September 2007. Statoil has had problems with both the onshore plant cooling system and the reinjection system, but has a robust and long term plan to solve the problems (Helgesen, 2013).

The production capacity of the Snøhvit field is very relevant for exporting capacity to the market. A capacity of 4,3 MTPA is equivalent to 5,6 billion cubic meters of LNG. With these estimates, the consortium needed four 145 000 m^3 LNG ships to deliver the product to receiving terminals in the US and southern Europe. Total investments for these new ships were approximately 5.4 million NOK, and it was calculated that 70 cargos of LNG per year would be shipped from the Melkøya facility to the international market. These cargoes were initially intended for the US East Coast, but Snøhvit's owners had to improvise because of an oversupply of natural gas in the US market. The reality has become that some of the LNG has gone to Europe and some to the Asian market (Lee, 2013a). This demonstrates the importance of LNG and its flexibility in changing economic environments.

3 NATURAL GAS MARKETS

Shift in the dynamics of the natural gas market is a complex matter. In this chapter we are going to explain the various factors affecting the natural gas price and the spot market. We are also going to explain how the regional prices emerged and the events behind.

3.1 FACTORS AFFECTING NATURAL GAS PRICES

Just as other energy commodities, natural gas prices are a function of supply and demand (EIA, 2013a). Electricity generated using natural gas is considered to be swing-capacity. This means that it is used to stabilize peak demands that the base load does not handle. The base load delivers power around-the-clock, i.e. all hours of the day. During hot summers the demand for air conditioning is high, in turn, increasing the power sector’s demand for natural gas, which can increase prices. In addition, the capacity of gas-fired power plants is reduced by impeding the efficiency when the weather is hot (Lapuerta and Moselle, 2001). In cold periods residential and commercial end users consume natural gas for heating purposes, which places an upward pressure on prices as the demand increases. In other words, the different demand sectors for natural gas have their own intra-annual pattern. Even unexpected or severe weather, can in short periods intensify the price, because in the short run there are limited alternatives for natural gas consumption or production (EIA, 2013a).

The condition of the economy has a major influence on natural gas demand and prices. A period with economic growth leads to an increased demand for goods and services from commercial and industrial sectors using natural gas. Especially from the industrial sector, which is a leading consumer of natural gas, the demand for both plant fuel and feedstock for products such as fertilizer and pharmaceuticals leads to increased natural gas demand. Recessions or weak economic growth usually have the opposite effect (EIA, 2013a).

Logically, gas suppliers will seek to move LNG cargoes to markets where demand and price conditions provide a profitable opportunity to do so. The extent of this physical arbitrage is dependent on the correlation of such demand and price variations between the regional markets (Hayes, 2007). Flexible routing of LNG cargoes provides an alternative to meet demand variability. This means that diversion of LNG cargoes to respond to price increases would also be expected to reduce those price increases. As a result, diverting cargoes would likely reduce the non-correlated variation in prices between markets. LNG industry analysts have the common perception that LNG arbitrage will bring “the integration” of regional gas markets. The hypothesis is that the growth of LNG trade over time will yield inter-regional price relationships like oil or other globally traded commodities, with a tight price connection to the cost of transport between regions. In other words, the LNG market will become more efficient. Even though there has been an increased interregional trade, LNG flows are still just creating links between the regional markets, in which there are strong supply and demand dynamics (IGU, 2014).

In periods with lesser demand, natural gas is placed in storage and may be used to dampen the impact of high demand during cold weather or short-term increase from unexpected events. The gas can be held in underground storage fields (although more efficient in terms of volume, storage of natural gas in form of LNG is more expensive). There are two kinds of storage facilities for natural gas, each with their own purposes: meeting base load and peak load demands (NaturalGas.org, 2014a). The base load storages are used to meet the seasonal requirements, while peak load storages are insurances against unforeseen supply disruptions. Storage levels usually increase from April through October, when demand for natural gas is low, and decrease from November through March, when natural gas demand is high (EIA, 2013a).

The industrial consumers and electricity generation utility fleet can switch between natural gas, coal and oil, depending on their respective price. Because of the interrelationship between these fuels and their markets, any shift in demand from natural gas to coal or oil reduces natural gas prices. Increasing prices of a competing fuel, relative to natural gas prices, will result in increased natural gas use, and inevitably an increase in natural gas prices.

Natural gas has had a few eventful situations where the long-term historical level has appeared to be abandoned for much higher prices. Extreme weather, wars and changes in energy policy has created new and unexpected imbalances between the supply and demand, which has led to price movements. This is reflected in the volatility of natural gas prices. Natural gas has always exhibited high price volatility (Pilipovic, 2007). The limited number and cost of storage facilities, the regional structure of the gas market (which is yet to be as globally developed as the oil market), and its strong relationship with electricity (the most volatile commodity) could be some of the explanations. High historical volatility might imply that just anything could happen. In general, understanding this is crucial in risk management of natural gas.

3.2 Gas spot market

Since the world market for natural gas is fragmented into different regional markets, it is not possible to talk about a world price, in contrast to oil. In North America where the market is highly liberalized prices are very competitive, and is extremely respondent to demand and supply forces. In contrast, the Russian federation has a clear monopoly with domestic prices kept artificially low, while gas is sold in foreign markets at higher prices to cover the loses. In western continental Europe, as well as Japan, the prices are highly based on the competition with alternative fuels and mostly indexed on oil prices. In the UK the gas marked is liberalized and prices are defined by competitive mechanisms. The interconnector between Bacton (UK) and Zeebrugge (Belgium) brings a price formula for spot prices to the UK, which is closely related to the formula used for calculating the oil price. Natural gas prices in the market may be measured at different stages in the supply chain, starting with the wellhead price, and will reflect a number of components:

- Wellhead price (the cost of natural gas itself)
- Long-distance transportation cost
- Local distribution cost

The cost of transportation within Western Europe does not increase with distance, but with the number of zones crossed between the two end points. This is not the case over a certain distances because gas needs to be regularly re-pressurized in dedicated and costly stations. The major demand factors are weather and economic activity. Because of the importance of the weather factor, natural gas demand is highly seasonal, causing seasonal fluctuations in spot prices (Geman, 2005).

Figure 3.1: Overview of global spot price benchmarks in July 2013 (Timera Energy, 2013a).

Figure 3.1 illustrates the high price differences between regional markets, as seen in July 2013. We will now go in to the four major markets and explain the dynamics behind the price differences, and what caused the big difference in price between them.

3.3 The regional gas markets

3.3.1 North America

Natural gas has become one of North America's most important energy resources, especially after the shale gas revolution. The development of shale gas technology with horizontal drilling and hydraulic fracturing has had significant implications for the domestic supply, for natural gas prices and for the economy. The gas market is liberalized and operates with spot and futures trading, and with low regulations compared to the European market. As of today, natural gas prices remain relatively low compared to levels of the 2000-2010 periods. With sustained high North American natural gas production levels and modest economic growth there has been a stable natural gas supply and demand. In addition to this, there are continued high storage levels, which also contribute to regulation and stabilization of the domestic market (Thomas, 2013). But what has caused the price to drop as low as 3 USD/mmBtu? In order to explain the situation we have to look at the characteristics of the shale gas revolution.

Unconventional gas, compared to conventional gas, does not flow freely to the surface, and has to be forced up using injection of chemicals and fracking. This type of gas is more expensive to produce and require higher natural gas prices in order to break even (Engdahl, 2013). Further, there are very high decline rates of 65-85% within the first 12 months of production on unconventional wells. From the revolution in 1993 Barnett production wells grew from a modest 170 wells in 1993 to a little over 17000 wells at the end of 2013 (Reed, 2013). With high prices and no regulation, investment and development in technology continued to grow. This growth of supply and peeking storage volume as a consequence of overproduction (especially in the summer) has caused prices to drop down to today´s level (Bernman, 2013).

With large scale emergence of shale gas over the last years and no regulation in investments and supply, the downward pressure on North American natural gas prices are quite noticeable. The low prices, compared to the other markets, means that the US is in a good position to become a LNG exporter as they are moving towards energy self-sufficiency. North America has however very limited LNG exports capabilities, due to the fact that most of its infrastructure still reflects the assumptions of the 2000s; that they would become a major LNG importer. In addition, there are debates centered on the hands-off approach that the regulations of LNG exports would cause the domestic prices to skyrocket. As a result the North American market has been largely isolated from the rest of the world. Trading at the transparent Henry Hub for natural gas currently drives pricing, and the price level is around 5 USD/mmBtu (Platts, 2014).

3.3.2 Europe

Europe as a whole is the world´s largest importing market. However, the European Union (EU) is trying to achieve its 20-20-20-target, and as a result there has been a rising share of electricity generation from renewable energy sources, rather than fossil fuels, like natural gas. The displacement of gas has increased even further as there been a growth of coal and lignite usage, thus offsetting the emissions reduction made through renewables. Unfavorable market fundamentals have made the running hours of gas-driven power plants record low. Nonetheless, due to its low carbon dioxide content, growing supply diversity and the flexibility backing up renewables, gas remains an attractive energy option for Europe, says Beate Raabe, Secretary General of Eurogas (Eurogas, 2013a).

Most of the gas is coming to Europe by pipeline, but LNG supplies have an increasing share. In 2012 EU´s major external sources for natural gas were Russia (23%), Norway (19%) and Algeria (9%), where the two latter supplied Europe both through pipelines and LNG. Qatar delivered 6% of EU's gas imports, all as LNG (Eurogas, 2013b). The LNG imports into Europe decreased from 24% to 18% from 2011 to 2012 due to the strong competition for LNG in the global market, especially from Japan after the Fukushima incident.

The European natural gas market has historically been dominated by bilateral long-term takeoff trade agreements, which typically span in the 20+ years duration. In order to the get projects going, investments must have been made in both the production, transportation and the distribution side of the market (Booz and Company et al., 2013). With this type of contracts dominating the market, the gas price tends to follow substitute fuels, in this case oil. While the spot market is becoming increasingly important, the prevailing gas pricing model in Europe reflects oil price movements rather than actual demand and supply patterns. The European commission has pushed towards gas market liberalization throughout the past decades, but the markets still remains fragmentally defined by national borders and policies. Incumbent utility companies dominate these markets, where of which many are state owned and come with long-standing bilateral ties to external suppliers. However, as long-term contracts move towards the end of their lifetime, more actors in the market are seeing the benefit of spot trading. This could lead to a natural gas market that looks more like the US or the UK were hub pricing is used. The hub in the UK is called NBP (National Balancing Point) and is a virtual pricing and delivery point for ICE natural gas futures. EU's decision to embark towards de-carbonization and reduce greenhouse emissions is another factor that could benefit increased usage of natural gas and LNG

Currently projects and trends in European natural gas are to a large extent driven by policy choices and regulation, and to a smaller extent by price, at least compared to the US. The situation of existing contract structure may be too strong to fully integrate an independent spot market. The declining of natural gas production in Europe and spillover from the economic crisis in 2008, combined with the shale gas revolution in the US, has caused an increase in natural gas prices. A snapshot from imports to Germany shows that long-term contracts trailed at 12 USD/mmBtu, much higher than US price levels of around 5 USD/mmBtu (European Commission, 2013).

3.3.3 ASIA

The Asian market is the fastest-growing gas market worldwide, and Japan is the world´s largest importer of LNG. The natural gas market is dominated by long-term contracts, typically signed at a substantial premium to US and European hubs. The prices are highly indexed to the price of oil. The long-term contracts have been popular in emerging economies because of security of supply. In Japan there was a significant increase in LNG import after the Fukushima Daiichi nuclear disaster in March 2011. By shutting down their nuclear reactors they had to increase the LNG import in order to meet their energy consumption. In a market with already high LNG import prices, the volume demanded by Japan has caused a large negative economic impact and trade deficit for the country. The increase in LNG import cost is imposing stress on the Japanese people and energy intensive industries due to high fuel costs (Japan. Ministry of Economy, Trade and Industry 2013).

In regards to regulation and control, the Japanese government is involved in both upstream and downstream through state owned companies. Due to this vertically integrated structure, separation of transport and commercial activities is difficult. If we compare the price level in the US at around 5 USD/mmBtu with Japan´s at just short of 20 USD/mmBtu, the difference is massive (Platts, 2014). The main reasons for this lies in the noticeable events, such as the shale gas revolution and the Fukushima incident. Another big reason is the uncompetitive energy market that protects local monopolies (Stern, 2013). Japan's electricity and gas companies provide long-term contracts for their consumers, because it is a good business model for local monopolies and regulatory structures. The Japanese have an uncompetitive national/regional market and their governmental regulations are affecting price deregulation at the wholesale level.

With Japan's energy deficit they are very dependent on LNG imports. The price in this region will continue to stay high because of it, but the question is for how long. Three years after the incident there less than one third of the country's nuclear reactors can satisfy the security protocols to start up again. Of Japan 54 nuclear plant, only 14 would probably be online somewhere in the future, meaning that Japan will most certainly be dependent on LNG imports in the coming years (DN.no, 2014).

3.3.4 South America

The past two decades have brought dramatic swings to the Latin American natural gas and electricity integration. Investors and governments are more risk averse as the economic and political drivers of cross-border investment and cooperation have evolved. The technological developments of shale gas in the US will be extended to Latin America and a renewed political momentum for regional economic cooperation and trade extends to the energy sector. After the energy integration euphoria of the late 1990´s the economic liberalization faded with more protective and less investment-friendly policies in many South American countries. Events such as the peso crisis in Argentina and cut-off of natural gas to Chile during the 2000s caused South Americans to question each other’s supply agreements (Bailey, 2013). The result was that the region turned to the global market, and in the latter half of the first decade of 2000, Brazil, Argentina and Chile built LNG terminals to meet their growing natural gas demands. Because of the shale gas technology there has been a growing potential for shale gas in Argentina, Brazil and Mexico. The region sees more flexible arrangements concerning LNG more likely to move forward than major cross-border pipelines. This is mostly because of political differences within the region, environmental concerns of shale gas and uncertainty around climate policies. Even with a well-developed LNG sector there is still an inability for countries to secure natural gas supplies. It is important to remember that these countries are developing countries and their growing energy demand is causing high prices for natural gas in this region.

4 METHODOLOGY

The purpose of this methodology chapter is to provide insight into how and why our study was conducted. The foundation for this study is our participation in a Master's program in Energy Management. The program has a strong focus on the oil, gas and energy sector. In this context, we chose to look at the value of investing in a LNGC.

Our main problem statement is: "*What is the increased value of investing in a ship selling LNG on spot instead of a long-term contract for a Norwegian producer?*" Based on our knowledge from our Master's program, we know that historically LNG carriers have been on long-term charters for 20-25 years. Recent demand shifts and the increased trade on the spot and short-term market led us thereby to further investigation.

In the initial phase of our research process we made a more specific overview of relevant literature and knowledge that could help us with the investigation. This part of the process consisted of searching up articles and recent publications both online and in compendia, as well as find literature available at the university library. This helped us get an outline of how the LNG value chain works, and especially trade and shipping of LNG. The main method to answer the research question is an investment analysis.

4.1 RESEARCH DESIGN

As a result of the thesis' research question we found it appropriate to use a quantitative approach. The reason for this was that we wanted to examine if there is an increased profitability of using a LNG carrier without long-term sales contract. To be able to investigate if and what the value difference of a free destination carrier and a long-term LNGC, we created different fictional cases. These cases would then be analyzed separately, and then compared to draw any conclusions. Each of the four cases was based on different assumptions and a sub research question, which ultimately would help us answer the main research question. In the gas market prices play a very important role. We therefore saw it suitable to forecast future prices. In addition, to supply the statistical forecast we did a strategic industry analysis, which also helped us evaluate whether or not an investment should take place. We will now go through the method used to forecast future prices, and most importantly, the investment analysis.

4.2 Forecasting

The predictability of an event or quantity depends on many factors, including: 1) the understanding of the factors that contribute to it. 2) The amount of data available. 3) Can the forecasts affect the "thing" being forecasted? A good forecasting model captures the way in which things change, even if the environment is changing. The latter is reasonable, because forecasts rarely assume that the environment is unchanging. What can, and normally is assumed, is that the way in which the environment is changing will remain in the future. This means that a highly volatile market probably will continue to be highly volatile, and that an economy that has had booms and busts probably will continue through these as well. The intention with a forecasting model is to define how things move, not just where they are.

A forecast will differ widely in their time horizons, factors determining actual outcomes, type of data patters, etc. Forecasting can be done with a number of methods, being very simple using the most recent observation, or highly complex such as neural nets and econometric systems of simultaneous equations. In cases where there is no data to work with, e.g. forecasting sales of a new product, judgmental analysis and forecasting is possible. Hence, the data available and the predictability of the quantity to be forecasted is the foundation for choice of method.

4.2.1 Determining what to forecast and what data to use

If used correctly, forecasting can be a valuable tool when integrated in decision-making activities and strategic planning. Depending on the appliance most organizations need short-, medium- and long-term forecasts. Decisions about what to forecast should be done in the early stages of such a project. It is also necessary to ask which regions, and whether weekly, monthly or annual data should be the output. In addition, what forecast horizon will be required? Depending on whether it is one month, half a year or ten years different types of models will be necessary. Once the kind of forecast needed has been determined, it is necessary to collect the data. Generally, there are two ways of collecting data: collecting own primary data, or use secondary data that has already been collected and stored within databases (Easterby-Smith, Thorpe and Jackson, 2012). The first gives the benefit of control and confidence that the data will match the study objectives. However, it could be time consuming and expensive, compared to using already existing secondary data. The disadvantage of the latter is that the quality of the data could be unclear.

4.2.2 Forecasting methods

The methods of forecasting can be divided in to two main groups: qualitative and quantitative. Qualitative forecasting, sometimes called judgmental forecasting, is used when there is no data available, or if the data available is not relevant to the forecasts. Quantitative method can be applied when numerical information about the past is available and it is reasonable that some characteristics of the historical patterns will continue into the future (Hyndman and Athanasopoulos, 2012). This approach has a wide range of methods that often are developed within specific disciplines for particular uses. The specific methods have their own properties, accuracies and costs that should be reflected upon before use. The data used is usually a time series (collected at regular time intervals over time) or cross-sectional data (collected at a single point of time) (Hyndman and Athanasopoulos, 2012). Qualitative and quantitative forecast can be combined, either by merging statistical and judgmental forecasts, or by adjusting the statistical forecast using judgment.

Cross-sectional models

A cross-sectional model is used when the variable to be forecasted exhibits a relationship with one or several predictor variables. The purpose of such an analysis is to describe the structure of the relationship and use it to forecast values of the forecast variable that have not been observed. Any change in the independent variable will affect the system output in a predictable way, assuming that the relationship does not change. Examples of this kind of modeling are regression models and additive models.

Time series

When forecasting using time series the aim is to approximate how the sequence of observations will persist in the future. Just as regression and additive models, a time series forecast can capture seasonal and/or trend patterns seen in the historical data and replicate it for future years (Hyndman and Athanasopoulos, 2012). However, time series forecasting only use information on the variable to be forecasted, and does not estimate the factors which affect its behavior. Time series models include ARIMA models, exponential smoothing and structural models.

Predictor variables in time series forecasting

Time series forecasting can also include independent variables. Using only these variables, the daily natural gas price (NGP) could be described as:

$$NGP = f(economy\ strenght, temperature, storage\ levels, month, error)$$

Yet, there will always be changes in the natural gas price that cannot be explained by the predictor variables. The function also includes the term "error", which allows for random variation and the effects of possible relevant variables that are not included. Since natural gas price data are in the form of a time series, the forecasting equation could be in the form of:

$$NGP_{t+1} = f(NGP_t, NGP_{t-1}, NGP_{t-2}, NGP_{t-3}, \dots, error)$$

Here the function is based on different days, and the prediction is only based on past values of the variable. Error is also included to account for the random variations not included in the model. Dynamic regression models, panel data models or longitudinal models are examples of the combination of these two models, and could look like this:

$$NGP_{t+1} = f(NGP_t, temperature, storage\ levels, month, error)$$

Explanatory models using independent variables could be very useful because it incorporates information about other variables, rather than only the historical values of the variable to be forecasted. According to Hyndman and Athanasopoulos (2012) there could be several reasons to choose a time series model over an explanatory model. Foremost, the system may not be understood completely. Even if it was, it could be very difficult and time consuming to measure the relationships that are assumed to control the dependent variable. Secondly, in order to forecast the variable of interest it is necessary to know or forecast the different predictors, and this could be extremely difficult. Thirdly, the main goal could be to only forecast the variable of interest, not to know why it happens. Lastly, a time series model could give more precise forecasts than an explanatory or mixed model.

4.2.3 The basic steps of forecasting

Hyndman and Athanasopoulos (2012) list five basic steps in the process of forecasting:

Step 1: Problem definition

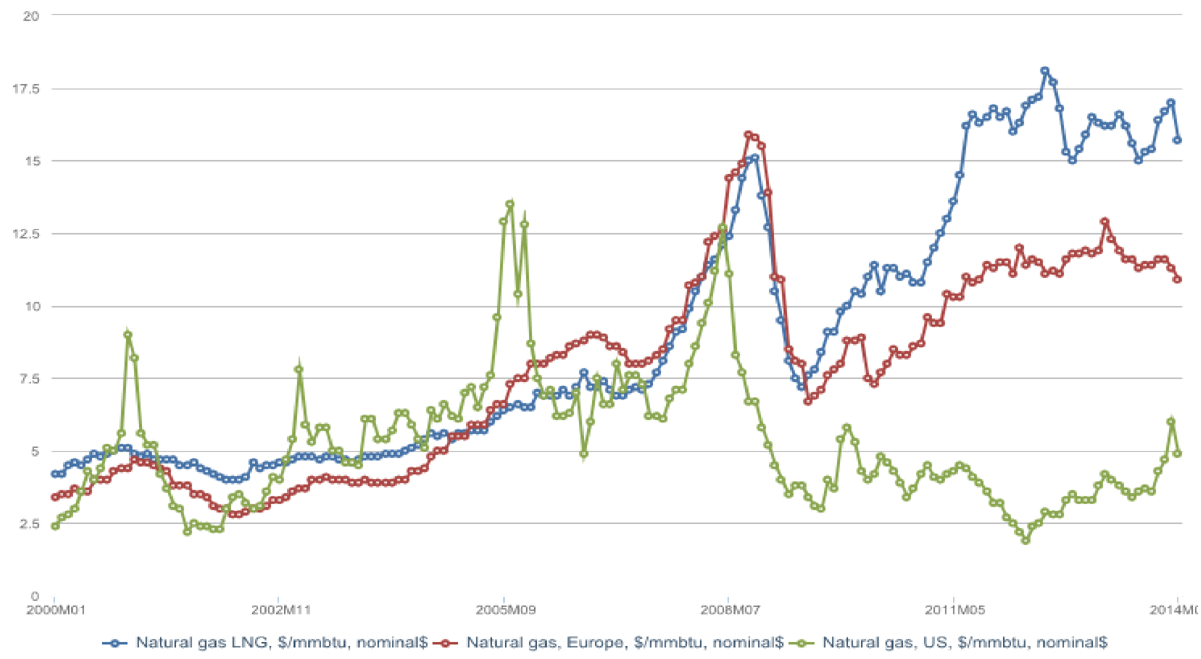
Defining the problem is often the most difficult part of forecasting because it requires an understanding of the way the forecast is to be used and who is going to use it. In this thesis the forecasts will be future natural gas/LNG prices, and will be used as input in a valuation analysis. This is the only purpose, meaning that a time series model will be used to forecast. To reflect the cases created on the basis of the sub-research questions, the relevant future prices are in UK and Japan. To test the sensitivity of the investment analysis we will create three different price scenarios. These will be based on the statistical forecast, and judgmental forecasting based on a strategic industry analysis.

Step 2: Gathering information

The information required will be separated into at least two types: (a) statistical data, and (b) the accumulated expertise of the people who collected the data and use the forecasts. In the strategic industry analysis we collected information type “b”.

A common approach is to use the historical data to determine which pricing model is appropriate and to assign parameters for simulating future prices. This assumes that the fundamental characteristics of markets are constant over time. It is often challenging to attain enough historical data to fit a good statistical model. Yet, very old data will be less useful due to changes in the system being forecasted. In our case the availability of historical data was somewhat limited. Although the data was more than sufficient in terms of the years going back, only monthly averages was publically available. The source of the historical prices was the Global Economic Monitor (GEM) Commodities (The World Bank, 2014). The prices in Japan are monthly average estimates based on the LNG import Cost Insurance and Freight (CIF). The price in Europe is based on average import border prices. However, a spot price component from NBP was only included from April 2010. The lack of more specific data makes this a simplified representation of the European market, as it is consists of many more pricing points or hubs. Nonetheless, this generalization makes it possible to compare this regional market to other regional markets, i.e. Japan, where the pricing data also is based on an average. For simplification, the future prices for Europe will represent the local price at the delivery point defined in Case 2. Similarly, the future price in Japan will also represent the local price at the defined delivery point defined in Case 3. Case 4 will use a combination of these future prices.

The natural gas price time series show some major disturbances in the recent years. The increased growth of LNG imports and major changes to market conditions suggests that very old data may not provide a reliable predictor for future price behavior. This is visible from the major price movements for all three regional markets illustrated in Figure 6.1. Prior to the 1990’s natural gas prices moved very fragmented, and was highly reflected by the use of pipelines and no flexibility. Since the year 2000, LNG as a natural gas source has been growing steadily (IGU, 2014). To account for these changes, while using the greatest number of observations, the natural gas price data starts in year 2000 until the most recent observation, April 2014.



Country : World
Created from: Global Economic Monitor (GEM) Commodities
Created on: 04/09/2014

Figure 4.1: Natural gas prices, USD/mmBtu over the period of January 2000 to February 2014 (The World Bank, 2014)

In accordance with the data series available, it is assumed that the choice of the market for LNG shipments is updated on a monthly basis. Although this might be a simplifying assumption, as it removes a lot of the variance and could be misleading, it is not unreasonable because it provides a lower bound (between daily and monthly data series) for the value of destination flexibility. Since it takes some time to schedule a LNG shipment (both laden and ballast - a round trip from Norway to Japan takes over 40 days), it is very difficult to profit from very short-term arbitrage opportunities such as daily or weekly price data. Using monthly price movements could enable capturing of seasonal effects of the markets. The share of spot trade in the LNG market is not significant, but increasing. This leads us to the possibility of seasonal market switching between the European and Japan market. In addition, there could be a possibility to take advantage of arbitrage opportunities on a monthly basis.

The US market is fairly close to the Central and Southern American, where the price is significantly higher. However, the possibility of arbitrage from buying LNG in the US and selling to these or other markets is not considered. The reason for this is the US energy policy keeping exports low and thereby maintaining low energy prices domestically. Therefore, the US market as an alternative, has not been used in any of the cases. In addition, this thesis is limited to the standpoint of a Norwegian producer's. Lastly, to refine our focus further the South American market is not included in any of the cases.

Step 3: Preliminary (exploratory) analysis

This step involves presenting the data in an informative way, e.g. graphics. Further, analyze the data by looking for consistent patterns, seasonality, business cycles, and outliers. The tool used for this step was R, a software environment for statistical computing and graphics. R was also used for fitting a model and forecasting future prices. A lot of the time used in the preliminary analysis was used to explore and learn the computing language and the functions of the program.

For the price scenarios based on judgmental forecasting, the preliminary analysis was combined with a strategic analysis. This strategic analysis was used as a foundation to argue whether or not an investment in the LNG industry is valuable.

Step 4: Choosing and fitting model

The higher number of observations, the greater chance we have of getting a reliable forecast. However, using merely 13 years of monthly data to forecast future prices in the lifetime of a LNG carrier could in many ways be considered a wild guess. The thing being forecasted is unknown, or it would not be necessary to forecast it, and could be regarded as a random variable. The future monthly natural gas price could take a range of possible values, and until the month is over and an average is estimated, the value is unknown. Because the next month is relatively close it is possible to give a reasonable forecast estimate. In most situations the variation associated with the variable will shrink as the event approaches. This means that the further into the future a variable is to be forecasted, the more uncertainty it will have. Given the data we had available, and the flexibility of fitting it, we chose to use an ARIMA model for each of the two time series.

Step 5: Applying and evaluating a forecasting model

After estimating model parameters, the model can be used to make forecasts. A forecast will always only be an estimate, with increasingly broader prediction intervals. The forecast itself will be the middle of the range of possible values the random variable could take. In most cases, a forecast is accompanied with a prediction interval giving the range of values the random variable could take with relatively high probability. For example, the 95% prediction interval will contain the range of values, which should include the actual future value with 95% probability.

The evaluations of the forecasting models were based on the assumptions taken when fitting them. Mainly this involved analyzing the residuals, i.e. the error not explained by the model. How an ARIMA model is estimated will be explained in the following sections.

4.2.4 Forecasting tools

Autoregressive model

The term autoregression indicates that it is a regression of the variable against itself. With an autoregression model we can forecast the variable of interest using linear combination of past values of the variable. Accordingly, an autoregressive model of order p can be written as:

$$y_t = c + \phi_1 y_{t-1} + \phi_2 y_{t-2} + \cdots + \phi_p y_{t-p} + e_t$$

Where c is a constant and e_t is white noise. The autoregression is almost like a multiple regression, but with lagged values of y_t as predictors, and is referred to as an AR(p) model. The benefit of Autoregression models is that they are flexible at handling a wide range of different time series patterns.

Changing the parameters $\phi_1, \dots, \phi_p$ result in different time series patterns. The variance of the error term e_t will however only change the scale of the series, not the patterns (Hyndman and Athanasopoulos, 2012).

For the AR(1) model it is important to remember that:

- When $\phi_1 = 0$, y_t is equivalent to white noise
- When $\phi_1 = 1$ and $c = 0$, y_t is equivalent to a random walk
- When $\phi_1 = 1$ and $c \neq 0$, y_t is equivalent to a random walk with drift
- When $\phi_1 < 0$, y_t tends to oscillate between positive and negative values

Some constraints on the values of the parameters are required since autoregressive models are normally restricted to stationary data:

- For an AR(1) model: $-1 < \phi_1 < 1$
- For an AR(2) model: $-1 < \phi_2 < 1$, $\phi_1 + \phi_2 < 1$, $\phi_2 - \phi_1 < 1$.

If $p \geq 3$ the restrictions are much more complicated. R takes care of these restrictions when estimating a model.

Moving average models

A moving average model uses past forecast errors in a regression-like model, rather than use past values of the forecast variables in a regression. This model is referred to as an MA(q) model, where e_t is the white noise and, are used for forecasting future values.

$$y_t = c + e_t + \theta_1 e_{t-1} + \theta_2 e_{t-2} + \cdots + \theta_q e_{t-q}$$

The values of e_t is not observed, so it is not really regression in the usual sense. Although each value of y_t can be thought of as a weighted moving average of the past few forecast errors, it should not be confused with moving average smoothing. Moving average models are used for forecasting future values, while moving average smoothing are used for estimating trend cycles of past values (Hyndman and Athanasopoulos, 2012).

Changing the parameters $\theta_1, \ldots, \theta_p$result in different time series patterns. Just as with autoregression models, the variance of the error term $e_t$will only change the scale, not the patterns.

There is a possibility of writing any AR(p) model as an MA(∞) model. We can demonstrate this for an AR(1) model, using repeated substitution as an example:

$$
\begin{aligned}
y_t &= \phi_1 y_t + e_t \\
&= \phi_1(\phi_1 y_{t-2} + e_{t-1}) + e_t \\
&= \phi_1^2 y_{t-2} + \phi_1 e_{t-1} + e_t \\
&= \phi_1^3 y_{t-3} + \phi_1^2 y_{t-2} + \phi_1 e_{t-1} + e_t \\
&\; etc.
\end{aligned}
$$

Given that $-1 < \phi_1 < 1$, the value of ϕ_1^k will get smaller as k gets larger. So eventually we obtain an MA(∞) process:

$$y_t = e_t + \phi_1 e_{t-1} + \phi_1^2 e_{t-2} + \phi_1^3 e_{t-3} + \ldots,$$

If we impose some constraints on the MA parameters, the reverse result holds and the MA model is invertible. Then we can write any invertible MA(q) process as an AR(∞) process. Invertible models are not simply for enabling us to convert MA to AR models. Some of their mathematical properties also make them easier to use in practice.

Invertible constraints are similar to the stationary constraints.

- For an MA(1) model: $-1 < \theta_1 < 1$.
- For an MA(2) model: $-1 < \theta_2 < 1, \; \theta_2 + \theta_1 > -1, \; \theta_1 - \theta_2 < 1$

ARIMA models

ARIMA models can be used with both non-seasonal and seasonal data. To obtain an ARIMA model (non-seasonal), we combine the differencing with autoregression and a moving average model. ARIMA stands for Autoregressive Integrated Moving Average model (integration in this context is the reverse of differencing). This model can be written as:

$$y'_t = c + \phi_1 y'_{t-1} + \cdots + \phi_1 y'_{t-p} + \theta_1 e_{t-1} + \cdots + \theta_q e_{t-q} + e_t$$

In this model y'_t is the differenced series, and it may have been differenced more than once. The predictors on the RHS include both lagged values of y_t and lagged errors. This is called an ARIMA(p,d,q) model, where:

p = autoregressive order

d = degree of first differencing involved

q = moving average order

The stationarity and invertibility conditions used for autoregressive and moving average models, also apply to this ARIMA model.

When we combine the components we can form a more complicated model, which is much easier to work with the backshift notation. Then the equation can be written as:

$$\underbrace{(1 - \phi_1 B - \cdots - \phi_p B^p)}_{\uparrow \atop \text{AR(p)}} \quad \underbrace{(1 - B)^d y_t}_{\uparrow \atop d \text{ differences}} \quad = \quad \underbrace{c + (1 + \theta_1 B + \cdots + \theta_q B^q) e_t}_{\uparrow \atop \text{MA(q)}}$$

It is usually not possible to tell the order of the ARIMA model simply by looking at a time plot. Tools like ACF and PACF plots can be helpful to select the appropriate values for p, d and q. In addition, the function auto.arima() in R does this automatically. However, in most cases the best solution is to combine the two, and then check some variations of the model/s suggested by ACF/PACF plots and the auto.arima()-function (Hyndman and Athanasopoulos, 2012).

A seasonal ARIMA model includes additional seasonal terms in the non-seasonal ARIMA model. It can be written as follows:

$$ARIMA\ (p, d, q)(P, D, Q)_m$$

Where $(P, D, Q)_m$ is the additional seasonal part, and m is the number of periods per season. The seasonal part use AR and MA terms to predict y_t using data values and errors at times with lags that are multiplied with m.

White noise

Time series showing non-autocorrelation are called white noise. White noise refers to serially uncorrelated random variables with zero mean and finite variance. White noise ACF spikes are expected to lie within 95% significance bounds. These bounds are common to plot. If there are one or several large spikes outside these bounds the series is not likely white noise.

Autocorrelation

In the same way correlation measures the scope of a linear relationship between two variables, autocorrelation measures the linear relationship between lagged values of a time series (Hyndman and Athanasopoulos, 2012). The different coefficients of autocorrelation depend on the lag length, e.g. r_k measures the relationship between y_t and y_{t-k}. The value of r_k can be written as:

$$r_k = \frac{\sum_{t=k+1}^{T}(y_t - \bar{y})(y_{t-k} - \bar{y})}{\sum_{t=1}^{T}(y_t - \bar{y})^2}$$

Where T is the length of the time series.

Plots of the autocorrelation coefficients form the autocorrelation function (ACF), this is also known as a correlogram.

Partial autocorrelation

If y_t and y_{t-1} are correlated, then y_{t-1} and y_{t-2} are also correlated. It would then seem like y_t and y_{t-2} are correlated in some way, just because they are both connected to y_{t-1}. To measure this relationship between y_t and y_{t-k} after removing the effects of other time lags: $1, 2, 3, \dots, k-1$, we can use the partial autocorrelations. The plot of these partial autocorrelations is called PACF. The first part partial autocorrelation is identical to the first autocorrelation, simply because there is nothing between them to remove. The partial autocorrelations for the following lags can be calculated as:

$$\begin{aligned}\alpha_k &= k\text{th partial autocorrelation coefficient} \\ &= \text{the estimate of } \phi_k \text{ in the autoregression model}\end{aligned}$$

$$y_t = c + \phi_1 y_{t-1} + \phi_2 y_{t-2} + \cdots + \phi_p y_{t-p} + e_t$$

Changing the number of terms on the RHS of this autoregression model gives α_k for different values of k.

Portmanteau tests for autocorrelation

The Ljung-Box statistic was proposed by Ljung and Box (1978). It is also known as a modified Box-Pierce statistic, and is a function of the accumulated sample autocorrelations, r_k, up to any specific time lag of h. As a function of h, we get the following formula:

$$Q(h) = T(T+2)\sum_{k=1}^{h}\frac{r_k^2}{n-k}$$

where T is the length of the time series.

This statistic can be used to examine residuals from a time series model to see if all the underlying population autocorrelations for the errors may be 0. For nearly all models, which we consider, the residuals are assumed to be white noise, implying that they are identically, independently distributed from each other. This means that the ideal ACF for residuals is that all autocorrelations are 0. Further this implies that $Q(h)$ should be 0 for any lag of h. With a significant $Q(h)$ for residuals, indicates that it may be a possible problem with the model.

Two cases of $Q(h)$ distribution:

1. When r_k are sample autocorrelations for residuals in a time series model, the null hypothesis distribution of $Q(h)$ is approximately a x^2 distribution with df = h – p, where p = the number of coefficients in the model.
2. When no model is implemented, so that the ACF is for raw data, p = 0 and the null distribution of $Q(h)$ is approximately a x^2 distribution with df = h.

A p-value, in both cases, is calculated as the probability past $Q(h)$ in the relevant distribution. A small p-value indicates the possibility of non-zero autocorrelation within the first h lags. In other words, a large p-value is not evidence of independence, simply a lack of evidence of independence.

To ensure that the number of lags is large enough to capture any meaningful and troublesome correlations, Hyndman's (2014a) rule of thumb is used:

- For non-seasonal time series, use $h = min(10, T/5)$.
- For seasonal time series, use $h = min(2m, T/5)$.

Power transformations

Heteroskedasticity can be a problem when fitting an ARIMA model to a time series. Such non-stationarity in variance, even after differencing, can be removed by transformations. Box-Cox transformations are a family of transformations that includes logarithms and power transformations (Hyndman and Athanasopoulos, 2012). The original observations are denoted as $y_1, \ldots, y_t$ and the transformed observations as $w_1, \ldots, w_t$, then $w_t = log(y_t)$. A useful feature of logarithmic transformations is that they constrain forecasts to stay positive. Examples of power transformations are square roots and cube roots, and can be written as $w_t = y_t^p$. Which transformation to use in the Box-Cox family depends on the parameter λ, and are defined as follows:

$$w_t = \begin{cases} \log(y_t) \; if \; \lambda = 0 \\ \dfrac{y_t^\lambda - 1}{\lambda} \; if \; \lambda \neq 0 \end{cases}$$

Back-transformation

The reverse back-transformation is given by:

$$y_t = \begin{cases} \exp(w_t) \; if \; \lambda = 0 \\ (\lambda \mathrm{w}_t + 1)^{1/\lambda} \; if \; \lambda \neq 0 \end{cases}$$

Transformations usually make little difference to the forecasts, but have a large effect on the prediction intervals. The approach preserves the probability coverage, although it will no longer be symmetric around the point forecast.

Akaike's Information Criterion (AIC)

AIC is a useful model selection tool, based on a penalized likelihood. Hence, it requires the likelihood to be maximized before it can be calculated. It can be defined as:

$$AIC = N \log\left(\frac{SSE}{N}\right) + 2(k + 2)$$

Where N is the number of observations used for the estimation and k is the number of predictors in the model. The model that gives the lowest value of AIC is usually the best model for forecasting. However, AIC from, for example an ARIMA model and an ETS model, cannot be compared (Hyndman, 2014a).

Corrected Akaike's Information Criterion (AICc)

AICc is a bias-corrected version of the AIC, as the AIC tends to select too many predictors when N is small. AICc should also be minimized.

$$AIC_c = N \log\left(\frac{SSE}{N}\right) + \frac{2(k+2)(k+3)}{N-k-3}$$

4.3 Investment analysis tools

In order to evaluate whether an investment should be take place or not, valuation tools are necessary. Choosing the right valuation tools is an important part of financial decision making. An investment holds factors that are uncertain, which may include prices, demand, costs, technology and other known and unknown factors. In order to cope with these factors we manage the risks involved in the investment with measurable valuation tools.

In the investment analysis we had taken into account prices forecasted, presented in three different scenarios, and costs relevant from similar shipping operations.

4.3.1 Discounted cash flow valuation

Discounted cash flow (DCF) is used in capital budgeting to analyze the profitability of an investment or project (Brennan and Schwartz, 1986). DCF-analysis can be divided into two main categories, the net present value method (NPV) and the internal rate of return method (IRR). The two methods have many similarities, but also some differences.

NPV

The aim of profit maximizing companies is to take on investments with positive net present value (NPV) to create shareholder value. It involves a comparison between the costs of the project, and the present value of the cash flows generated by the project, which is calculated according to this formula:

$$NPV = -CF_0 + \sum_{t=1}^{n} \frac{CF_t}{(1+r)^t}$$

In this model CF_t is the cash flow expected in the period and $(1+r)^t$ is the appropriate discount rate in the period. To calculate expected NPV, future cash flows must be forecasted. In addition, we have a third factor in the NPV formula, CF_0, which is the initial investment value of the project. The output of the equation is an NPV figure, telling decision makers what the project is worth at the date of the analysis. Projects with a positive NPV generates more money than they cost and should be undertaken, while projects with a negative NPV generate less money than they cost and should obviously not be undertaken from a financial point of view. Even though a project generates a positive NPV, companies should be careful with investments that have high CAPEX and OPEX and only marginally positive NPVs.

WACC

When determining discount rates, many companies start with the company cost of capital, which is a calculation of a company's cost of capital where each category of capital is proportionately weighted. This measure is called the weighted average cost of capital (WACC). If a project is considered to be equally as risky as the company's existing business, the cash flow projects may be discounted by WACC, and is calculated with this formula:

$$WACC_{company} = \frac{Debt}{Equity + Debt}\, R_{Debt} + \frac{Equity}{Equity + Debt}\, R_{Equity}$$

In this model R_{Debt} is interest rate the company pays for their debt. The two fractions in the formula represent debt and equity ratios. The last part of the formula is R_{Equity}, which is the cost of equity.

In order to calculate the cost of equity many companies use the Capital Asset Pricing Model (CAPM). When investing in new projects the companies need to consider two types of risk, unsystematic and systematic risk. Unsystematic risk represents company or industry specific risk, and can be removed by diversifying investments in different markets, creating a diversified portfolio (Bodie, Kane and Marcus, 2011). Systematic risk is associated with risks that affect the entire economy, such as wars, recessions and disasters. This type of risk cannot be avoided through diversification. CAPM is a model, which describes the relationship between risk and expected return of the investment, and is calculated through the following formula:

$$R_{Equity} = R_f + \beta_{Equity} \left(R_{Market} - R_f\right)$$

In this formula R_f is the risk free interest rate and is the rate received from investing in securities considered to have no credit risk. Examples of this are government bonds and bank deposits. R_{Equity} represents the compensations that the market demands for owning the asset and bearing the risk of that ownership. The systematic risk is represented through β_{Equity}, and is a measure of the volatility of the company’s share, compared to the market as a whole. If the beta is above or below one, the shares of the company move more or less than the market (Bodie, Kane and Marcus, 2011). The last part of the formula is $\left(R_{Market} - R_f\right)$, and represents the market risk premium. This figure is the difference between the expected return on a market portfolio and the risk-free rate.

IRR

An IRR analysis output is the projects IRR, and is defined as the discount rate, which makes NPV equal to 0. In general, the higher a projects IRR, the more desirable it is to undertake the project. Finding a project IRR can be done through this formula:

$$NPV = CF_0 + \frac{CF_1}{1+IRR} + \frac{CF_2}{(1+IRR)^2} + \cdots + \frac{CF_T}{(1+IRR)^T} = 0$$

Pros of DCF-analysis

The DCF-analysis is well known in financial theory with many applications, especially in valuation. It contributes to the decision making process, by providing a systematic and logic framework for an investment. The analysis takes costs, revenues, the issue of time and risk into its valuation. It does not only encourage investors to analyze all the relevant factors, but also to realize the importance of each factor and possible outcomes of different factors and scenarios.

Cons of DCF-analysis

The DCF-analysis often ignores how inflation will affect the various cash flows in the project. A proper analysis requires an understanding of inflation adjustment patterns for different cash flow segments (Hodder and Riggs, 1985). By not including inflation in an analysis, undervaluation of future cash flows may occur, resulting in not undertaking profitable projects. With positive inflation rate, the gap between projected cash flows and their nominal value grows over time. In oil and gas projects, price development, OPEX, CAPEX and other factors are subjected to inflation, so it would be a lack of consistency if future cash flows were not adjusted for inflation. Real cash flows should be discounted at a real rate, and can be calculated through this formula:

$$r_{real} = \frac{(1 + r_{nominal})}{(1 + Inflation)} - 1$$

The DCF-analysis and its failure to acknowledge how project risk can be reduced by diversification, is an issue when looking at isolated projects (Hodder and Riggs, 1985). By not diversifying a portfolio the expected return is higher for an investor because of the higher risk associated with it. Financial theory weighs the importance of a projects total risk, consisting of unsystematic and systematic risks, which are respectively diversifiable and nondiversifiable. A project diversified in different segments of the market may seem less risky than an isolated project's DCF-valuation. By looking at isolated projects the analysis may only evaluate the factors concerning the project. If these factors are evaluated using strategic reasoning the valuation becomes much more robust.

This drawback of the DCF-analysis has contributed to the development of the real option valuation, where the decision maker has the right but not the obligation to buy or sell an asset. In this thesis we are researching the increased value of a using an LNG carrier on free destination, and not the option of investing or not. Weather the investment takes place or not is irrelevant, since we are only interested in the value. Hence, the DCF method is used to evaluate the investment.

4.4 Reliability

The reliability of the data obtained is affected by the collector's ability to understand and present it properly, and the ultimate goal is to reduce errors and bias in the study. (Johannessen, Christoffersen & Tufte, 2011). The purpose of checking for reliability is to make sure that other researchers will produce the same results if this research is repeated later on. As this is mainly a quantitative study it would not be complicated to generate the same results. However, a requirement for this is that the same methodology and assumptions are used. By using quantitative measures like IRR and NPV we have two assessment tools that can measure value, and thereby increasing the reliability of this study. Although these measures are very objective, the assumptions used are somewhat subjective. For example, the method for determining the cost of equity is based on the Capital Asset Pricing Model, which parameters cannot be estimated precisely. Firstly, one would have to define a market index, and even if the beta is estimated from a regression, it would be based on subjective inputs, e.g. time series length, and whether to use daily, monthly, quarterly, etc. data. Secondly, there could be some changes to the firm during the estimation period. If later investigators change some of the basic inputs like fuel consumption, loading and discharging ports, fuel type, and other voyage specific costs, the output will not match the findings of this thesis. Hence, if a similar study uses the same methods and data it would most likely reproduce the results.

4.5 VALIDITY

Even though reliability is important in a study, it also needs to be valid. The validity of a research can be divided into internal and external validity (Easterby-Smith, Thorpe and Jackson, 2012). The internal validity of this research is the extent of which the findings provide an accurate representation of the thing to be described. The use of quantitative method and a systematic approach to the analyses makes us confident that the results are true and that the conclusions are correct. The interpretation of value under certainty is fairly easy. However, when there is uncertainty the interpretation is more problematic. It is expected that the value of spot and forward trade is highly affected by the market price. Therefore, using the appropriate data to forecast prices is of high importance. We chose monthly averages of European and Japanese prices. Even though the future prices estimated from our Europe data could be considered as a representation of Europe as a whole, the shipping distances in Europe is highly voyage specific. In addition, we have no way of knowing how these averages were estimated, and its weighting. As a consequence we decided to shorten the European natural gas prices, making it start in April 2010, when NBP spot prices were included. We believe that this smaller sample represents the natural gas price characteristics after the financial crisis and increased spot trade. The precision weakened and bias reduced, making the forecast more imprecisely right. Maybe if we had been able to get monthly averages from a specific delivery point or hub the accuracy of the forecast and the valuation analysis would have increased somewhat, while keeping bias low. Still, these forecasts were combined with judgmental analysis of the LNG industry to create three different price scenarios. By applying these price scenarios we can with a higher degree of certainty determine the value of the investment, given certain prices.

The external validity of this research is whether the results we have reached can be generalized to other settings. The LNG market is considered a bullish energy market, and the characteristics of such a market are probably not found in other energy markets. Therefore, it is not likely that such a value differentiation would occur in for example the oil market.

5 Presentation of the cases

Here we will present the cases used in the investment analysis. Every case will have its delivery point from the Melkøya plant in Hammerfest.

5.1 Case 1 – Forward contract to Milford Haven, UK

As mentioned earlier, the LNG from the Snøhvit field was originally intended towards the US East Cost. However, the shale gas revolution made it unprofitable to ship LNG to the US. 95% of Norway's natural gas infrastructure is tied up in pipelines to the North Western Europe, which makes Norway highly exposed towards market risk (Halmø, 2013). Long-term contracts have historically been a necessity to develop costly infrastructure. Today, around 70% of the total LNG sales are based on long-term contracts. To reflect this, the first case will consist of 100% risk management control through a forward contract with a buyer located at Milford Haven in the UK.

> A forward contract gives the owner the right and the obligation to buy a specified asset on a specified date at a specified price. The seller of the contract has the right and the obligation to sell the asset on the date for that specified price (Miller and Dubofsky, 2003).

As described above, a forward contract provides the opportunity to purchase a specific quantity at agreed price, with delivery in the future. The price of a forward contract is set so that the value is basically the same for both parties. Whether or not the contract turns out to be profitable for one of the parties depends on how the market fluctuates. If 100% available transportation offered by the new LNGC is tied up to a UK buyer, then there is no possibility of export towards other regional markets unless the contract is broken.

5.2 Case 2 – Spot sales to Milford Haven, UK

Every commodity is traded on a spot market. The transaction of a commodity may be physical, with delivery of the commodity, or financial, with a cash flow from one party to another at maturity with no exchange of underlying good. Physical and financial commodities are, as one may expect, strongly related (Geman, 2005). In order to isolate the economic value of selling towards an alternative market, we have a second case, where sales are 100% spot to buyers located at Milford Haven, UK.

5.3 Case 3 – Spot sales to Yokohama, Japan

In terms of potential price, the Japanese market is the most interesting market from a Norwegian supplier's point of view. To investigate the possibility of achieving the highest possible price, Case 3 is 100% spot sales to Japan. The buyers will be located in the port of Yokohama. In this third case there are two alternative transport routes. The first option is going through the Suez Canal, whereas the second is shipment via the Northern Sea Route (NSR).

The Northern Sea Route

The NSR is an international transit route that opened up for commercial transit in 2009. The route starts at the Novaya Zemlya Island in the West and ends at the Bering Strait in east, and introduces the possibility of quicker shipments through the new connection between Europe in the west, to Asia in the east. The reason for using the NSR as an alternative in the third case is the potential costs and time saved, compared to the traditional route through the Suez Canal. The Centre for High North Logistics (Gunnarsson, 2013) did a cost saving analysis with a round trip from Melkøya in Norway to Yokohama in Japan. The research showed that the cost saved from this trip was 6 854 000 USD, and time saved was almost 43 days. The availability of the NSR is not year round, due to winter and summer season changes. When the route is open, during the five months from July to November, it will be used in the Japanese spot case (Jones, 2013).

5.4 Case 4 – Spot sales to both UK and Japan

This fourth case will combine spot sales to both Milford Haven in UK and Yokohama in Japan. During the summer months the NSR will be used to sell LNG in Japan, while the rest of the year sales will be to UK. In that way we can investigate in the case comparisons if the

Japanese market really is that attractive. In addition, this would serve as a third option selling LNG on spot, as defined in the main research question.

6 STRATEGIC INDUSTRY ANALYSIS

In order to make proper investment decisions we have made an external and internal analysis of the barriers in the LNG sector using the PESTEL framework for external analysis and Porter's five forces for the internal analysis.

6.1 PESTEL

The first framework in this strategic analysis is at a macro level, and helps us assess the external environment of the LNG industry. A PESTEL analysis describes the macro-environmental factors and how it can impact the development of the industry and how it ultimately is influencing the value of the companies operating within it. By understanding the political, economic, social, technological, legal and environmental factors, one can better make strategic decisions in business environments with external influence (Murray-Vebster, 2010). With this analysis we are going to take a look at the pros and cons of the LNG macro-environment from a Norwegian point of view. We are excluding social and legal from the analysis because of their lack of impact and because they are approximately similarly for all companies operating in the industry.

6.1.1 POLITICAL

There has been a reduced demand for natural gas from the OECD-Europe during the last year (EIA, 2013b). If this continues, along with an unclear long-term energy policy in Europe, it could cause a reduction in the willingness to invest in gas production and infrastructure, according to senior advisor Ottar Skagen in Statoil (Tollaksen, 2013).

Analytics are predicting a long-term higher self-sufficiency of renewable energy in Europe after Russia's involvement in the Ukraine crisis, because of reduced confidence in Russia as a credible natural gas supplier. There are predictions about higher shale gas focus, causing lower natural gas prices in Europe in the long run. Even though Russia is as dependent on income from export as their customers are on natural gas, they have threatened with sanctions. (Tollaksen, 2013). This crisis however, puts Norway in a good perspective since they become more attractive as a stabile supplier of natural gas. Another key issue to keep in mind is that when Russia continually uses natural gas as a political weapon it reduces the reputation of gas, which is more serious in the long run.

Since natural gas consumption in Europe has gone down the last two years, this type of energy might be too unstable for the energy security in many European countries. There is a common understanding in political Europe to go for more renewable energy; it might reduce natural gas consumption as a major in the energy mix.

6.1.2 Economical

The Shale gas revolution has caused a drop in coal in the US, causing them to have an oversupply of coal, which they can sell cheaper to Europe. This entails a reduced consumption of natural gas in Europe with prices falling somewhat. Norway has tied 95% of their natural gas infrastructure to Europe, and is highly exposed to price volatility in the European market. With only 5% LNG available to export, Norwegian natural gas is very dependent on the European market. If this trend continues Norway could miss out on huge monetary values (Tollaksen, 2013). With reduced income from natural gas exports to Europe, Norway has to reconsider their co-dependence on Europe as a supplier. This is a selling point for investment in LNG, by increasing the flexibility and diversification it could reduce Norwegian market exposure. There are big opportunities in the Asian market post-Fukushima, and by giving more attention to the Asian market, Norway would as a supplier put more pressure on Europe making it a sellers' market. The NSR has become more available due to global warming, and this has opened up for possibilities for Norwegian supply towards Asia. The NSR offers as an alternative to going through the Suez Canal, and could mean potential savings of up to 7 million USD and 40 days for a round trip (Gunnarsson, 2013).

In Europe there is a LNG receiving capacity of less than 150 MTPA (IGU, 2014). According to Gas Infrastructure Europe (2014) there are 7 receiving terminals (27 MTPA) under construction and another 25 terminals (>120 MTPA) planned in the coming years. This demonstrates the further commitment towards LNG by Europe.

6.1.3 Technological

With increased interest in LNG, the technology race becomes an advantage for LNG operations. Technological improvements in all parts of the value chain are increasing the utilization of natural gas and making it more efficient and profitable.

The Fukushima incident has reduced confidence in nuclear energy technology, and has resulted in the out-phasing of nuclear power in Germany. This is beneficial for natural gas, as it has caused a higher demand, and thus, higher prices.

6.1.4 Environmental

Global warming has led to an increased attention towards reducing CO_2 emissions. The closest alternative energy source to natural gas is coal and oil. Both of those options lead to more pollution than natural gas (NaturalGas.org, 2014b). Therefore, natural gas is considered to be the best option compared to coal and oil. Political instruments and/or regulations may be used to turn the energy mix more towards more environmental friendly alternatives. However, coal-producing nations such as Poland are working against the EU and their goal to improve climate towards 2020. Meanwhile, carbon offsets decreased from 250 NOK to 60 NOK per ton CO_2 in 2012 (Tollaksen, 2013). As a result, the addition of cheap US coal in Europe has made natural gas demand suffer.

Global shipping industry has in recent years faced increasing limitations to sulfur emissions, thereby presenting LNG as a viable alternative maritime fuel. It contains close to none sulfur and its combustion produces low NO_x (mono-nitrogen oxides) compared to fuel oil and marine diesel oil (Gastechnology.org, 2014). It also has economic advantages. Even with high Asian LNG prices, it is still lower than global bunker fuel prices.

Higher LNG consumptions also offer environmental difficulties. Transportation of LNG is significantly more polluting than pipelines, because of the extra energy needed to liquefy and transport. As policymakers try to balance the promotion of energy security and the EU target of 20% reduction in greenhouse gases by 2020, this could become a barrier for LNG in Europe.

6.2 PORTER'S FIVE FORCES – INTERNAL ANALYSIS

The natural gas supply market is very complex, and in order to make good investment decision it is necessary to examine the basic competitive structure of the natural gas industry through the competitive forces around a Norwegian perspective. Before an investment in any industry, it's important to understand what forces determine the profits. For this purpose we decided to use porter's industry analysis framework. The model focuses on how five forces in an industry (competitive rivalry, suppliers, buyers, new entrants and substitutes) impacts and limits the profitability of the sector (Ahlstrom, and Bruton, 2010).

6.2.1 COMPETITIVE RIVALRY AND SUPPLY POWER

The reason for putting competitive rivalry and supply power in the same section is because we are looking at countries as a whole, both with focus on their supply capabilities and their competitive advantage/disadvantage in the LNG world market. Since the market is high in demand and prices, the competitiveness of the region depends on their ability to supply LNG.

North America

The reason for the low price for natural gas in domestic North America is as mentioned in 3.3.1, the shale gas revolution. With low prices domestic and high prices in other regional markets, especially Japan, LNG supply companies in the US have put pressure on the Obama administration to approve export of LNG to exploit regional price differences. But large inland users of natural gas, such as the petrochemical industry, are worried that exports could drive domestic prices up. A higher export rate and domestic use, compared to supply rate, could cause a supply deficit in the US, pushing prices up. There has been cases were the price for natural gas in the US has increased from 2 USD/mmBtu, breaking the 5 USD/mmBtu mark earlier this year, which has not happened since 2010 (Platts, 2014) Some analysts are blaming the cold weather, but according to natural gas analyst Bill Powers this has to do with fundamental changes in the US natural gas scene (Business News Network, 2014). As consequence of the oversupply from the shale gas revolution, low margins led to a decline in production rates and reduced drilling start-ups. Bill Powers further augmented that this could lead to another price incline, where the price could go up to 7 USD/mmBtu in the coming winter of 2014/2015 (Business News Network, 2014). This, combined with their currently limited LNG export capacity, limits and isolates the US market somewhat from the rest of the world in the short term.

Another key factor for US export of LNG is the cost of transportation, especially from the US Gulf Coast. However, there is optimism as the Panama Canal expansion project is approaching completion. This would mean a significant reduced sea voyage going from the US Gulf to Japan, from approximately 16 000 nm to about 9 500 nm going around Cape of Good Hope (Miles and Holmberg, 2014).

As of today the U.S. Department of Energy are only issuing export authorizations case by case. An important element is that the infrastructure still reflects the assumptions that the US were to become be a major LNG importer. The US invested billions of dollars making LNG import terminals, which also came with high political and environmental debate. If the Federal Energy Regulatory Commission and the U.S Department of Energy issues a green light for export across the country and allows licenses to transform the import terminals to export terminals the US could be a major supplier of LNG in the long term (Ebinger, 2014).

Russia

As production and export initiatives intensify in North America, Russia is moving towards strengthening their position as a natural gas exporter. In a response to the changing dynamics in the LNG market, President Vladimir Putin has also authorized LNG export licenses to other companies than Gazprom. The liberalization is a strategy designed to double Russian LNG market share in the long run. In addition to wanting a bigger part of the Asian market, Russia is exporting LNG to Spain also. Russia has a long relationship with Europe as a natural gas supplier through pipelines, and is entering the LNG race to secure a flexible position as a supplier. Gazprom is currently the world’s leading natural gas producer and operator of the LNG plant on the Sakhalin Island close to Japan. The company is also considering a new LNG plant in the Baltics to further target the European market. Russia is on both short and long-term outlook a big competitor in the natural gas market (Miles and Holmberg, 2014).

Australia

Australia is a well-positioned LNG producer to take advantage of vast natural gas reserves, as well as their relative proximity to the Asian market. This could make Australia a major actor in the LNG supply race in a long-term perspective. However, with relatively high production costs compared to other actors they could be outcompeted. These high production cost have been driven by Australian dollar appreciation, higher labour expenses and weather delays. In the short term, these production costs can cause Australia to become less competitive in the LNG industry.

Africa

Africa is one of the first LNG export regions, and is experiencing a period of intense growth in their export capabilities. The region once supplied LNG to North America and is now developing new export projects alongside its former customer. A 53-day maintenance period at an Angolan LNG export plant affected the spot market prices in Asia, which illustrates the importance and sizable share of the African LNG (Miles and Holmberg, 2014). As Russia, Africa is a big actor in the LNG supply market on both short and long-term outlooks.

Middle East

Qatar has been a global leader in LNG exports and will continue to be a major player even by only staying on current course. The CEO of Qatargas recently commented on the impacts of shale gas: ”Gas prices will remain regionalized for the foreseeable future and the North American exports pricing structure will not attain the scale and pace that would allow it to significantly alter the current pricing structure in the regional markets of Europe and Asia” (Miles and Holmberg, 2014). His statement is in contiguous with natural gas analyst Bill Powers, claiming that US LNG predictions are overly optimistic.

Summing up competitive rivalry and supply power

The US could become a supplier in the long term, but this relies on a lot of factors. The current state of their infrastructure and the reduction in the high production rates could mean further postponement of the US as a major LNG exporter. In regards to Russia, Africa and Qatar they are, and have the reserves and commercial viability to be major actors in the LNG supply market on both short and long-term outlooks. A recent report from the International Gas Union (IGU) has projected that the US will not have their export LNG train projects online until 2017, which underlines the point about not becoming a major supplier in the short term (IGU, 2014).

6.2.2 Buyers

Europe

With an economic downturn and reduction in natural gas demand as mentioned earlier, analysts see the continent recuperating from this downturn resulting in a increased natural gas demand. The U.K. and Spain have been and will likely remain as major importers of LNG in Europe. The European market is offering a price around 10 USD/mmBtu compared to Asian prices at just short of 20 USD/mmBtu, making suppliers of LNG focus their attention on Asia (Platts, 2014). This could result in higher price in Europe, which is positive for a Norwegian supplier because of the already committed gas infrastructure and a shorter shipping distance.

Latin America

Many of the countries in South America are net importers of LNG, particularly Chile, Argentina and Brazil. As the region is growing in demand, they have been competing with the Asian market for LNG imports. Especially in Brazil were LNG is used as a buffer for drought conditions with reduction in hydro power, we see short term increases in spot prices because of already tight global demand. During the World Cup being held in Brazil this summer, the LNG imports may increase to have sufficient electricity during the tournament, probably causing price peaks in the LNG market.

Asia

The race for the Asian market premium has been a common statement after the Fukushima disaster in Japan in 2011. Experts are expecting demand to grow in Japan, South Korea and India (Miles and Holmberg, 2014). The region is very promising for high demand and stable high price in short term perspective. In the long-term perspective analyst are predicting that the high prices in Asia will continue. Japan, which get their energy supplied nearly only by LNG, is still in large energy deficit. Even three years after the Fukushima incident its predicted that only 14 of the 45 nuclear reactors resume production (DN.no, 2014). Nonetheless, nuclear power only being 30% of Japanese total production, there is still good indications for LNG supply on both short and long term.

Summing up buyers

Asia has been, and will most likely be the driver of global demand in the LNG market. But even though most of the attention is focused towards the Asian market, there are still other buyers such as the South America market eager for supply of LNG. A market with competition for demand is highly attractive for Norwegian export outlooks. Also, with the main attention from the suppliers focused on the Asian and South American markets, this could mean higher prices in Europe as well. In addition, Russia provides natural gas to Europe mainly through Ukraine. The current crisis has yet to interrupt exports, but if this would become a reality, prices would spike up also in the European market (Bloomberg, 2014).

As of today, the regional market prices, especially in Asia and South America, are very attractive for LNG exports. The European market is returning to its normal course after a small economic downturn and there could be promising times for LNG production and export both on short and long-term basis. However, we still have to emphasize the importance of Japan, which is the main driver as the world's largest LNG importer.

6.2.3 New Entrants

Huge capital investments are necessary to enter the LNG supply industry. In addition, most of the companies operating with LNG are major petroleum companies, most of which are positioned in all parts of the value chain. The development from exploration and production to distribution is very capital intensive and is highly regulated and governed. Additionally, there are high levels of technological and financial risk involved in such investments. The trend is that already well-established companies in the petroleum industry are investing in LNG transportation capabilities. It is definitely affordable for actors to enter into the market if they are of a certain size, but often when investing in LNG there are financial imposes. The banks issuing loans for these projects require contracts to be in place, to secure against the financial risk involved. "Even companies the size of Chevron don't build LNG plants without having contracts in hand" says Chief executive officer of Chevron John Watson (Penty and Olson, 2014). He adds that there are no worries for LNG export oversupply, because the facilities are simply too expensive to build without any buyers in place.

Due to the costs and financial risk involved in building LNG export capacity, the threat of new entrants in the LNG supply market is considered low. There are predictions in the outlooks made by the International Energy Agency (IEA) that there would be a potential oversupply in LNG, but Chris Finlayson, CEO of BG Group says otherwise: “As an industry that tends to systematically overestimate future supply and underestimate demand, we have been here before” (Lngindustry.com, 2014). LNG exports forecasts from the US and their predictions seem to be somewhat optimistic, which is a compiled understanding in the natural gas industry.

6.2.4 Substitutes

According to the IEA (2013) natural gas is expected to have a higher growth rate than oil. In their projections natural gas is expected to gain a significant share in the energy sector. Even though substitutes such as oil and coal have strongly developed infrastructures compared to LNG, the industry still has better projections compared to its substitutes (IEA, 2013).

Even though there is an increased focus on the environment, CO_2 emissions have continued to rise. Natural gas emits 40% less CO_2 than burning oil, and 78% less than by burning coal, which is a clear advantage for natural gas against its substitutes (Fairbanks Natural Gas, 2005). Natural gas provides a cost-effective bridge towards a low-carbon future for fossil fuel production.

In regards to LNG transportation there are no substitutes other than pipelines. Transportation of natural gas through offshore pipelines compared to LNG is not economical for distances longer than 1600 km, which means that there are no substitutes for LNG transportation between regional markets (Durr et al., 2005). However, the advantage of using pipelines for shorter distances is that there is no need to build expensive liquefaction and regasification facilities. Nonetheless, pipelines are fixed and will never offer the same flexibility as LNG.

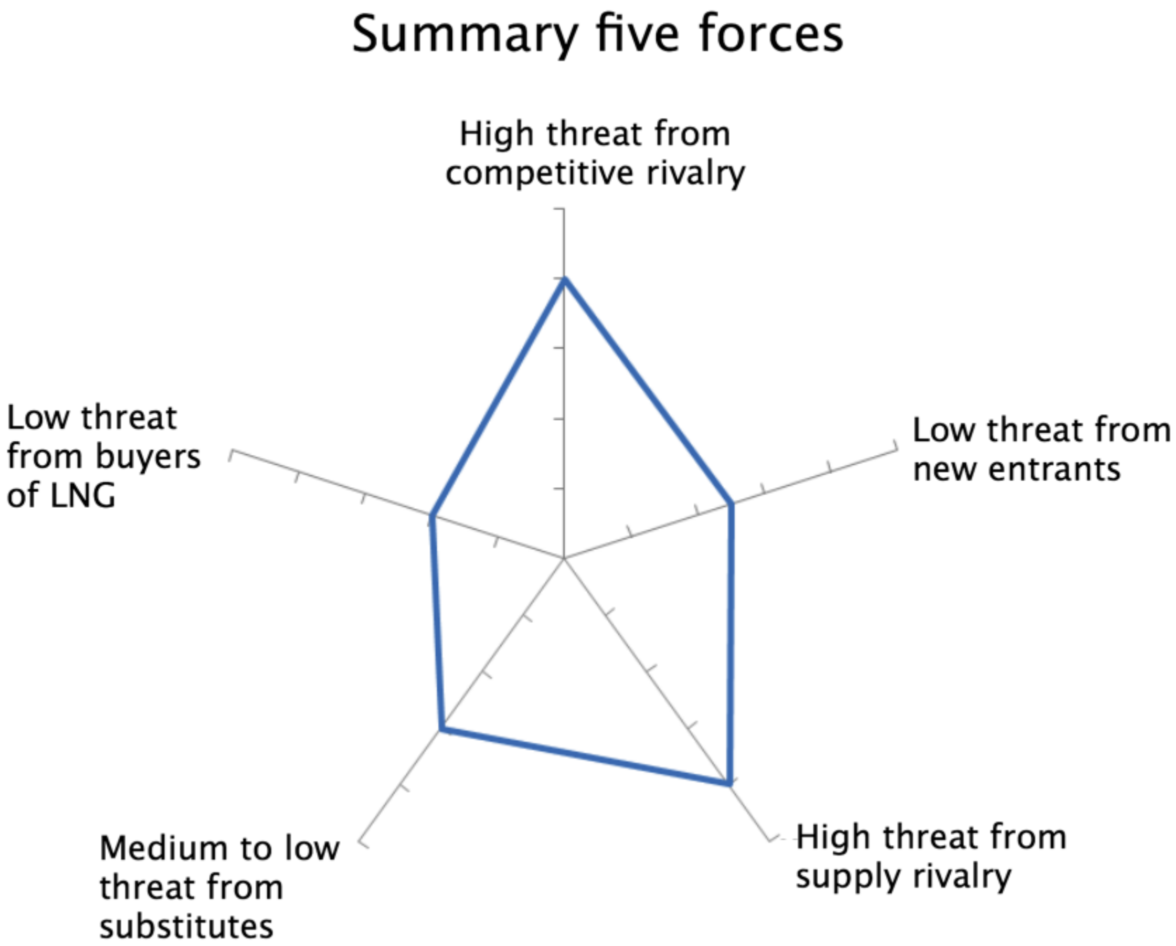


Figure 6.1: Summary five forces

6.3 Summing up

Summing up the analysis we see that the main threat lies in the competitive rivalry and supply power. In this type of market a high level of competence is required to compete with the major suppliers such as the US and Russia. The cost intensive nature of the industry implies that high investment capital is a necessity. If those two components are met from an investment perspective, there are no high threats from other market forces. The limited threats increase the potential overall profit and make it an attractive market to invest in.

7 PRICE FORECASTS

In order to do a quantitative valuation of having a LNG carrier, we need future prices for both regional markets included in our cases: Japan and Europe. Firstly we will do an empirical analysis of the data we use. Further, a model will be fitted to each of the two time series created from the data. By fitting a model we will be able to create statistical forecasts with prediction intervals. These statistical forecasts will then be a baseline for the creation of three different price scenarios based on judgmental forecasting.

7.1 EMPIRICAL ANALYSIS OF THE NATURAL GAS PRICES

The years from 2006 to December 2008 describe the “super cycle” observed up to the start of the financial crisis. As a result of economic recession there was supply abundance driving the prices down. US prices has from then sustained at low levels due to the shale gas revolution and the domestic energy policy. From the beginning of 2011 the regional prices starts to drift and forming the current price situation.

For both Japan and European prices there is a long-term increase in the data. This positive trend is especially visible in the LNG price in Japan, where the price in the sample started just above 5 USD/mmBtu, and ends at around 17 USD/mmBtu. To see if there are seasonal patterns in the data series, seasonal deviation plots are made. Figure 7.1 and 7.2 shows seasonal subseries, where the data for each month is plotted in separate mini plots.

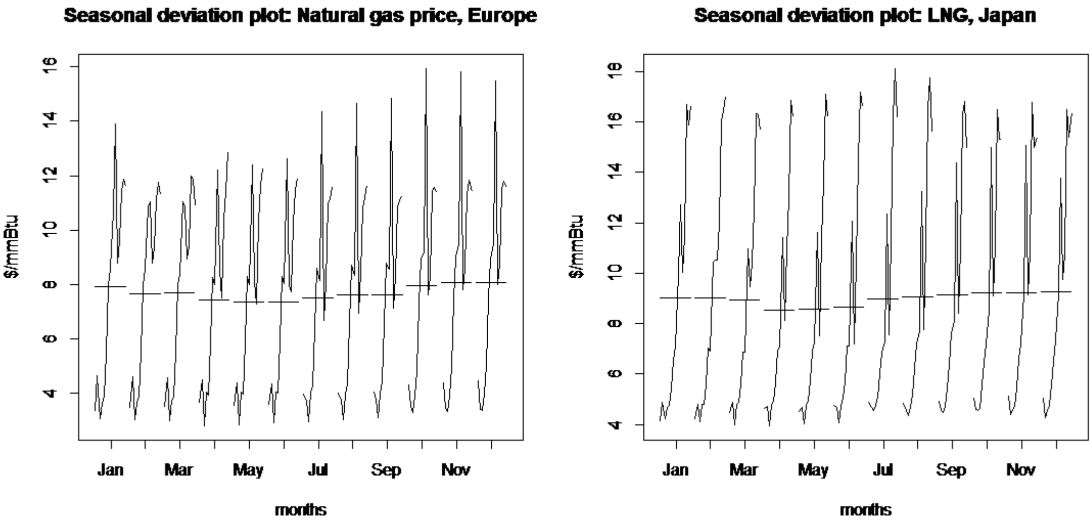


Figure 7.1 and 7.2: Seasonal plot of monthly natural gas price in Europa and Japan

The horizontal lines are the means for each month. Neither the data series for Japan, nor the data series for Europe show any major signs of a seasonal cycle. From the means of each month it is possible to see that there is a minor difference between the summer and the winter months. For that reason, seasonality will not be included in the modeling or the future prices. If daily spot prices had been used instead of monthly averages we probably would have had clearer seasonal effects for both time series. This is because of the price spikes, and thereby increased volatility, during the winter compared to the summer (Alterman, 2012).

7.2 Modeling procedure

From here on we will analyze the two time series separately, as they might show different traits. Further we will fit a non-seasonal ARIMA model to each set of time series data.

7.2.1 Japan time series

From the plot of the time series (Figure 4.1) it seems that there is a minor change in variance, which usually means heteroskedasticity. This suggests that the time series should be power transformed to make it more stable. From figure 7.3 we see that the maximum log-likelihood of the parameter λ equals to -0,585.

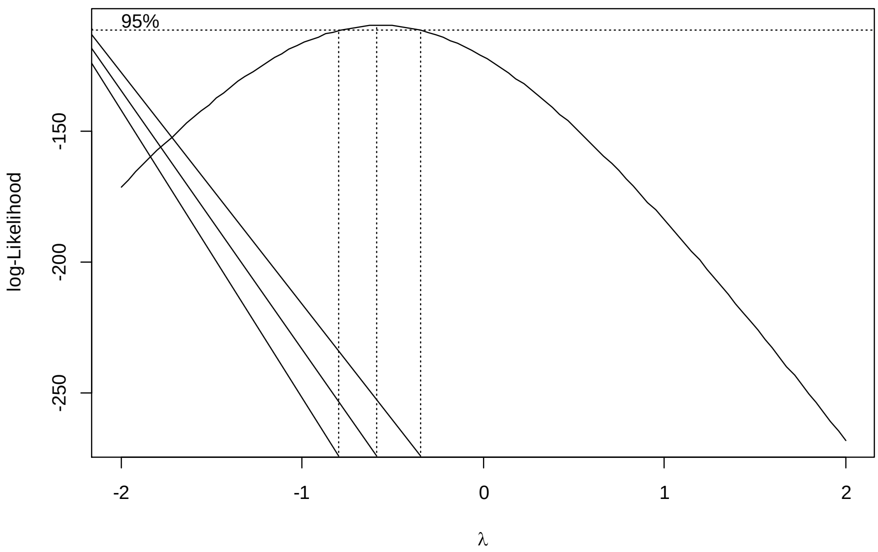


Figure 7.3: Maximum log-likelihood of Box-Cox transformation, Japan time series

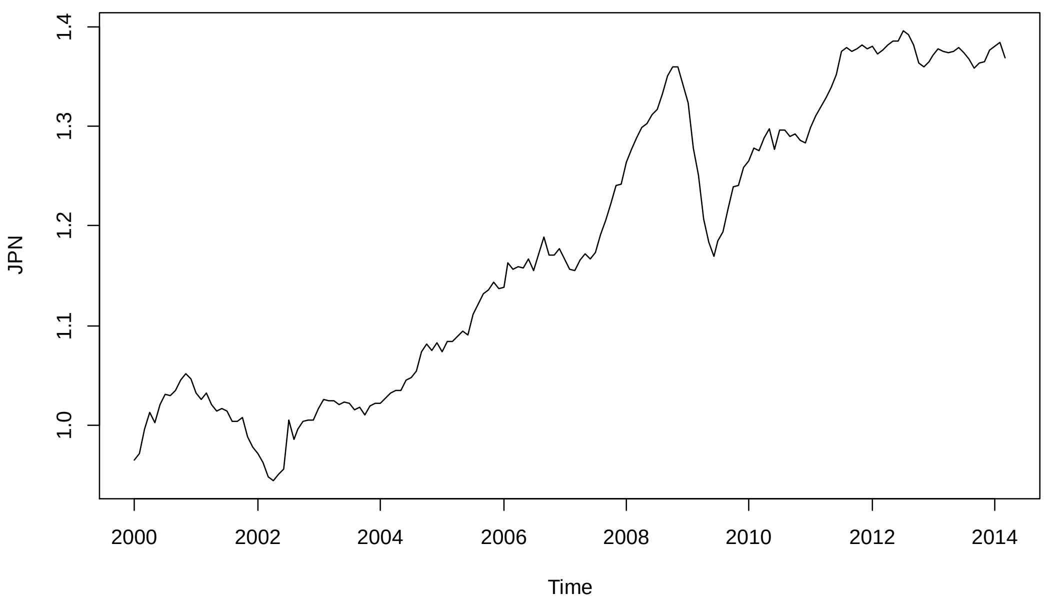


Figure 7.4: Power transformed Japan time series with λ = -0,585

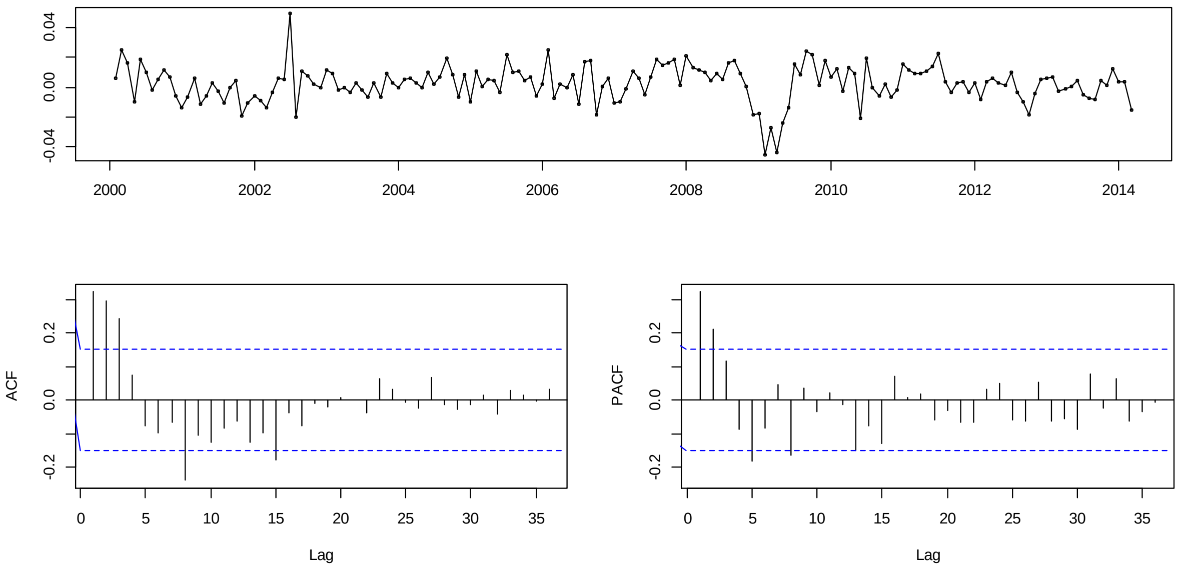


Figure 7.5: Time plot and ACF and PACF plots for first degree differencing of power transformed Japan time series

The transformed time series in Figure 7.4 is clearly non-stationary as it wanders upwards. Consequently, a differencing of the data is done. The data seemed to be somewhat stationary after a first differencing, as seen in Figure 7.5, except for a huge variance cluster around 2009. This is very likely to affect the accuracy of the model. The PACF in Figure 7.5 suggests an AR(2) model. The initial candidate model is ARIMA(2,1,0) . After fitting some variations of this candidate model, ARIMA(2,1,2) shows a slightly lower AICc. Since R does not give any p-values in the output, the significance of the coefficients can be calculated by z = estimated coeff. / std. error of coeff. If |z| > 1.96, the estimated coefficient is significantly different from 0. Looking at Figure 7.6 none of the coefficients have an absolute z-score lower than 1,96.

```
Series: transjpn
ARIMA(2,1,2)

Coefficients:
         ar1      ar2      ma1     ma2
      1.3723  -0.6712  -1.1747  0.6991
s.e.  0.1278   0.1442   0.1399  0.1559

sigma^2 estimated as 0.0001175:  log likelihood=527.63
AIC=-1045.27   AICc=-1044.9   BIC=-1029.59
```

Figure 7.6: R output with ARIMA (2,1,2) fitted to Japan time series

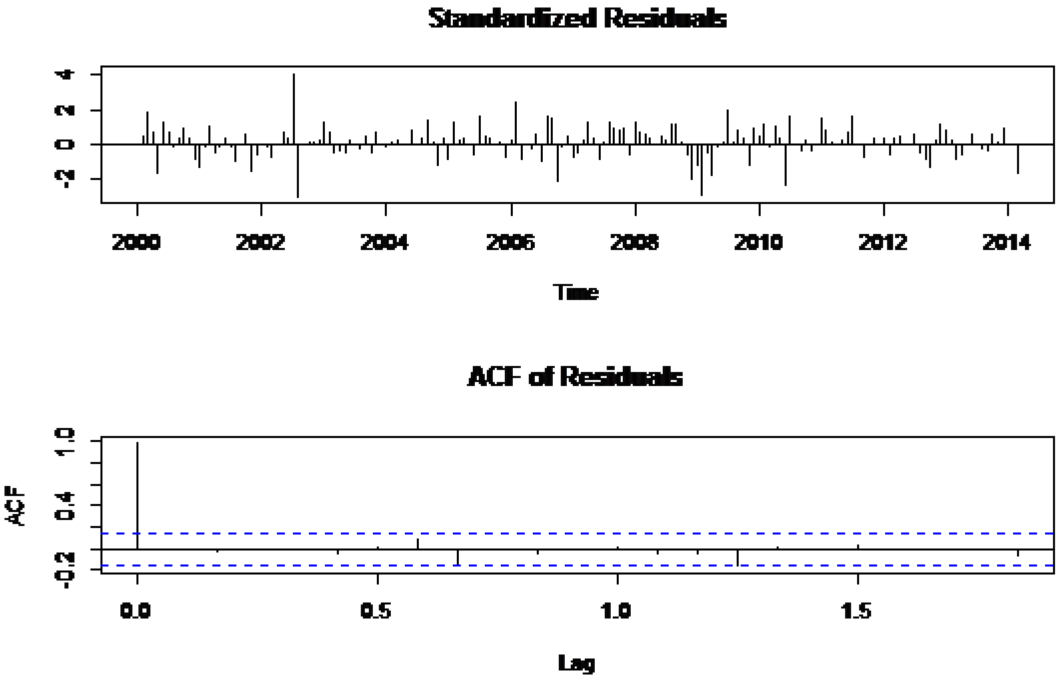
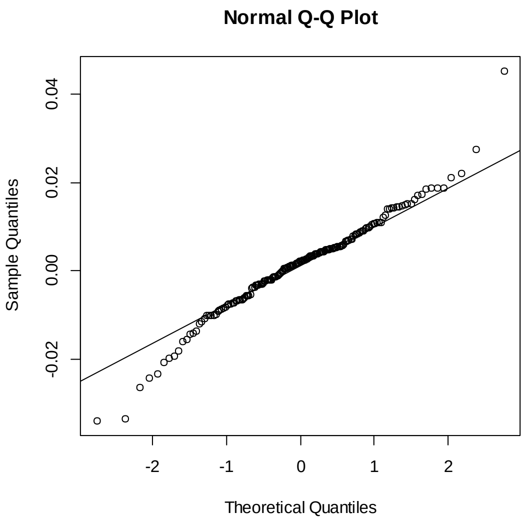


Figure 7.7: Plot and ACF of residuals (lag is in years) from ARIMA(2,1,2) fitted to Japan time series



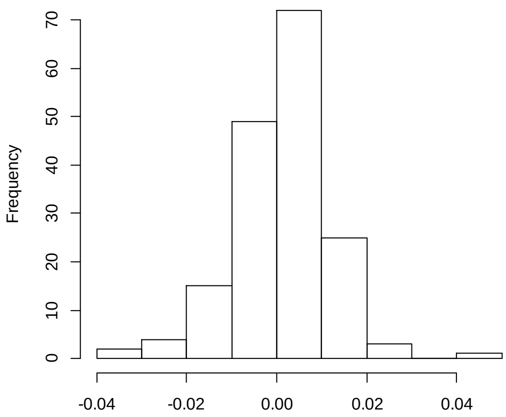


Figure 7.8 and 7.9: Q-Q Plot and histogram of residuals from ARIMA(2,1,2) fitted to Japan time series

```
        Box-Ljung test

data:  transjarimaforecast$residuals
X-squared = 17.0586, df = 11, p-value =
0.1062
```

Figure 7.10: Box-Ljung test of the residuals from ARIMA(2,1,2) fitted to Japan time series

The plot of the residuals seems to be reverting around a value of 0, but there are some clusters of positive and negative volatility, respectively around 2008 and 2009 (Figure 7.7). From the ACF plot we can see that there is no significant correlation in the residuals. To further test that the residuals were not distinguishable from white noise a portmanteau test was done. The lowest of the p-values for lags in $h = min(10, T/5)$, was 0,1062. Although this was rather close to the significance level, every other p-value was relatively high, indicating that there could be independence. Nonetheless, the histogram of the residuals does not seem to be normally distributed, which means that the model did not perfectly capture information in the data. It is slightly skewed to the right and has some outliers. The question is therefore: is there a better model? Many of the outliers, as seen in the Q-Q Plot, are identified to be around the time of the financial crisis. In addition, there is an unexplained sudden spike mid-2002. During the financial crisis around 2009, the variance increased, and this is an event that cannot be predicted only using a univariate time series analysis. This is also supported by comparing the standardized residuals plot and the plot of the first differenced time series (Figure 7.5 and 7.7). Obviously, one cannot simply ignore an event like that, as it probably could happen in the future. By using a model that does not capture such sudden changes, the prediction intervals computed assuming a normal distribution may be inaccurate. However, the forecast baseline will probably be quite good. Box said that all models are wrong, but some are useful (Hyndman, 2014b). The purpose of this statistical forecasting was to get a set of values that will be adjusted using judgment, and finally used in a valuation analysis. Hence, the forecast values from the fitted ARIMA model will be used.

7.2.2 Europe time series

Just as with the Japan time series, the one for European natural gas prices seems to have a minor change in variance around and after year 2008. A power transformation with λ equal to 1/7 was done.

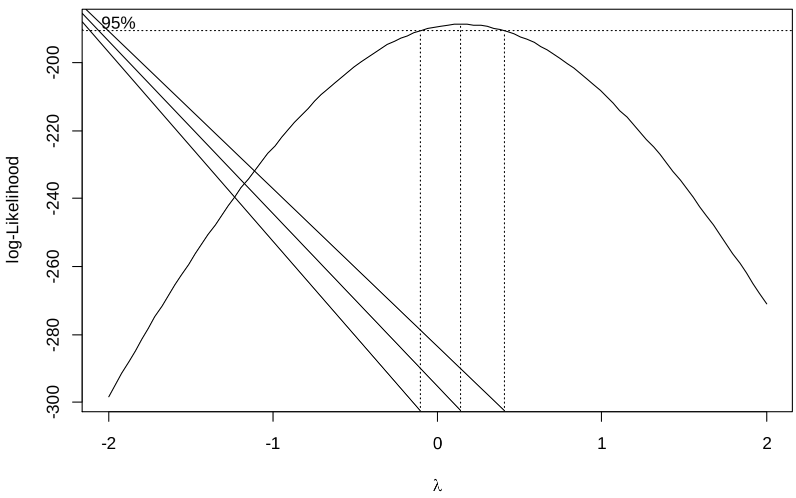


Figure 7.11: Maximum log-likelihood of Box-Cox transformation, Europe time series

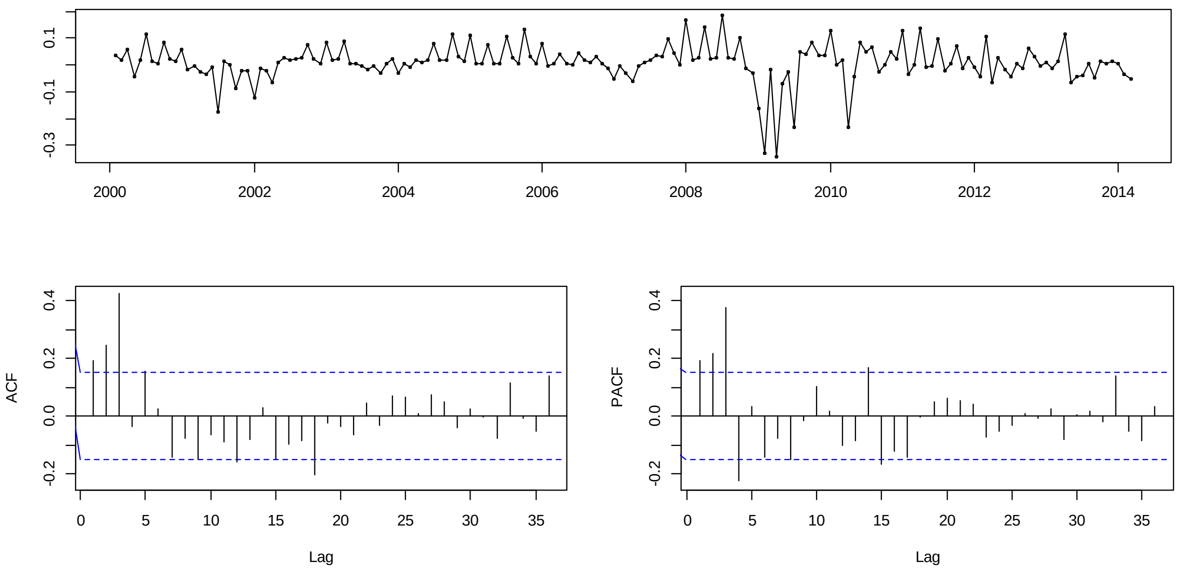


Figure 7.12: Time plot and ACF and PACF plots for first degree differencing of power transformed Europe time series

The transformed Europe time series seemed to be somewhat stationary after a first differencing, except for a huge variance clusters around 2008-2009 and one of the first months of 2010. This is very likely to make the residuals look nothing like white noise, and thereby affecting the model's accuracy in a much greater extent than the japan time series. To avoid this, the length of the time series was changed. Instead of starting in year 2000, which did not include a spot term from NBP, the alternative transformed time series starts in April 2010. By doing so, the strength of the longer term forecast is somewhat diminished. However, the long-term forecasts include a judgmental evaluation.

The ACF in Figure 7.13 shows that the first differenced shorter time series looks like white noise. The model ARIMA(0,1,0) without growth also had the lowest AICc.

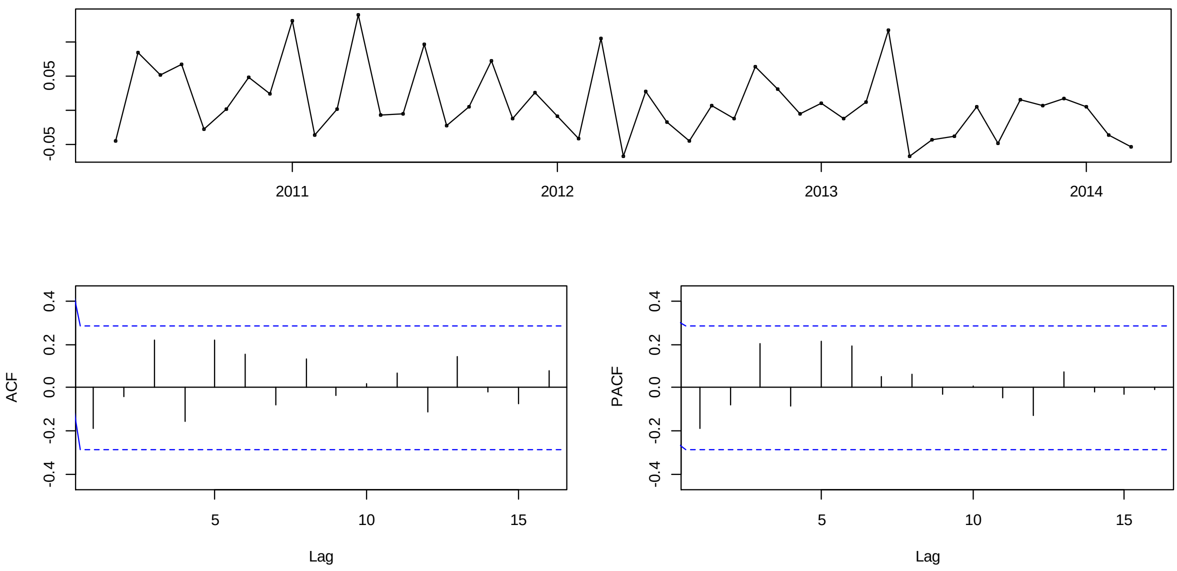


Figure 7.13: Time plot and ACF and PACF plots for first degree differencing of alternative power transformed Europe time series

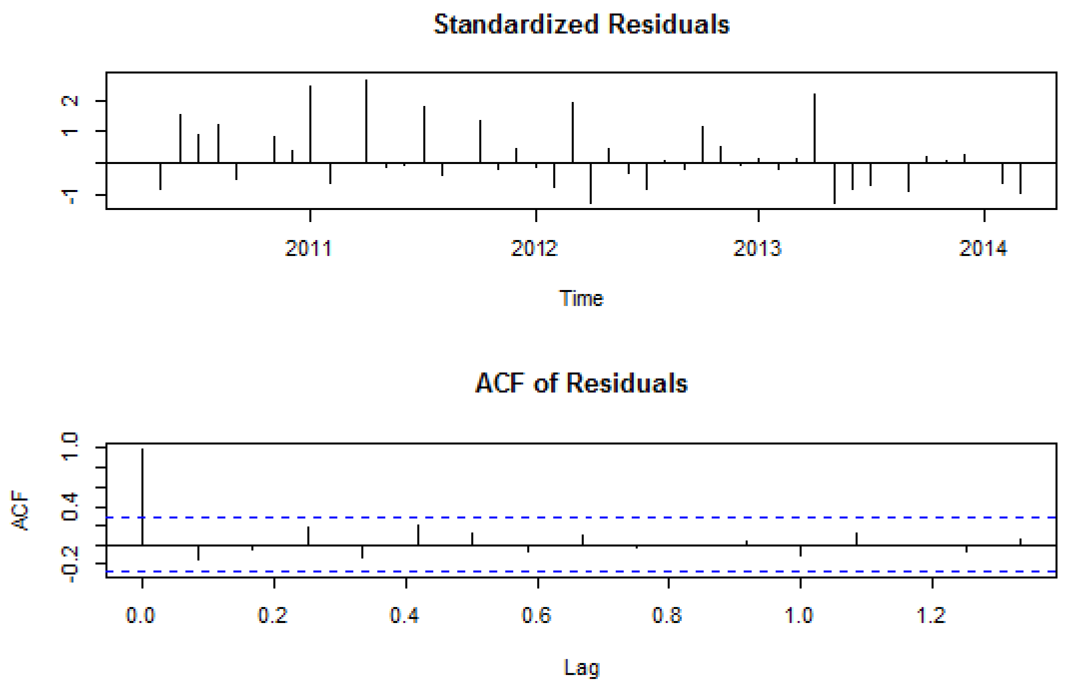


Figure 7.14: Plot and ACF of residuals (lag is in years) from ARIMA(0,1,0) fitted to alternative Europe time series

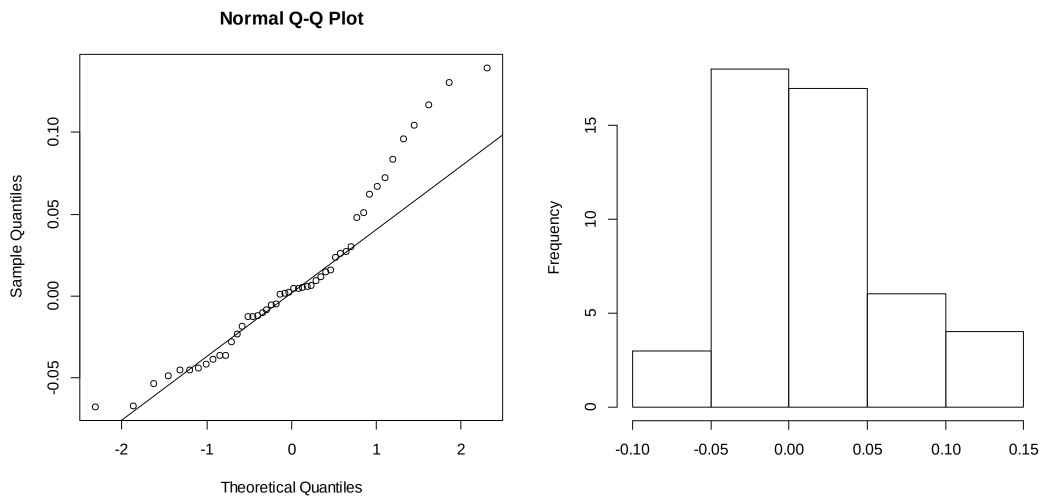


Figure 7.15 and 7.16: Q-Q Plot and histogram of residuals from ARIMA(0,1,0) fitted to alternative Europe time series

```
        Box-Ljung test

data:  ketarima$residuals
X-squared = 11.558, df = 10, p-value = 0.3157
```

Figure 7.17: Box-Ljung test of the residuals from ARIMA(0,1,0) fitted to alternative Europe time series

The ACF indicates that the residuals are white noise. A Box-Ljung test also shows that there is a possibility of independence. But, the Q-Q Plot and the histogram of the residuals does not show normal distribution and there are quite a few outliers. One possibility is that by shortening the time series there is simply too few data points to fit a good model. The data could also be distorted, as it consists of many different natural gas prices in Europe. Hence, the average estimate does not follow the same movements as a single spot price would have done. In addition, there could be some skewness to how these prices constituting the data, are moving relative to each other, and/or the weighting of them.

7.3 STATISTICAL FUTURE PRICES

Since both models were estimated with the use of a power transformation, the forecasts were back-transformed with their respective λ -value. As a consequence, both forecasts' upper 95% and 80% prediction intervals "sky rocketed" respectively after 2020 and 2030 equaling non-realistic prices, and was not included. For the Japan time series, the forecast mean has some minor changes until it stabilizes at 14,37 USD/mmBtu in 2017 (Figure 7.18). The statistical forecast mean for Europe is 10,88 USD/mmBtu (Figure 7.19). For both time series the lower prediction intervals exponentially decline. Although there is a possibility of the market becoming efficient and prices converge, it is very unlikely that they go below the lower 95% or even lower 80% prediction interval. If the market becomes efficient the margins will probably stay positive, but to a much lesser extent. However, if the prices become too low, the production and transportation costs will not be covered, resulting in negative margins. In turn, this means that there will be less willingness to explore and produce natural gas. As a baseline for the judgmental adjustments, the prices will not go under the lower 95% prediction interval.

7.3.1 Japan

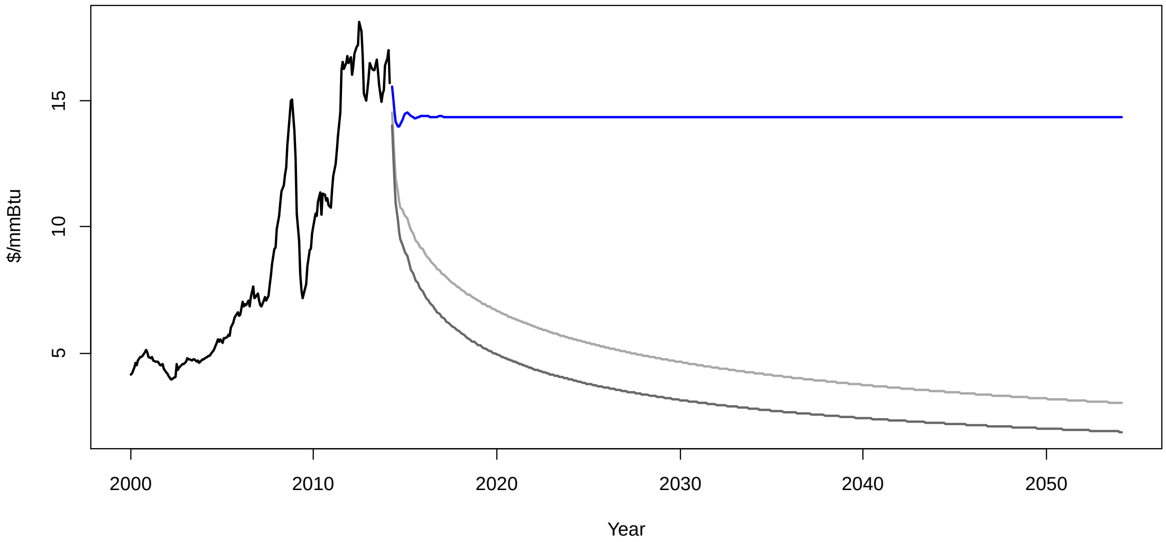


Figure 7.18: Future LNG price in Japan, mean (blue) and lower 80% (light grey) and 95% (dark grey) prediction intervals

7.3.2 Europe

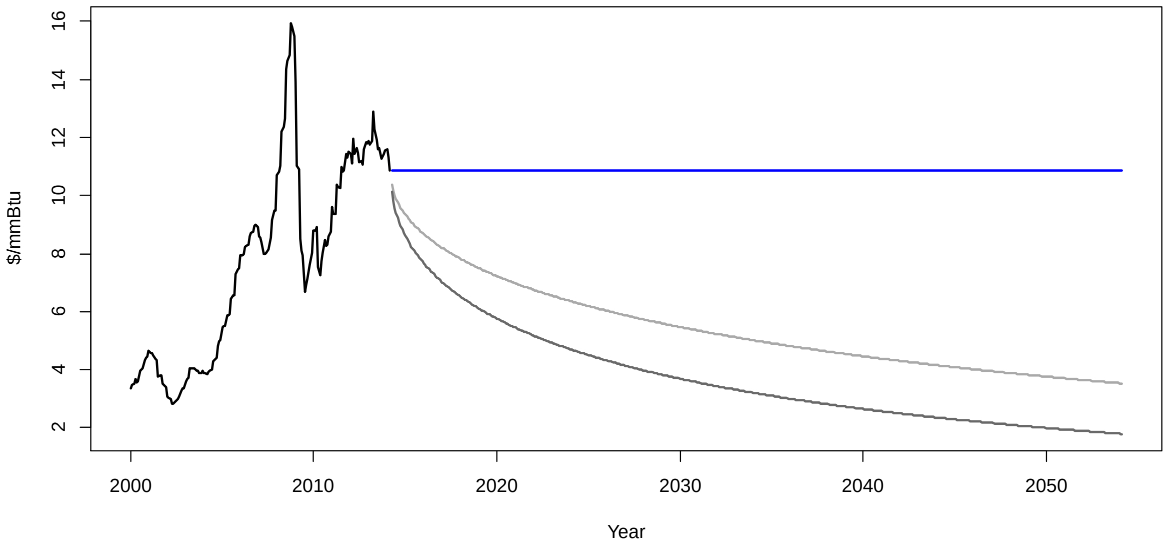


Figure 7.19: Future natural gas price in Europe, mean (blue) and lower 80% (light grey) and 95% (dark grey) prediction intervals

7.4 JUDGMENTAL PRICE SCENARIOS

Using a systematic and well-structured approach we will here create price scenarios based on the statistical forecasts and the strategic analysis of the market in Chapter 6. The forecasts will be categorized either by a high, medium or low price scenario, and remain constant after a 10-year period. The reason for doing so is that we have no argumentation beyond a relative long-term basis of 10 years. Adjustments beyond this period would be mere guesses.

Over the past five years a surge of optimism for US unconventional gas production have transformed North America from an LNG importer to a possible frontier for LNG exports. While global LNG demand continues to grow, North American imports are dropping simultaneously as investments in LNG export capabilities are bottlenecked by government approval. With continued rise in price differentials between the Asian and North American market, investors are eager to take advantage of the situation. The US has the largest queue of projects in the LNG industry, with 28 liquefaction projects has been proposed, representing nearly 285 MTPA of those 188 MTPA with already announced start dates (IGU, 2014).

In the low price scenario the high demand for LNG and a high historical price level has allowed many projects to be accepted. The focus on the high profits from the Asian premium market has led to an oversupply, as big players such as the US, Russia and Australia intensives their production and exports. Such a growth in LNG supply could lead to a drastic price reduction and convergence in prices, making the market become more efficient. Japan has been an important driver behind the growth of LNG by being the number one importer after the Fukushima incident. In this scenario they resume their nuclear power production, and thereby reduce their need for LNG. The prices in this low scenario will steadily drop down to 8 USD/mmBtu and 9 USD/mmBtu in Europe and Japan respectively after 2024.

In addition to difficult regulatory approval process, US liquefaction projects also face some commercial uncertainty, which could further limit LNG exports. Regulatory obstacles combined with desire not to repeat the regasification overbuild phenomenon of the late 2000s causing high price volatility at henry hub, LNG export projects will most likely be limited to the end of the decade. If many of those projects go as planned it may cause an oversupply, which the LNG industry cannot absorb, causing prices to decline. In the medium scenario the

US does not manage to export as much LNG as planned. Australia and Russia increase their exports, but the overall demand, especially in Asia, grows at the same rate, maintaining the price-levels of today. The statistical forecast will be used as a baseline, as there are no significant shifts in current market dynamics for this medium scenario.

In order to include the US as a major exporter of LNG, a lot of factors have to fall in place, as mentioned in the strategic analysis. In the high price scenario, neither the US, Russia nor Australia manages to increase exports as much as the growth of LNG consumption. Here, demand in Asia and Europe will grow at a quicker rate than new supply arises, causing the market prices to rise with a spread similar of today. In this price scenario the prices will steadily grow up to 16 USD/mmBtu and 20 USD/mmBtu in Europe and Japan respectively after 2024.

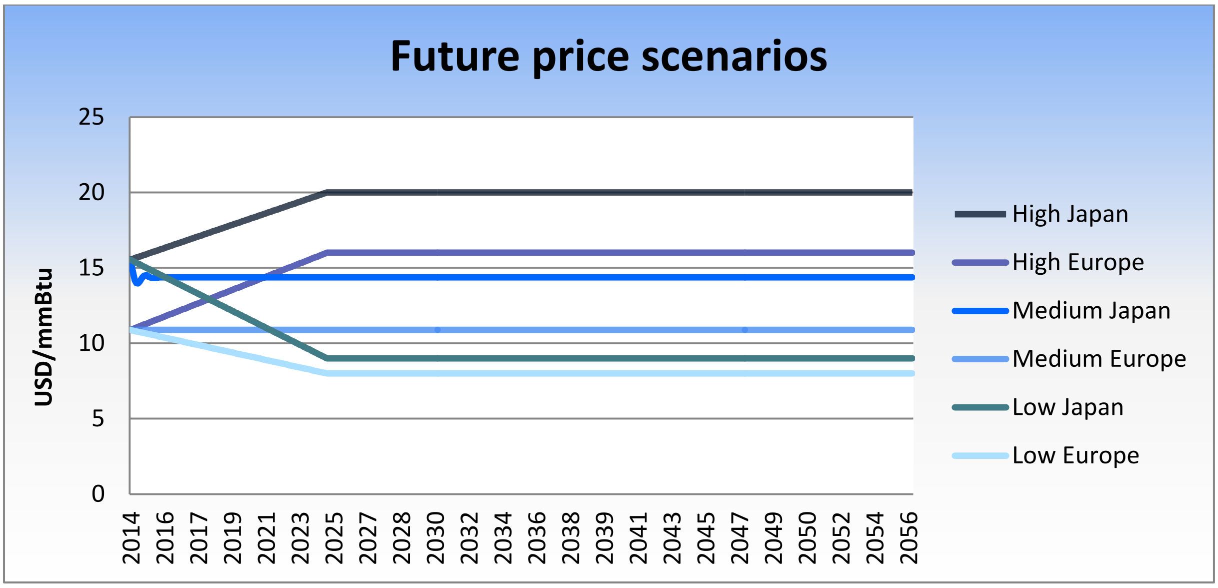


Figure 7.20: Future price scenarios in Europe and Japan

7.5 Forward price

In the first case we have a forward contract towards the European market. A spot-forward relationship with the assumption of no-arbitrage is a common way of pricing a forward contract in a commodity market. The forward price for a maturity T determined as $f^T(t)$ is related to the spot price at date t by the fundamental relationship:

$$f^T(t) = S(t)\, e^{(r-y)(T-t)}$$

In this equation r is the continuously compound interest rate prevailing at date t for maturity T and y is the convenience yield of the commodity (Geman, 2005). The convenience yield is an adjustment to the cost of carry in the non-arbitrage pricing formula. The cost of carry hypothesis is the theory that the forward price is equal to the spot price plus the cost of carry. The cost of carry can be formulated as the cost of storing a physical commodity over a period of time.

We are interested in a forward contract for a period of up to 40 years, thus the cost of carry is too far into the future in order to make a suitable figure. After 40 years the common perception may be converging natural gas prices minus the transportation costs between the various regional markets. With converging prices and a more efficient market the defining powers of the market price is supply and demand. In this case a forecast of future supply and demand would be necessary for a forward price. In a conservative forecast, with higher supply than demand on long term due to massive projects in the US, a downgrading of the price on long term could occur. This is reflected in the low price scenario.

A forward price between two parties is commonly the difference between the spot price and a forward price premium. Such a long life span for a forward contract puts all the risk is on the issuer of the contract. The issuer of the contract therefore requires compensation in the form of the mentioned forward premium in case 1. As a supplier it is important that the forward price also is above the break-even price of the supply costs, in order to make the contract profitable. The current spot price at NBP is 11 USD/mmBtu (Platts, 2014) Meanwhile, the break-even price when transportation to Milford Haven is accounted for is 6,8 USD/mmBtu. Accordingly the forward price should be somewhere in between these two figures. In the low price scenario the price in Europe is 8 at its lowest. We therefore assume a forward price of 8,5 USD/mmBtu.

8 Investment analysis

What we have done so far is to describe the market situation and the economic availability from a qualitative approach, and forecasted a set of price scenarios for Europe and Japan. The purpose of this next part is to investigate from the economic value of different LNGC utilization from a quantitative approach. In order to find the economic value we must establish an investment proposal, the economic tool of evaluation and the scenarios from our Norwegian point of view.

8.1 Shipping assumptions

There are two shipping possibilities towards the Asian market from Hammerfest, through the Suez Canal and through the NSR. We assume that there are 365 days a year available for sailing. In order to get an accurate measure of the distance involved in shipping from Melkøya to Yokohama harbor in Japan, we have used some of the estimates made by Tschudi shipping Company AS. The company has a long history from operating in conventional and unconventional shipping markets, and has made calculations about the route through an international knowledge hub called the Centre for High North Logistics (Gunnarsson, 2013). These calculations offer a good estimate of the distance; however it is important to mention that these numbers may vary depending on conditions. Changes in ice structure from one year to the next means that voyages through the NSR never are identical. For our calculations going through the NSR we will use an average speed of 13 knots and a distance of 5,800 nm. These numbers give us a preliminary idea of the distance and time benefits for sailing through the NSR compared to the Suez Channel. The distance used between Hammerfest and Yokohama going through the Suez Canal is set to 12,500 nm. The Suez Canal route is to be considered blue water, meaning that there are no limitations, unlike the Arctic route, to speed. The average speed for this route will be 19 knots, which is assumed to be the most cost effective speed for the ship we are investing in.

The Japan spot case will be based on going through NSR during the summer months, and through the Suez Canal the rest of the year. The NSR is assumed to be open five months of the year, which equals to 150 days. The reason for using this alternative is the potential of costs and time saved, compared to the Suez route. For the scenario towards the European market our assumptions is based on a voyage from Hammerfest to a LNG terminal in Milford Haven, in the UK. This voyage is also a blue water route, and the average speed will also be 19 knots. This one-way distance is 1,500 nm (Sea-distance.org, 2014). Every scenario is based on round trips. This means that the LNG carrier would return to Melkøya with an empty cargo hold. With the mentioned speed and distance in mind, the number of days is takes for a round trip from Hammerfest to Yokohama and Milford Haven can be calculated.

In order to not make the calculations to complicated, there are no stops along the route. In addition, the ship requires 3 days for loading/unloading, documentation, discharging, and any waiting time, in each port (Canaport LNG, 2013). To calculate the days for a round trip we use the following formulas:

$$Number\ of\ sailing\ days = \left(\frac{Distance\ (nm)}{Speed\ (knots)\ \times\ 24} \times\ 2\ (roundtrip)\right)$$

$$Number\ of days\ per\ round\ trip = number\ of\ sailing\ days + 6$$

With these assumptions we get the following sailing and round trip days for each voyage:

- Hammerfest ↔ Milford Haven = 6,6 + 6 = 12,6 days
- Hammerfest ↔ Yokohama (Suez Canal) = 54,8 + 6 = 60,8 days
- Hammerfest ↔ Yokohama (NSR) = 37,2 + 6 = 43,2 days

For the Milford Haven and Suez Canal voyages it is straightforward to find the number of round trips per year given the assumptions above, and we are going to illustrate this through the Suez Canal scenario:

$$Number\ of\ round\ trips\ per\ year = \frac{365\ days}{60{,}8} = 6$$

For the Milford Haven scenario we get 29 round trips. The following calculation can illustrate the benefit of additionally using the NSR, as compared to only using the Suez Canal, to get to Japan:

$$Number\ of\ round\ trips\ per\ year = \frac{150\ days}{43{,}2} + \frac{365 - 150\ days}{60{,}8} = 7$$

Specifically, we get 3,47 round trips per year using the NSR. We will calculate 3 round trips plus for both Japan routes, and one were the ship goes eastbound through NSR and westbound through the Suez.

8.1.1 The LNG carrier

For all cases we will base our costs on a fictive LNG carrier with Ice class 1A, delivered in the second project year, i.e. 2016. The vessel will be winterized. Winterization is modifications of a vessel that ensures safe, effective and efficient operations in freezing temperatures (Sawhill, 2013). The focus lies on controlling the adverse effects of icing, freezing, wind chill and material properties in cold temperatures. These modifications includes: structural design to reduce icing and cold exposure, heating, insulation and drainage, mechanical de-icing, and weather shielding. To run these modifications, more electricity is needed. Hence, the vessel has increased fuel consumption when sailing in Arctic waters. Logically, a vessel sailing slower will use less fuel. However, for the sake of simplicity, we assume that the fuel consumption going through the NSR and blue waters are the same. Ice class rules on vessels are requirements for hull strengthening and machinery for navigation through icy waters**.** A vessel that has these specifications is essential to our investment analysis, as one of the routes goes through the Arctic.

The average capacity of ships in the new-build orders of 2013 was 165 000 m^3 (IGU, 2014). This will also be the cargo capacity of the ship in the valuation. We assume the BOG to be roughly 0,15% of the cargo per day, which covers the daily bunker fuel consumption at the 19 knots, and 13 knots through the NSR. The vessels have a Tri-Fuel Diesel Electric (TFDE) propulsion; this enables use of either marine gas oil, heavy fuel oil (HFO) or LNG depending on the respective price and availability. This means that the preferred fuel can be changed over time. In gas-mode TDFE generators use a pilot fuel in addition to the gas fuel. The percentage of which the pilot fuel is used in gas-mode is set to 5%, as used in a study of LNG fuel by GL and MAN (Andersen, Clausen and Sames, 2011). The pilot fuel can either be marine gas oil or HFO. Although the generators use a higher share of fuel oil during lower loads, we will for the simplicity assume that they run in gas-mode all the time. The daily fuel consumption will therefore consist of:

$$BOG, gas\ fuel = \left(165\,000m^3 \times 0{,}15\%\right) \times 24{,}02mmBtu/m^3 \ = \ 5945\ mmBtu$$

$$HFO, pilot\ fuel = \frac{(165\,000m^3 \times 0{,}15\%) \times 0{,}450m^3/tons}{0{,}95} \times 0{,}05 = 5{,}86\ tons$$

All conversion factors used can be found in Appendix 1. The pilot fuel represents only a small share of the daily fuel consumption, and the total cost. As a consequence, we will not focus too much on it. The price for HFO is assumed to be 650 USD/ton for the whole lifetime of the LNG carrier. The consumption of fuel is voyage-specific, and will be presented later.

Since we are doing an investment analysis from a Norwegian producer’s standpoint, the BOG used for fuel comes rather cheap. The alternative would be to use HFO or another fuel oil equivalent (FOE) to transport the BOG to a market, and sell it at a market price. However, this would imply that all of the BOG was re-liquefied. The process of re-liquefying and re-storing BOG requires electricity, which again means a higher HFO or FOE consumption. Additionally, having re-liquefaction equipment on the vessel would probably also increase the initial investment required. Thus, both options are fraught with advantages and disadvantages. A HFO price of 650 USD/ton equals 15,3 USD/mmBtu (Andersen, Clausen and Sames, 2011). Hence, the carrier will run on gas-mode. Furthermore, the use of LNG as a fuel has environmental advantages compared to the substitutes (IGU, 2014).

All measurements of the investment object will be based on Meridian Spririt, owned by Meridian Spirit ApS (MarineTraffic, 2014). These measurements are very relevant to the voyage-specific costs.

8.2 Cost of equity

8.2.1 Risk evaluation

To find the cost of equity we first have to estimate the risk. Measured as variance, the beta coefficient in the Capital Asset Pricing Model quantifies risk. The model assumes that the investor is well-diversified, and therefore holds no non-systematic risk. In order to assess the risk of this project(s) we have to evaluate the market elements that impact the expected return of the asset. We do this by addressing major risk factors. For each risk element we assign a risk factor between 1 (low risk) and 5 (high risk). To assess the risk of an LNG project there are three levels of market risk important to analyze (Kotzot et al., 2007):

- Project level risk
- Sovereign risk
- Institutional business and legal risk

Project level risk

Project level risk concerns the contractual foundation that protects the investors from market, operating and ownership risk. In regards to ownership we assume that there is no risk, since we want to quantify the risk of the project.

LNG contract risk addresses the financial predictability and reliability of the buyer. High stability and low risk is associated with long-term contracts. In our forward case the risk factor of the project will be 1, since we are fully hedged through the lifetime of the LNGC. In our other cases, where we only trade on spot, the risk factor will be 5. In these two cases the project is vulnerable to price volatility, power of the buyer and other market powers. As these are high(er) risk cases, the β should be higher than in the forward-case.

Technology, construction and operations are crucial to the dependability of the project. These risks can be broken down into pre delivery and post-delivery risk. For this investment the pre-construction would be how dependable the delivery of our LNGC from the shipyard is. This is considered a medium risk factor (3) for all cases, because of the possibility of delayed delivery and its implications on the NPV. The post-delivery risk would be if the project runs successfully to generate revenues for debt service. Since there has been some production stops at Snøhvit we are going to set this risk factor at medium (3). Even though Statoil has dealt with the problem, there is a risk that this might happen again. If there is a production shut-down, the vessel has no product to deliver, so this will be a medium risk for all cases. In our spot cases we will be shipping through Suez and/or NSR. These routes yields a higher operational risk than sailing in blue water in Western Europe, and will therefore have a medium to high risk factor at 4. (Even though Case 2 involves sailing in blue water, we will for simplicity estimate one beta for all spot cases.)

Competitive market exposure depends on the cost of production relative to the market, and is essential for the project risk. Low profit margins means that the project is more exposed to price volatility, which brings concerns if the project will generate profit or losses, causing it to be a high risk factor. If the project has high margins, even if market prices are reduced dramatically, the chance of generating revenue and managing loan payments is higher. High margins would therefore equal a low risk factor. In the spot trading cases, none of the cargoes are hedged against market exposure. This offers very high market risk factor (5). Even though the margins between the current market price and cost of production are high, there is no guaranteed sales price, so this risk has to be taken into account. For our forward contract case all our sales are hedged, making competitive exposure low, equaling a risk factor of 1.

In regards to operational risk, and the risk of the reservoir being used before the lifetime of the asset expires: The Snøhvit field consists of 244 billion cubic meters of natural gas (NPD, 2014). Looking at any case where the shipments go to Milford Haven only, throughout the LNGC lifetime, the deliveries totals about 112 billion cubic meters of natural gas. This is a big part of the field. We can correspondingly assume that the proposed ship is not the only one loading LNG from the Melkøya plant. (This is later discussed in the Conclusion, 9.2.1 Limitations.) Another important point to this risk factor is that the investment payments are done after the first 10 years after delivery, so if the field should run out, the loan payments are covered. This will be rated as a medium risk factor at 3 for all scenarios.

Counter party exposure includes risk from other participants in our operations such as LNG buyers and how reliable they are. Major LNG buyers and counterparts who do business in the

LNG market are well-established companies with strong economic foundation. Therefore this risk factor set to 1.

In addition to the factors above, there are several other factors regarding the overall risk assessment:

The legal structure of the operations is considered very low because the operations are from Norway. The Norwegian government has long experience with petroleum industry, and taxes and other import duties are relatively predictable and consistent.

The currency risk is considered medium since we operate out of Norway and our income is in USD. Currency fluctuations between USD and NOK are obviously a risk factor. Although some of the port dues are in GBP, the small amount makes it negligible.

In the forward case the liquidity of the operations is rather good, because the operation is hedged and there is a high predictability of cash flows. In this case liquidity risk is very low (1). In the spot cases this risk factor is rated high (5), because of low predictability of future cash flows.

The result of our forecasting is based on historical prices and judgmental adjustments. In our forward case the forecasting risk factor is 1, because it is of no concern. In the spot cases the risk factor is considered high (5) because of the difficulty of predicting prices the next 40 years.

Sovereign risk

The country-rating factor gives an indication of the security or the territorial risk for the investment. Country risk include local business environment, economic and political issues. Norway has an AAA sovereign S&P rating, and the sovereign risk factor is considered to be low (1) (Damodoran, 2014a)

Institutional business and legal risk

This risk factor concerns the existence of vital businesses and legal institutions not covered by the sovereign country risk. These risk are considered to be very low (1) in the LNG market, as the market has a well-developed legal structure and our operations are in well-established markets.

Summing up

The risks from the three categories are summed, and a β that represent the risk of the investment is estimated. The β is used in to calculate the cost of equity in CAPM, and will be further used to establish the cost of capital for the cases. The forward case is here "low", and spot cases are "high":

Investment risk		Low	High
LNG contract risk		1	5
Technology and construction	Contract delivery (pre-delivery)	3	3
	Operational risk (post-delivery)	3	4
Competitive market exposure	Market exposure (profit margin)	1	5
	Operational risk (reservoir)	3	3
Counter party exposure		2	2
Legal structure		1	1
Currency risk		3	3
Liquidity risk		1	3
Forecasting risk		1	5
Project level risk		**1,9**	**3,4**
Sovereign risk		**1**	**1**
Relative institutional risk		**1**	**1**
Total risk (β)		**1,300**	**1,8**

The big difference between the two different β is the market exposure, and it is clearly represented in table below as we see a 0,5 higher β in the high risk cases compared to the low risk case. Since we are looking at an investment from a Norwegian stand point we can assume that the investor is well diversified. Hence, the measure of β in the table represents the market risk, i.e. the systematic risk that cannot be diversified.

8.2.2 CAPM

Risk-free rate

To calculate the CAPM we need a risk free rate. Based on the yield of a 10-year Norwegian government bond this gives a risk-free rate of 2,58% (Norges Bank, 2014).

Market premium

The market premium must reflect the additional return an investor can get when investing in a market of a specific country. One way to estimate the equity risk premium for a country is to add country risk premium to a mature market premium. There are several ways of estimating mature equity risk premium. We will use the latest update (May, 2014) of the implied equity risk premium estimated by Damodaran (2014b). Adding CDS default spread of 0, based on the AAA sovereign rating of Norway from S&P, we get a market premium of 5,12% (Damodaran, 2014a; Damodaran, 2014b).

Summing up CAPM

By summing up all the factors in the CAPM-model estimated in the previous sections we can compute the cost of equity for both low and high-risk cases:

$$CAPM_{low} = 2{,}58\% + 1{,}3 \times 5{,}12\% = 9{,}236\%$$

$$CAPM_{high} = 2{,}58\% + 1{,}8 \times 5{,}12\% = 11{,}796\%$$

The two different costs of capital now reflect the risk of the cases. Further, we will use these numbers to estimate the WACC.

8.3 COST OF DEBT

Most LNG export projects use a financing framework typical for large-scale, long-term industrial and public facility constructions. The financing structure is dependent on investment size, the source of risk involved, and the capacity increase absorbing the risk, and is compared against the expected return (Lee, 2013b). According to Thakur (2011) the financing of a LNG vessel usually consists of a mix of debt and equity in the ratio of 4:1. It is further stated that for low risk projects the equity portion can be as low as 10%, and for high-risk projects it can be as high as 30-50% (Kotzot et al., 2007). For the low risk case we assume an equity portion of 20%. For the spot trade cases it can be assumed that the banks issuing the loan for the investment require a higher share of equity, due to the higher risk. In these cases we will assume an equity portion of 40%. This will also affect the difference WACC of

Out of the initial investment, 200 million USD is financed with a loan in our forward case and 150 million USD in our spot cases. We base this financing on a project finance, which means that the lenders loan money for the investment, solely based on the specific risk of the project and its future cash flows. The arrangement creates a separate legal entity to house debt and equity exclusively for the venture, and the projects cash flows then becomes the only source of repayment (Lee, 2013b).

Since there may be a risk of oversupply in the shipping industry because of higher increase in new builds compared to estimated necessity for LNG shipping, there is a risk of supply glut (Tsolakis, 2014). This would mean a higher supply than demand for LNGC, causing a reduced charter rates. Since we are investing in an LNGC for the purpose of shipping exclusively from Snøhvit, we are not exposed to shipping market risk. The risk of our operation, discussed in the industry strategic analysis, is reduced to price risk of the commodity, such as the US on long-term basis. Because of this, the payback period is set to 10 years, rather than the lifetime of the ship. In this way the price risk on long-term is transferred to the project rather than the banks. For the forward case we assume a real loan rate of 5%. In the two other cases with spot, there is a higher risk and therefore we assume a higher loan rate of 10%. The ship has a delivery time of 2 years, therefore the payments to the shipyard is made in installments based on percentages of the contract price and certain milestones achieved in the construction. For simplicity, the payments are made in two equal installments over the two first years of the project. Banks have a higher willingness to come in with finance once steel cutting on the vessel has begun (OECD Council Working Party on Shipbuilding, 2007). However, it is assumed that the loan is provided equally over the two first years. No payments on the loan are made until the vessel is completed and has generated cash flows.

8.4 WACC

The WACC equation is the cost of each capital component and is calculated for both the low risk and high risk cases after taxes. Here, WACC is not based on the capital structure of a company investing in the project, but on the project itself:

$$WACC_{low} = \frac{50}{250} \times 9{,}236\% + \frac{200}{250} \times 5\% \times 0{,}73 = 4{,}7672\%$$

$$WACC_{high} = \frac{100}{250} \times 11{,}796\% + \frac{150}{250} \times 10\% \times 0{,}73 = 8{,}0744\%$$

8.5 Shipping costs

Owning and using a ship for transportation between ports include different costs. The fixed costs are capital costs, and the variable costs are broken down into operating costs and voyage costs (Thakur, 2011).

8.5.1 Capital costs

LNG carriers are technically advanced ships and are very costly with most new builds ranging at 200-250 million USD (Höegh LNG, 2011). Because of the Ice class, winterization and the

TFDE propulsion the total investment is assumed to be 250 million USD. The repayment of capital and depreciation highly influences the ship costs.

Loan payments

As an example we use the forward case loan contract, and the setup is similar for the spot cases.

Forward contract loan	**2016**	**2017**	**2018**		**2025**
Lifetime	1	2	3	…	10
Interest payments	10 000 000	9 204 954	8 370 156		1 233 377
Installments	15 900 915	16 695 961	17 530 759	…	24 667 538
Sum	**25 900 915**	**25 900 915**	**25 900 915**	**…**	**25 900 915**

Spot contract loan	**2016**	**2017**	**2018**		**2025**
Lifetime	1	2	3	…	10
Interest payments	15 000 000	14 058 819	13 023 520		2 219 255
Installments	9 411 809	10 352 990	11 388 289	…	22 192 554
Sum	**24 411 809**	**24 411 809**	**24 411 809**	**…**	**24 411 809**

Depreciation and salvage value

The depreciation is important in order allocate the costs of the assets to the period in which the asset is used. We assume the ship to a 40-year lifetime, and will be depreciated linearly.

The lightweight tonnage of an LNGC is the unit for the fixed weight of the empty built ship and is commonly used as a basis for determining the scrap value, which is important in the depreciation estimation. Lightweight tonnage is found using the following formula (Pearn, 2000):

$$Lightweight\ tonnage = Gross\ tonnage - Displacement$$

This gave us a lightweight tonnage of 35 000. The salvage value for an LNGC 40 years ahead is difficult to predict, but using an estimate at today's value at around 500 USD per ton, gives a scrap value of 17,5 million USD (Bondy, 2012).

Depreciation (in millions)		**First year of usage**			
Lifetime	0	1	2	…	40
Capex	250				
Yearly dep.		5,8125	5,8215		5,8125
Salvage value					17,5

As we can see from the table above, we get a yearly depreciation of 5,8125 million UDS.

8.5.2 Operating costs

Operating costs are non-trade-route specific costs and must be met before the vessel is clear for operations. Manning, basic insurance, repairs and maintenance are the most important operating cost elements (Thakur, 2011). These costs are the same for all three scenarios, and are assumed to be 15 000 USD per day (Höegh LNG, 2011).

8.5.3 Voyage costs

Voyage costs are the route specific costs. These consist of fuel consumption, port charges and canal tolls, where bunker/marine fuel is the main cost-item (Thakur, 2011). The amount of fuel a LNG vessel consumes is a function of speed, time and engine performance, haul design, cargo hold (i.e. laden or ballast) and weather conditions.

The vessel will, for the sake of simplicity, use the same speed and fuel consumption laden as in ballast for the round trips. BOG amount will be 0,15% of the cargo per day (Total, 2012). The LNG burned during transport can be calculated through this formula:

$$LNG\ burned\ during\ transport\ per\ day\ (m^3)$$
$$= LNG\ cargo\ volume\ (m^3) \times\ 0{,}15\% \times\ Number\ of\ days\ sailing\ \ (roundtrip)$$

Route Fuel consumed for one round trip	Hammerfest ↔ Milford Haven	Hammerfest ↔ Yokohama (Suez)	Hammerfest ↔ Yokohama (NSR)
LNG cargo volume (m^3)	165 000	165 000	165 000
BOG during transport (m^3)	1 633,5	13 563	9 207
Net LNG volume for sale (m^3)	**163 366,5**	**151 437**	**155 793**

As we can see from the table we have an initial LNG cargo volume and we have a net LNG volume that is what we can really sell at the price of the buyer. Since the carrier propulsion runs on LNG, the laden trip limits the tanks be emptied completely. In any case, the storage tanks on the carrier are often required to hold a minimum amount, or a heel. This is assumed to be in addition to the cargo value, making the total storage volume larger than the cargo volume. The LNG burned during transport will be the cost of transportation, and will be subtracted as a cost based on production cost from the LNG plant, which is 5,8 USD/mmBtu. To provide an example we will illustrate one of the routes (Hammerfest → Milford Haven → Hammerfest) transport costs:

$$BOG\ fuel = 6{,}6\ \times 5945 mmBtu \times\ 5{,}8 USD/mmBtu =\ 227\ 574{,}6\ USD$$

$$Pilot\ fuel = 6{,}6 \times 5{,}86 MT \times 650 USD/MT = 25\ 139{,}4\ USD$$

$$\boldsymbol{Roundtrip\ fuel\ cost = 252\ 714}$$

Port dues

Port dues and pilotage services are a part of the voyage-specific costs. The components can be complex and variable specific to berth or terminal used (Thakur, 2011). The charges are usually categorized by size.

In Milford Haven there are entry charges for all vessels based on gross tonnage, and are estimated to be around 15 000 GBP (MHPA, 2013a). Due to limited line of sight from the bridge of a LNG carrier and its safety measures, Milford Haven has implemented an exclusion zone and a 1 mile controlled zone in both directions of the pilots (as seen in Figure 8.1). A cost of 1 600 USD each way occurs to ensure that these zones are safe (Thakur, 2011). The pilotage and embarkation/disembarkation are roughly 12500 GBP each way (MHPA, 2013b). We assume an exchange rate of 0,62 USD/GBP for the whole valuation.

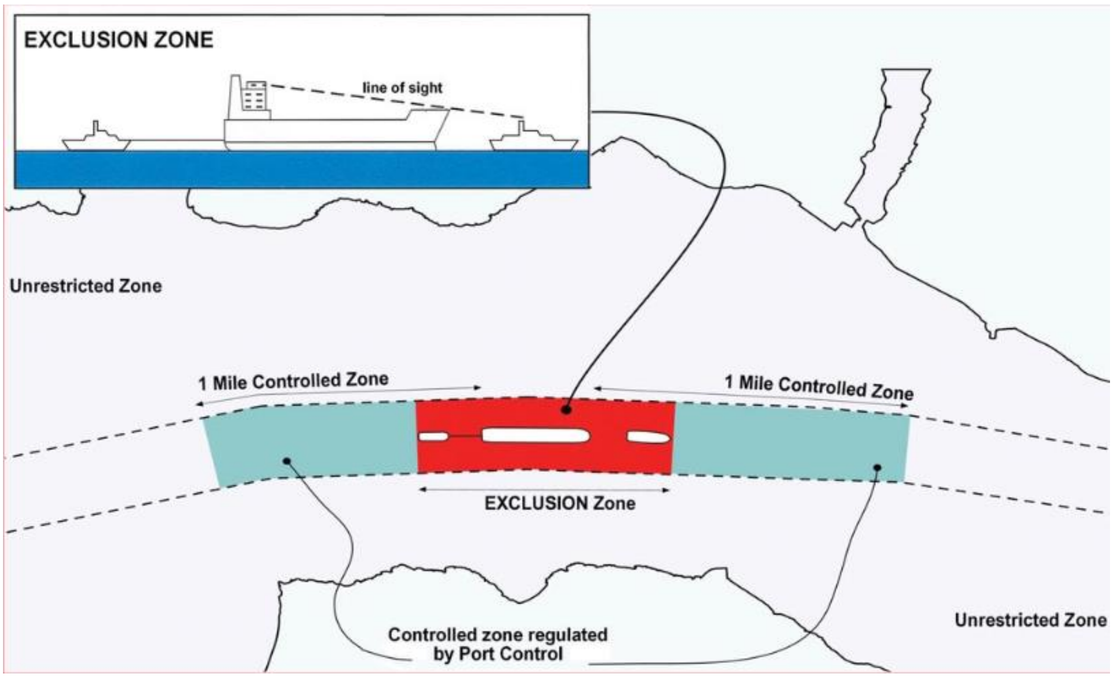


Figure 8.1: Illustration of exclusion and controlled zone (MHPA, 2013c)

The port dues and pilotage cost in Yokohama are extremely complex, and are therefore assumed to be the same as for Meridian Spirit docking in Futtsu, Japan (Laurent, 2013, referenced in Haeffele, 2013, pp. 119). The same goes for the port of Hammerfest. We assume an exchange rate of 0,16 USD/NOK.

Port dues	Hammerfest	Milford Haven	Yokohama
Port entry/berth hire	424 481	15 000	16 319
Pilotage etc.	746 486	25 000	73 480
Misc.	25 000	2 016	15 579
Total	**1 195 967 NOK**	**42 016 GBP**	**105 378 USD**
In USD	**191 355 USD**	**67 768 USD**	**105 378 USD**

NSR specific costs

There are some additional costs that have to be taken into consideration to get an accurate cost estimate for going through the NSR. Eastbound the tariff is 5 USD per ton of cargo, and westbound the vessel has to pay 2,5 USD per ton of displacement weight (Gunnarsson, 2013). This gives us the following tariffs for an eastbound NSR voyage:

$$\frac{165\ 000\ m^3}{2{,}222\ m^3/ton} \times\ 5\ \text{USD/ton}\ = 371\ 287\ \text{USD}$$

Westbound the 165 000 m^3 LNG ship has a displacement tonnage of 117 000 and gives us the following NSR tariffs:

$$117\ 000\ \text{tons}\ \times\ 2{,}5\ \text{USD/ton} = 292\ 500\ \text{USD}$$

In addition to NSR tariffs we also have an insurance premium for the transit at 160 000 USD and ice breaker assistance at 11 250 USD, both for each passage. According to Lauritzen (2013, referenced in Haeffele, 2013, pp. 53) it is also necessary to pay for NSR administration approval. This approval is 30 000 USD eastbound and 15 000 USD westbound.

Suez Canal specific costs

When the ship goes through the Suez Canal there are transfer fees for both eastbound and westbound passages. These fees amount to 5 USD per ton of cargo eastbound, and 5 USD per per ton of displacement going westbound (Gunnarsson, 2013). This is calculated the same way as the NSR tariff, giving us a transfer fee of 589 286 USD eastbound and 620 000 USD westbound. In addition to this, there is an insurance premium for Suez Canal transfers, at 65 000 USD for each passage (Haeffele, 2013).

Voyage costs, in USD	Hammerfest ↔ Milford Haven	Hammerfest ↔ Yokohama (Suez)	Hammerfest ↔ Yokohama (NSR)
Fuel costs	252 714	2 098 292	1 424 388
NSR tariff eastbound			371 287
NSR tariff westbound			292 500
NSR insurance costs			320 000
Ice breaker assistance			22 500
-			
Suez transfer eastbound		371 287	
Suez transfer westbound		585 000	
Suez insurance costs		130 000	
-			
Port dues Hammerfest	191 355	191 355	191 355
Port dues route specific	67 768	105 378	105 378
-			
Sum Voyage Costs	**511 837**	**3 481 312**	**2 727 408**

From the table above, we see that the savings is 753 913 USD for a round trip by going through the NSR instead of the Suez Canal. This is not as much as estimated by the Centre for High North Logistics mentioned earlier in the thesis, but that case was based on the same average speed through both passages (NSR and Suez Canal) and a charter rate rather than ownership of an LNG ship. Even though the costs saved are not as big, the important thing to remember is that the time saved is 17,6 days, which is quite a lot.

8.5.4 Costs not included

Access to regasification capacity in the defined ports is likely to be constrained, as the holders probably would seek to capture some of the benefits of delivering spot cargoes by raising rates for terminal access. However, we assume that there is no regasification rent. (Similarly to Free On Board (FOB) sales.) In addition, the Norwegian producer is also assumed to be well-established in the market, meaning that brokerage commissions are excluded from our total costs.

8.6 Analysis of Case 1

Case 1 is based on a forward contract to Milford Haven in UK, with a price of 8,5 USD/mmBtu throughout the lifetime of the LNGC. The loan repayments reduce the cash flows only the first 10 years. The following years are equal, except for the last one where the salvage value is included:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			**Delivery of vessel**							
Forward contract										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven										
Sales volume			113 673 263	113 673 263		113 673 263	113 673 263		113 673 263	113 673 263
Sales price			8,50	8,50		8,50	8,50		8,50	8,50
Revenues			**966 222 737**	**966 222 737**		**966 222 737**	**966 222 737**		**966 222 737**	**966 222 737**
OPEX Snøhvit	5,8 USD/mmBtu		665 897 310	665 897 310		665 897 310	665 897 310		665 897 310	665 897 310
Margin after OPEX			300 325 427	300 325 427		300 325 427	300 325 427		300 325 427	300 325 427
Special taxes	0,51		153 165 968	153 165 968		153 165 968	153 165 968		153 165 968	153 165 968
Margin after special taxes			**147 159 459**	**147 159 459**		**147 159 459**	**147 159 459**		**147 159 459**	**147 159 459**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			10 000 000	9 204 954		1 233 377				
Salvage value (year 40)	17 500 000									
Fuel costs			7 320 683	7 320 683		7 320 683	7 320 683		7 320 683	7 320 683
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			7 506 341	7 506 341		7 506 341	7 506 341		7 506 341	7 506 341
Sum shipping costs			**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**
Profit			111 044 935	111 839 981		119 811 558	121 044 935		121 044 935	121 044 935
Taxes			29 982 132	30 196 795		32 349 121	32 682 132		32 682 132	32 682 132
Profit after taxes			**81 062 803**	**81 643 186**		**87 462 437**	**88 362 803**		**88 362 803**	**88 362 803**
Loan payments			15 900 915	16 695 961		24 667 538				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**70 974 388**	**70 759 725**		**68 607 399**	**94 175 303**		**94 175 303**	**106 950 303**
NPV	**1 116 774 900**									
IRR	**0,2577**									

The investment in Case 1 should considered to be very profitable. From the spreadsheet printout (also found in Appendix 2) we can see that the return on capital is enormous, the NPV is 4,46 times bigger than the initial investment. The payback period, the time required to recover the cost of the asset is 5 years. This is a positive argument for the undertaking of the project considering that the lifetime of the asset is 40 years.

Using the measurement of NPV and IRR we answer the sub-research question: *What is the value of investing in a ship selling LNG on a long-term contract to the European market for a Norwegian producer?* The answer is $NPV = 1\,116\,774\,900$, with an $IRR_{Case\ 1} = 25{,}77\%$ which exceeds the hurdle rate of 4,7672%.

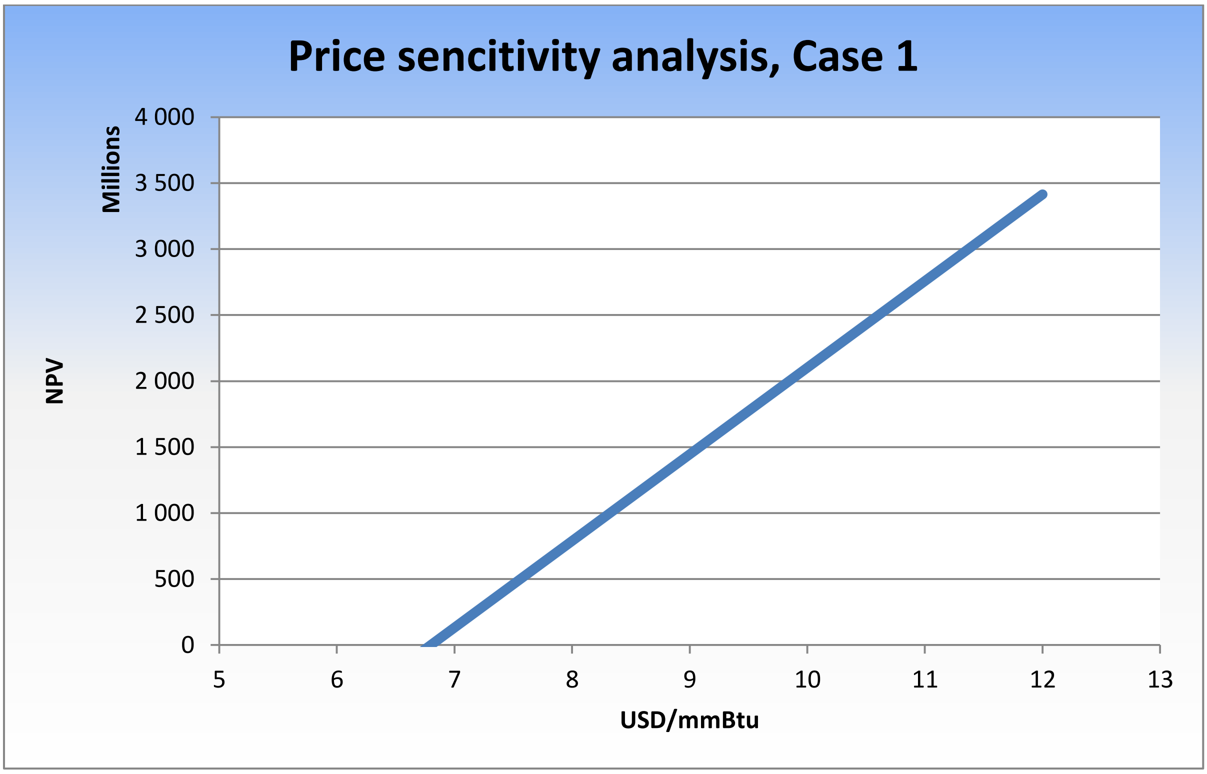


Figure 8.2: Price sensitivity analysis, Case 1

If we in “the negotiations” of a forward price had agreed upon a higher price, e.g. 9 USD/mmBtu, the NPV of the investment would have been over 29% larger. That such a minor change in price amounts to a significant NPV increase, really demonstrates the huge volumes of gas that is transported and how sensitive the NPV is to price changes. The indifference curve (Figure 8.3) for Case 1 shows us how affected the NPV is to changes in the rate of return.

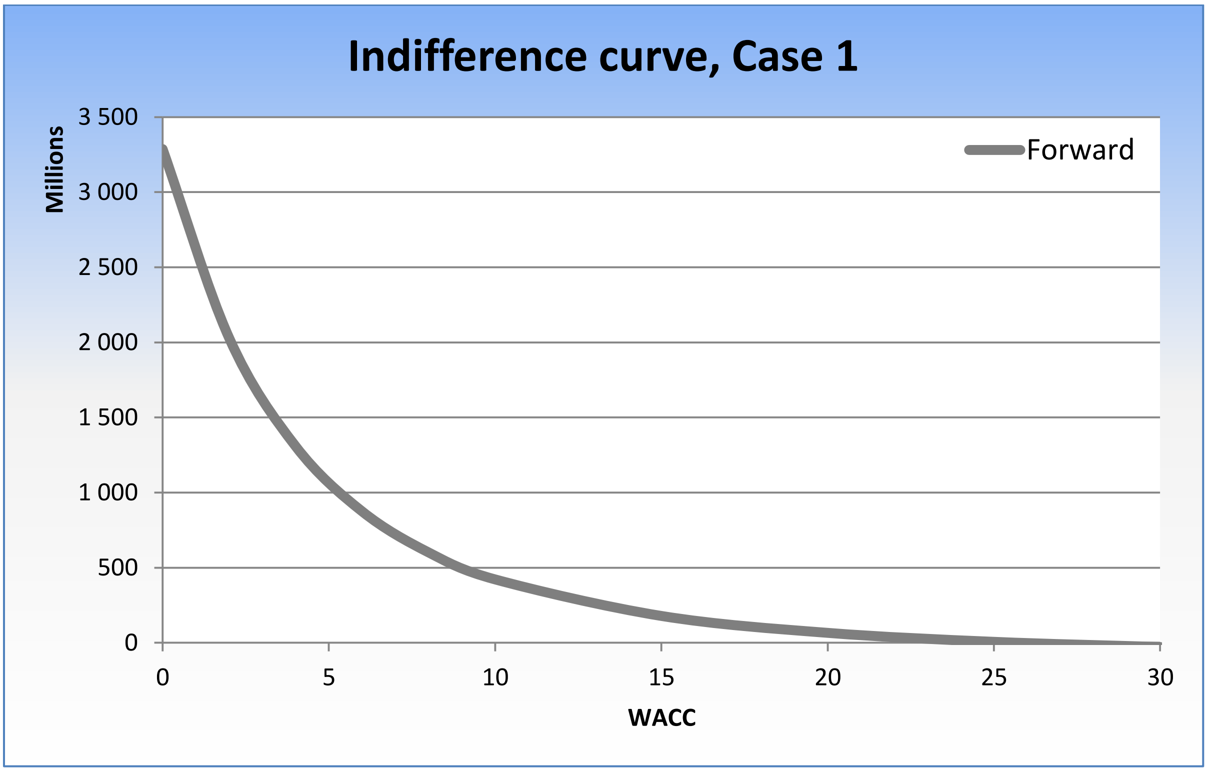


Figure 8.3: Indifference curve, Case 1

As we can see from the graph above the WACC have to be above 25% in order for the NPV of the project to be negative, which corresponds with the IRR of 25,77%

8.7 Analysis of Case 2

In Case 2 the LNGC is selling LNG on spot to Milford Haven, UK. Every one of the three price scenarios has monthly changes, except for the medium scenarios. We have already assumed that the vessel is ready to use in the beginning of 2016, and the minor monthly changes in the medium scenario happens before that time. In the two other price scenarios the price increases/decreases until it stabilizes in 2024, as illustrated in Figure 7.20. Hence, to calculate the annual revenues in all spot cases the following formula was used:

$$Sales\ volume\ per\ month = \frac{Round\ trips\ per\ year\ \times sales\ volume\ per\ round\ trip}{12}$$

$$Annual\ revenue = (Sales\ volume\ per\ month \times monthly\ price)\ \times 12$$

What is the value of investing in a ship selling LNG on spot or short-term contracts to the European market for a Norwegian producer? Firstly, the investment in Case 2 is highly profitable. The NPV is positive in all three price scenarios, and ranging between 693 and 3179 million USD, low to high respectively. The spreadsheets for Case 2 can be found in Appendix 3. The payback period in Case 2 is even shorter than for Case 1. Already after two years of usage in all three price scenarios, the vessel has recovered its cost.

Case 2	Scenario	NPV	IRR
	Low	693 million USD	40,23%
	Medium	1 588 million USD	53,72%
	High	3 179 million USD	71,01%

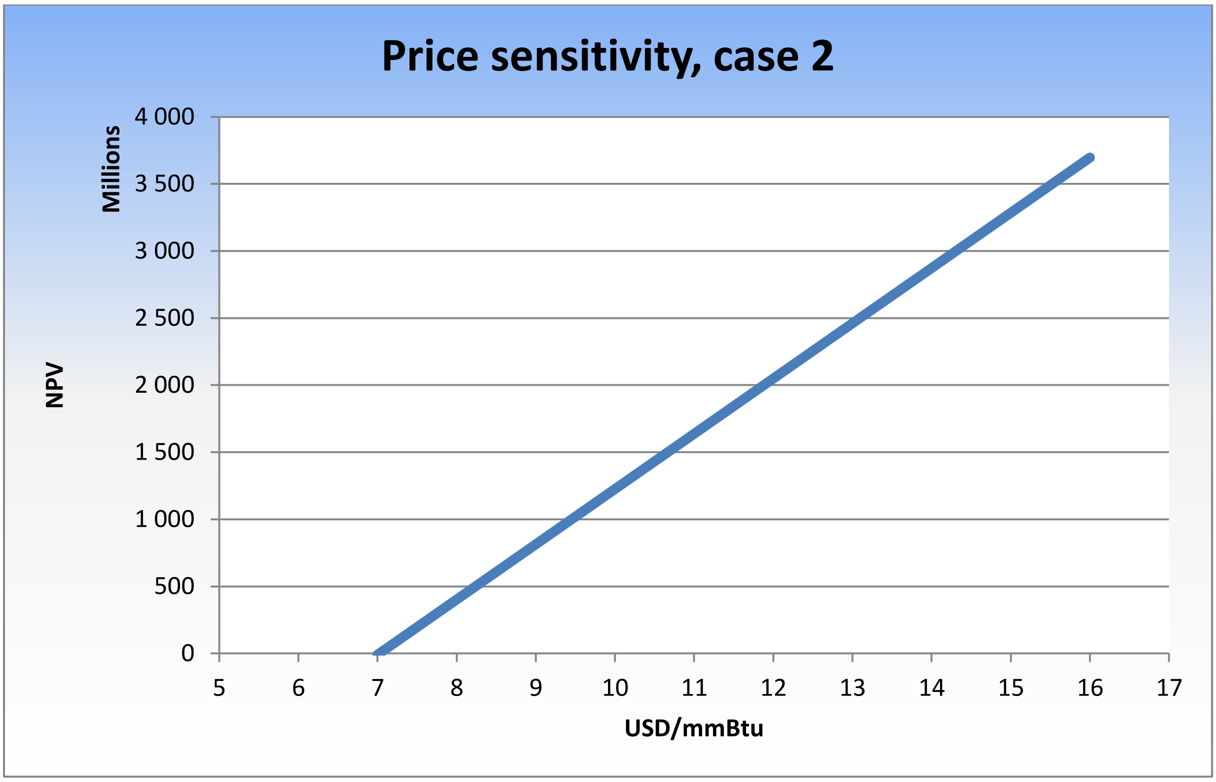


Figure 8.4: Price sensitivity analysis, Case 2

The break-even price in Case 2 is 7,02 USD/mmBtu. As we can see from the figure above, the NPV of the project in a high risk case is very sensitive to changes in price. Even a change from 9 to 8 USD/mmBtu reduces the NPV over 50%. This demonstrates the high risk, but also the high potential profit of investing in a LNG ship with spot trade. This also applies to the other high risk cases, with their respective numbers, as costs and number of annual round trips differ.

The NPV under Case 1 is more predictable because the forward contract adds certainty to the cash flows of the project. In Case 2 the NPV is based on uncertain input data (prices), which means the cash flows are perceived as unsafe. However, it is important to remember that the cash flows in all the spot cases are based on a higher rate of return because of higher risk.

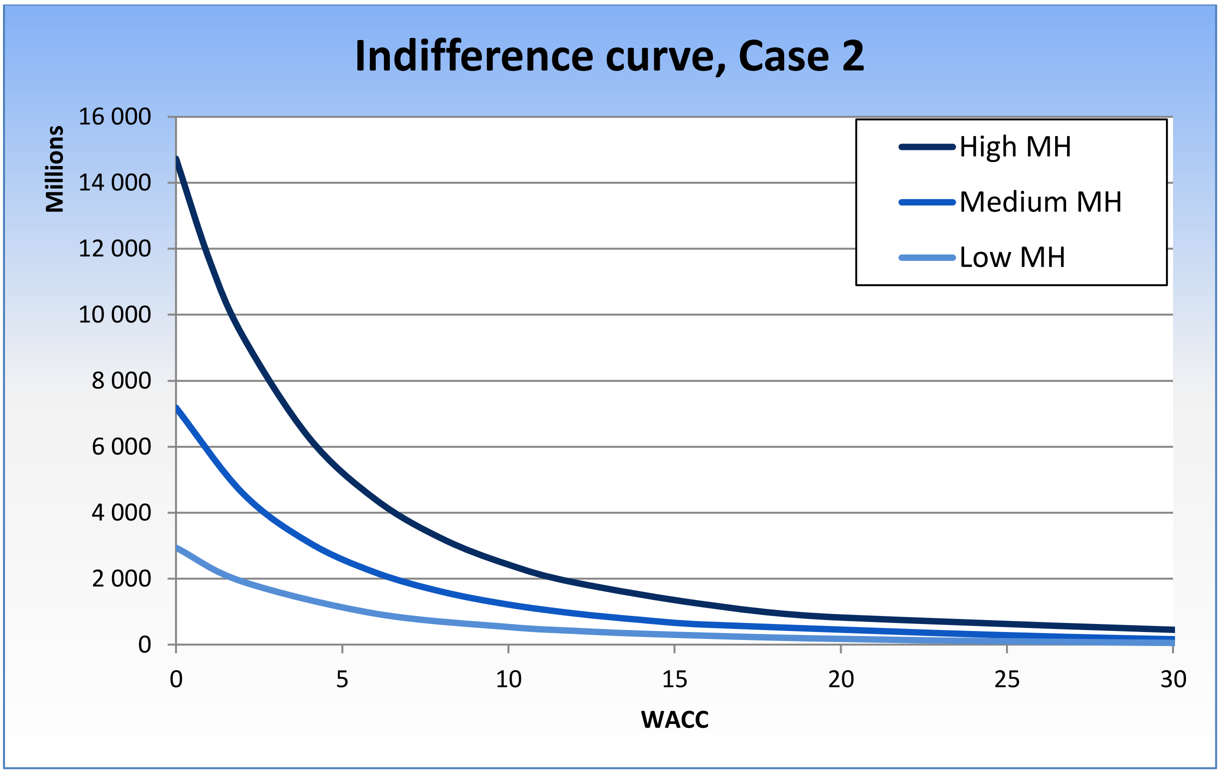


Figure 8.5: Indifference curve, Case 2

Figure 8.5 shows the indifference curves in Case 2, given the three price scenarios. (Milford Haven is referred to as "MH".) There is a very big difference between the NPVs in the three price scenarios, which again stresses how sensitive the NPV of the project is to price changes. Yet, the project in Case 2 has a lot of room for uncertainty as the IRR in the low price scenario is 40,23 %, and even higher for the two other scenarios.

8.8 Analysis of Case 3

The same formula to calculate annual revenue was applied in the analysis of Case 3. In this case we investigated the value using the NSR and the Suez Canal as shipping routes to the Japanese market, in order to answer the sub research question: *What is the value of investing in a ship selling LNG on spot or short-term contracts to the Japanese market for a Norwegian producer?*

Case 3	Scenario	NPV	IRR
Suez only	Low	-125 million USD	1,68%
	Medium	176 million USD	13,43%
	High	540 million USD	22,25%
Suez and NSR	Low	-65 million USD	4,73%
	Medium	288 million USD	16,83%
	High	714 million USD	26,61%

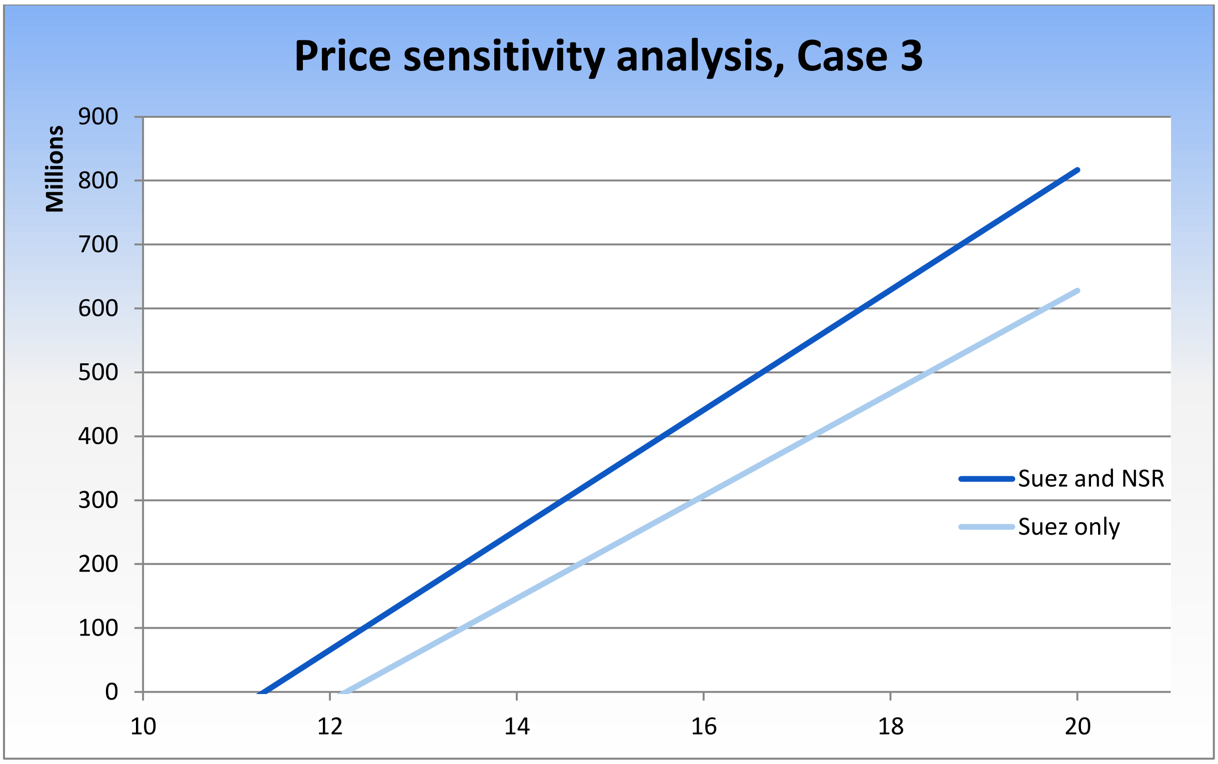


Figure 8.6: Price sensitivity analysis, Case 3

First, we looked at only using the Suez Canal. This gave a NPV ranging between -125 and 540 million USD, with a break-even price of 12,18 USD/mmBtu.

However, utilizing the NSR during the summer months offers a much greater value. The reason for this is the costs and timed saved, which is 753 913 USD and 17,6 days per round trip when using the NSR. The NPV for this alternative ranged between -7 and 714 million USD, whereas the break-even price was 11,3 USD/mmBtu. By comparing the curves for NPV relative to a constant price in Figure 8.7, we see that using the NSR yields an increasingly higher NPV with higher prices than just using the Suez Canal. The spreadsheets for Case 3 are shown in Appendix 4. The difference between the alternatives is also reflected in the payback period. The Suez only alternative is paid back in 2028 and 2020, given medium and high price scenario. Of course, in the low price scenario the Suez alternative will never pay back the initial investment, as the NPV is negative. Combining the NSR and the Suez Canal is paid back in 2022 and 2019, medium and high respectively. In the low price scenario also this alternative will never be profitable.

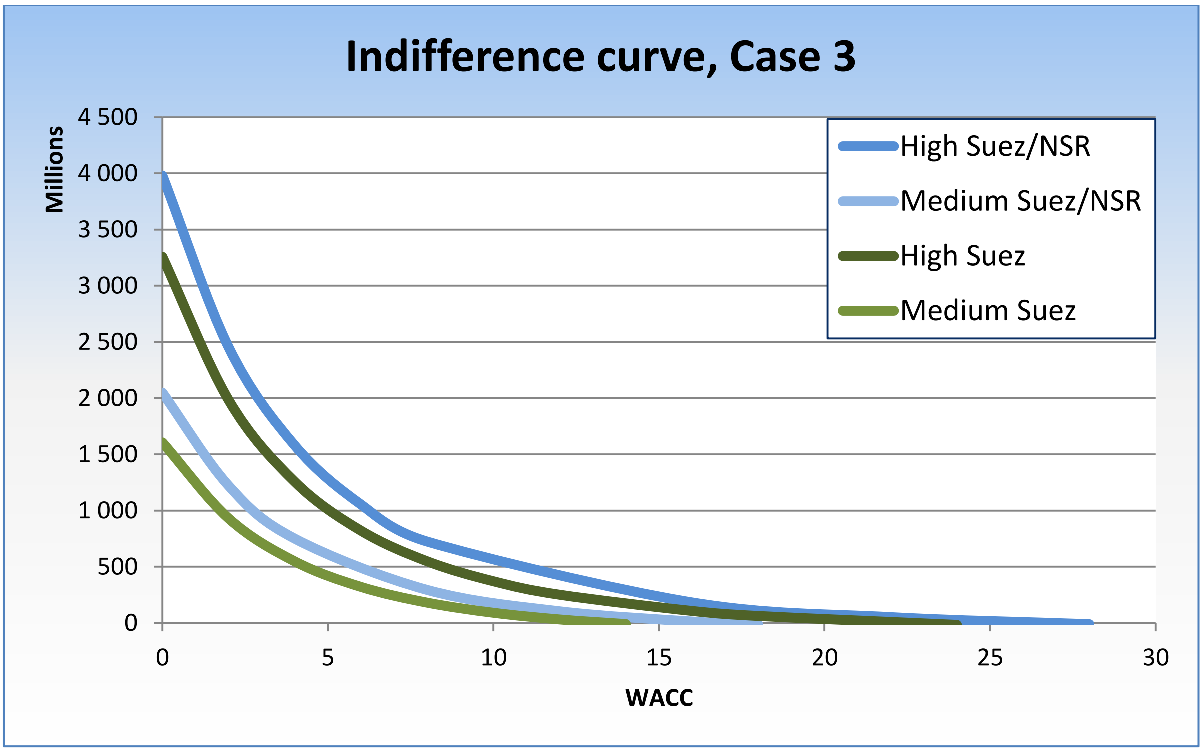


Figure 8.7: Indifference curve, Case 3

Figure 8.7 shows the indifference curves for high and medium price scenario for the two alternatives in Case 3. Low price scenarios for both alternatives are not included because the NPVs were negative. The curves show that there is not as much room for uncertainty as in Case 2. Hence, a risk averse investor would prefer Case 2 over 3, because it offers both a higher return and higher stability.

8.9 Analysis of Case 4

In Case 4 we looked at sales to Japan through NSR during the summer, and sales to UK the rest of the year. From the assumptions made about the available usage time of NSR, we have two options: to use the NSR for 3 round trips, or to use it for 3,5 round trips and traveling back via the Suez Canal. The last option of these two gave a significantly lower NPV than the first option. This can be explained by the increased costs and traveling time, which is better used between Hammerfest and Milford Haven. This is further supported by looking at the NPVs for Case 2 and 3.

Case 4	Scenario	NPV	IRR
	Low	601 million USD	38,69%
	Medium	1 061 million USD	39,63%
	High	2 739 million USD	67,05%

What is the value of investing in a ship selling LNG on spot or short-term contracts to the European and/or Japanese market for a Norwegian producer? The best option in Case 4 gave a NPV ranging between 601 and 2739 million USD, and a brake-even price of 7,53 USD/mmBtu. The NPV is positive in all three price scenarios, and the spreadsheets can be found in Appendix 5

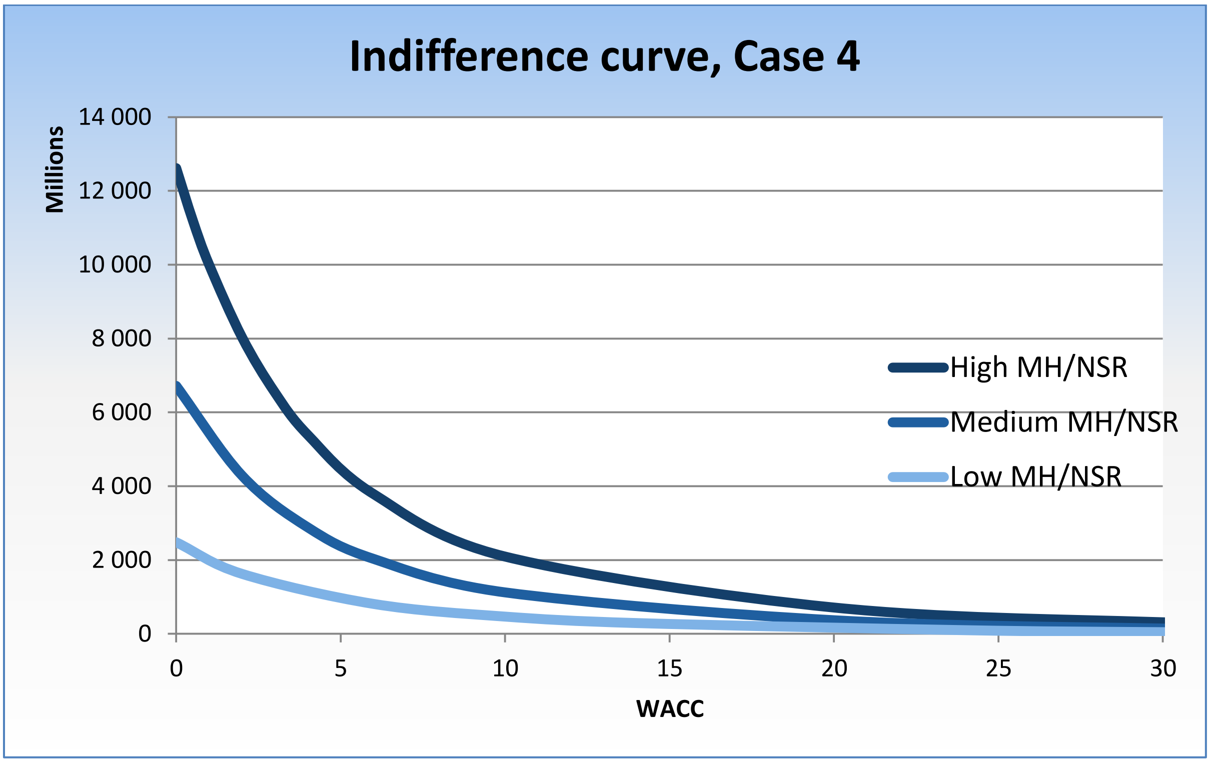


Figure 8.8: Indifference curve, Case 4

In Figure 8.8 we can see that the indifference curves are somewhere in the middle of those found in Case 2 and 3, and seem quite logical as Case 4 is a combination of them.

9 Conclusion

In this chapter we will compare the analyses of the cases in order to answer the main research question. In addition, an evaluation of the research will be presented, including its limitations and suggestions to further research.

9.1 Case comparisons

In Figure 9.1 we have put all the cases and their NPVs for all three different price scenarios, including the NPV for the forward contract. We can see that there is a very significant difference in NPV, especially between the cases towards the UK market and only towards the Japan market. The two cases involving selling to Milford Haven on spot, clearly has the highest value. It is interesting to see that even selling with a forward contract to Milford Haven gives a higher NPV than selling only to Japan on spot, in all three price scenarios. In addition, Case 1 has no price risk! We can also see that in the low price scenario selling to Japan in Case 3 is not profitable.

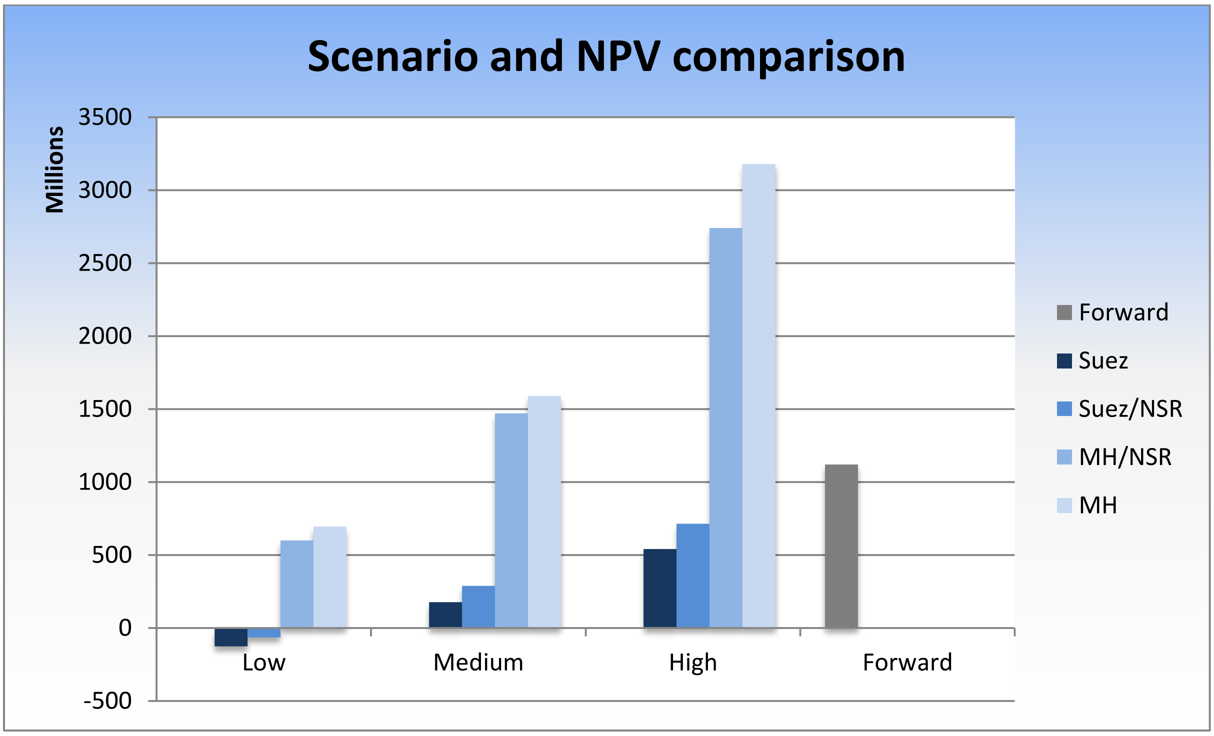


Figure 9.1: Comparison of NPVs with different price scenarios

Is there an added value of having the possibility to export LNG with spot or short-term contracts versus having a secure long-term contract towards Europe?

From what we have discussed so far about selling only to the Japanese market, as done in case 3, there is no value added. The main reason for this is the time difference. By delivering to Milford Haven the LNGC can almost do 5 round trips, compared to the time it takes for a round trip to Yokohama. Even when going through the timesaving NSR, the ship can do almost 3,5 trips more. In other words the Milford Haven route is much more effective in terms of transport volume, and this has a strong time effect on the NPV for both Case 1 and 2. When further evaluating the NPV, we also see that the different financing structure and cost of capital is affecting it both directly and indirectly. Firstly, the low and high risk cases discounts the cash flows with distinctive rates. Secondly, the interest payments are not the same.

What is the increased value of investing in a ship selling LNG on spot instead of a long-term contract for a Norwegian producer?

The main research question was formulated with "what is the *increased* value". This obliges us to compare the two distribution alternatives: spot sales and long-term contract sales, which is represented by delta (Δ) NPV:

$$\Delta NPV = NPV_{Spot} - NPV_{FW}$$

where, NPV_{Spot} is the NPV calculated for the high risk cases, and NPV_{FW} for the low risk case. In figure 9.2 every Δ NPV is calculated.

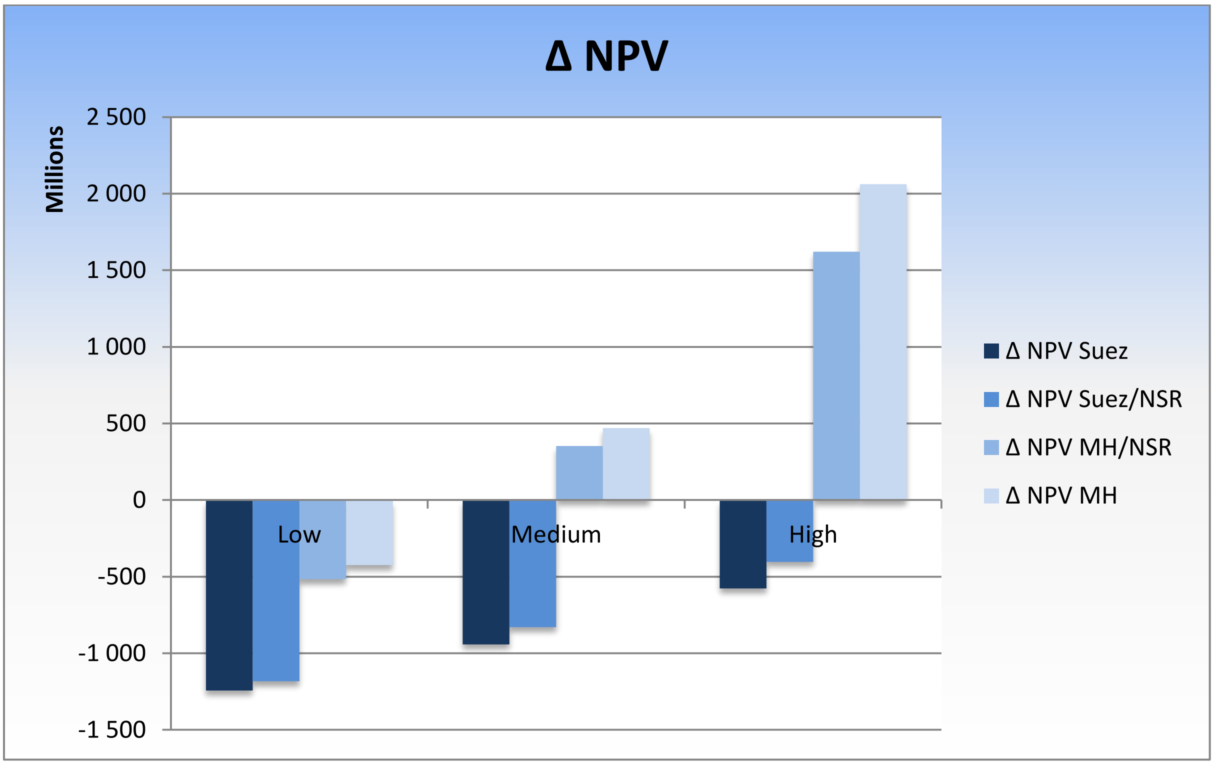


Figure 9.2: Delta NPV

As mentioned above, we can confirm from figure 9.2 that there is no value added selling when on spot to only Japan, instead of using a forward contract to UK. This holds in all the three price scenarios. The NPV method values money higher today, than money in the future. Case 2 gives a higher Δ NPV than Case 3 and 4, because the value is created in a shorter period of time, making it more valuable today. We also see that any case or alternative involving selling to Milford Haven, with medium or high price scenario, yield the highest Δ NPVs. Of these, Case 2 is the "greatest". Therefore, to answer the main research question we compare the Δ NPV between Case 1 and Case 2. The low price scenario towards Milford Haven on spot yields a negative Δ NPV of -423 million USD, which indicates that for an investor with a pessimistic view on the future price, the forward contract is the best alternative. In the medium price scenario the Δ NPV is 471 million USD, and in the high price scenario it is a massive 2 062 million USD, which suggests that taking risk can pay off massively.

9.1.1 UTILIZING FREE DESTINATION SHIPPING

With an investment in a ship for free destination, there is no obligation to ship towards one particular buyer. In an inefficient market with price differences, this can be seen as a natural hedge. Since none of the cargo is hedged for price fluctuations there is a potential to take advantage of the market offering the highest price. Comparing the profitability of sending either to the European or the Japanese market, the time and volume aspect has to be taken into consideration. By shipping towards Milford Haven one can sell a larger volume in a shorter period compared to Yokohama. In order to account for these factors, the NPV for case 2 and case 3 with different average prices over the lifetime of the LNGC was put into a chart.

Figure 9.3: Free destination analysis

As we can see from the figure above, if the price equals to 8 USD/mmBtu in the European market, then the price has to be above 15,5 USD/mmBtu for it to be more profitable to ship towards the Japan market. Then, if the price is 11 USD/mmBtu in the European market, then the price has to be almost 29 USD/mmBtu in the Japan market. This illustrates how much the time and volume affects the NPV. Nevertheless, if the European market were to take a downturn, the natural hedge proffers Japan as an alternative.

Under our assumptions, we do not see that Norway as a supplier of natural gas would miss out on economic values by not selling on spot to the Japanese/Asian market. We do however see that if the price difference would exceed further than the level of our calculations, or under an economic downturn in Europe, the Japanese market would be very attractive. It is very important to state that these calculations are based on certain assumptions. If for instance there was a volume restriction on LNG cargos from the Snøhvit field, the case valuations could be different.

9.2 Evaluation of the research

9.2.1 Limitations

A limitation that should be considered in this thesis is the assumption of continuous supply of LNG from the plant. In a portfolio of vessels, an additional vessel picking up supply would require further extensive planning. If the production of LNG is thought to be nearly linear (either on or off), pick-ups should happen with the same consistency. By that logic, vessels should be assigned to a voyage plan going by other ports and plants, rather than just one route, e.g. Hammerfest-Yokohama-Hammerfest. In that way the vessels would come regularly by Hammerfest. If not done, some of the vessels would come with short intervals, while others just once in a while, and possibly arriving to load LNG at the same time. Of course, this is highly dependent on the production and storage capacity of the plant. In addition, the vessels could be used to load LNG from other plants in the portfolio of the Norwegian producer.

Lastly, the Snøhvit field has a limited amount of gas reserves. Therefore, assuming that this vessel in the investment analysis comes to pick up cargoes regularly, in addition to those already supplying long-term contracts, is a simplification. Nonetheless, this was necessary to isolate the analysis to a Norwegian standpoint. In Case 2, where the most LNG is picked up, the volumes are substantial, but do not exceed the annual production. However, it is likely that it would have affected the already existing vessel portfolio. Our suggestion to further research is to investigate the value of introducing a vessel solely for spot trade in a vessel portfolio. Alternatively or including, finding the value of increasing annual production of a LNG plant e.g. the Melkøya plant (to stay in the Norwegian context). If the method of discounted cash flows is used, both suggestions will most likely observe the same time effect as seen in this study, thus get increased values.

9.2.2 CONTRIBUTION

The choice of method helped us answer the main research question, and we consider our conclusion to be reasonable. By comparing the analyses of the cases we were able to see a value difference for the two different usages of a LNGC. However, we can surely assume that the industry already knows this since there has been and increasing trend of spot and short-term trade. Although this thesis might not be a contribution to new knowledge, we have by doing the research formalized it. Consequently, we now have a basis to describe the construct of value difference between investing in a LNGC for spot-trade and a long-term agreement.

9.3 SUMMING UP

In the strategic analysis in Chapter 6, we saw that there is a potential for profitability in the industry as there were limited threats from market forces. The investment analysis confirmed that there is a high potential value in exporting LNG, using both long-term agreements and spot trade. Price risk is a very important factor in the LNG risk management. The regional prices drive the volumes to a certain degree, but we have found that in today's value, distance to the market is just as, or even more important. Investing in a LNGC used for spot trade will most likely be rewarded as the potential compensation for taking a higher risk is significant. Spot trade is a very relevant topic in the LNG industry and in the discussion about risk appetite. Movement away from long-term contracts caused by price spread stands in contrast to the risk aversion seen in multinational oil and gas companies. Even though an investment analysis takes risk and reward into consideration, a non-hedged position will never guarantee an investment. Ultimately, such an investment depends on the risk aversion of the Norwegian producer.

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APPENDIX 1

Conversion factors (IGU, 2014):

Multiply by

	Tonnes LNG	cm LNG	cm gas	cf gas	mmBtu	boe
Tonnes LNG		2.222	1,300	45,909	53.38	9.203
cm LNG	0.450		585	20,659	24.02	4.141
cm gas	7.692×10^{4}	0.0017		35.31	0.0411	0.0071
cf gas	2.178×10^{5}	4.8×10^{-5}	0.0283		0.0012	2.005×10^{-4}
mmBtu	0.0187	0.0416	24.36	860.1		0.1724
boe	0.1087	0.2415	141.3	4,989	5.8	

APPENDIX 2

Cash flows in Case 1, forward contract to Milford Haven

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Forward contract			1	2		10	11		39	40
Melkøya ↔ Milford Haven										
Sales volume			113 673 263	113 673 263		113 673 263	113 673 263		113 673 263	113 673 263
Sales price			8,50	8,50		8,50	8,50		8,50	8,50
Revenues			**966 222 737**	**966 222 737**		**966 222 737**	**966 222 737**		**966 222 737**	**966 222 737**
OPEX Snøhvit	5,8 USD/mmBtu		665 897 310	665 897 310		665 897 310	665 897 310		665 897 310	665 897 310
Margin after OPEX			300 325 427	300 325 427		300 325 427	300 325 427		300 325 427	300 325 427
Special taxes	0,51		153 165 968	153 165 968		153 165 968	153 165 968		153 165 968	153 165 968
Margin after special taxes			**147 159 459**	**147 159 459**		**147 159 459**	**147 159 459**		**147 159 459**	**147 159 459**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			10 000 000	9 204 954		1 233 377				
Salvage value (year 40)	17 500 000									
Fuel costs			7 320 683	7 320 683		7 320 683	7 320 683		7 320 683	7 320 683
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			7 506 341	7 506 341		7 506 341	7 506 341		7 506 341	7 506 341
Sum shipping costs			**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**
Profit			111 044 935	111 839 981		119 811 558	121 044 935		121 044 935	121 044 935
Taxes			29 982 132	30 196 795		32 349 121	32 682 132		32 682 132	32 682 132
Profit after taxes			**81 062 803**	**81 643 186**		**87 462 437**	**88 362 803**		**88 362 803**	**88 362 803**
Loan payments			15 900 915	16 695 961		24 667 538				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**70 974 388**	**70 759 725**		**68 607 399**	**94 175 303**		**94 175 303**	**106 950 303**
NPV	**1 116 774 900**									
IRR	**0,2577**									

(On all cash flows in all cases the salvage value is added in year 2055 as an income minus 27% taxes)

APPENDIX 3

Case 2:

Cash flows in case 2, spot to Milford Haven - Low price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven										
Sales volume			113 673 263	113 673 263		113 673 263	113 673 263		113 673 263	113 673 263
Sales price			10,29	10,02		8,00	8,00		8,00	8,00
Revenues			**1 169 271 603**	**1 138 579 822**		**909 386 105**	**909 386 105**		**909 386 105**	**909 386 105**
OPEX Snøhvit	5,8 USD/mmBtu		665 897 310	665 897 310		665 897 310	665 897 310		665 897 310	665 897 310
Margin after OPEX			503 374 293	472 682 512		243 488 796	243 488 796		243 488 796	243 488 796
Special taxes	0,51		256 720 890	241 068 081		124 179 286	124 179 286		124 179 286	124 179 286
Margin after special taxes			**246 653 404**	**231 614 431**		**119 309 510**	**119 309 510**		**119 309 510**	**119 309 510**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			7 320 683	7 320 683		7 320 683	7 320 683		7 320 683	7 320 683
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			7 506 341	7 506 341		7 506 341	7 506 341		7 506 341	7 506 341
Sum shipping costs			**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**
Profit			205 538 880	191 441 088		90 975 731	93 194 986		93 194 986	93 194 986
Taxes			55 495 497	51 689 094		24 563 447	25 162 646		25 162 646	25 162 646
Profit after taxes			**150 043 382**	**139 751 994**		**66 412 283**	**68 032 339**		**68 032 339**	**68 032 339**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**146 444 073**	**135 211 504**		**50 032 229**	**73 844 839**		**73 844 839**	**86 619 839**
NPV	**693 456 728**									
IRR	**0,4023**									

The sales price in the all spreadsheets is the mean price for the whole year. Therefore, the sum of multiplying volume and price for each year is not accurate. (We refer to Chaper 8.7.)

Cash flows in case 2, spot to Milford Haven - Medium price scenario:

Year	**2014**	**2015**	**2016**	**2017**	**…**	**2025**	**2026**	**…**	**2054**	**2055**
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven										
Sales volume			113 673 264	113 673 264		113 673 264	113 673 264		113 673 264	113 673 264
Sales price			10,88	10,88		10,88	10,88		10,88	10,88
Revenues			**1 236 765 103**	**1 236 765 103**		**1 236 765 103**	**1 236 765 103**		**1 236 765 103**	**1 236 765 103**
OPEX Snøhvit	5,8 USD/mmBtu		665 897 310	665 897 310		665 897 310	665 897 310		665 897 310	665 897 310
Margin after OPEX			570 867 793	570 867 793		570 867 793	570 867 793		570 867 793	570 867 793
Special taxes	0,51		291 142 575	291 142 575		291 142 575	291 142 575		291 142 575	291 142 575
Margin after special taxes			**279 725 219**	**279 725 219**		**279 725 219**	**279 725 219**		**279 725 219**	**279 725 219**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			7 320 683	7 320 683		7 320 683	7 320 683		7 320 683	7 320 683
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			7 506 341	7 506 341		7 506 341	7 506 341		7 506 341	7 506 341
Sum shipping costs			**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**
Profit			238 610 695	239 551 876		251 391 440	253 610 695		253 610 695	253 610 695
Taxes			64 424 888	64 679 006		67 875 689	68 474 888		68 474 888	68 474 888
Profit after taxes			**174 185 807**	**174 872 869**		**183 515 751**	**185 135 807**		**185 135 807**	**185 135 807**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**170 586 498**	**170 332 379**		**167 135 697**	**190 948 307**		**190 948 307**	**203 723 307**
NPV	**1 587 979 430**									
IRR	**0,5372**									

Cash flows in case 2, spot to Milford Haven - High price scenario:

Year	**2014**	**2015**	**2016**	**2017**	**…**	**2025**	**2026**	**…**	**2054**	**2055**
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven										
Sales volume			113 673 264	113 673 264		113 673 264	113 673 264		113 673 264	113 673 264
Sales price			11,94	12,42		16,00	16,00		16,00	16,00
Revenues			**1 357 258 762**	**1 411 821 928**		**1 818 772 210**	**1 818 772 210**		**1 818 772 210**	**1 818 772 210**
OPEX Snøhvit	5,8 USD/mmBtu		665 897 310	665 897 310		665 897 310	665 897 310		665 897 310	665 897 310
Margin after OPEX			691 361 452	745 924 619		1 152 874 901	1 152 874 901		1 152 874 901	1 152 874 901
Special taxes	0,51		352 594 341	380 421 555		587 966 199	587 966 199		587 966 199	587 966 199
Margin after special taxes			**338 767 112**	**365 503 063**		**564 908 701**	**564 908 701**		**564 908 701**	**564 908 701**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			7 320 683	7 320 683		7 320 683	7 320 683		7 320 683	7 320 683
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			7 506 341	7 506 341		7 506 341	7 506 341		7 506 341	7 506 341
Sum shipping costs			**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**		**20 302 024**	**20 302 024**
Profit			297 652 587	325 329 720		536 574 922	538 794 177		538 794 177	538 794 177
Taxes			80 366 199	87 839 024		144 875 229	145 474 428		145 474 428	145 474 428
Profit after taxes			**217 286 389**	**237 490 696**		**391 699 693**	**393 319 749**		**393 319 749**	**393 319 749**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**213 687 080**	**232 950 206**		**375 319 639**	**399 132 249**		**399 132 249**	**411 907 249**
NPV	**3 179 205 553**									
IRR	**0,7101**									

APPENDIX 4

Case 3:

Cash flows in case 3, spot to Yokohama (Suez Canal only) - Low price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez only)										
Sales volume			22 151 136	22 151 136		22 151 136	22 151 136		22 151 136	22 151 136
Sales price			14,19	13,58		9,00	9,00		9,00	9,00
Revenues			**314 302 514**	**300 722 099**		**199 360 183**	**199 360 183**		**199 360 183**	**199 360 183**
OPEX Snøhvit	5,8 USD/mmBtu		137 998 456	137 998 456		137 998 456	137 998 456		137 998 456	137 998 456
Margin after OPEX			176 304 059	162 723 643		61 361 727	61 361 727		61 361 727	61 361 727
Special taxes	0,51		89 915 070	82 989 058		31 294 481	31 294 481		31 294 481	31 294 481
Margin after special taxes			**86 388 989**	**79 734 585**		**30 067 246**	**30 067 246**		**30 067 246**	**30 067 246**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			45 694 978	39 981 755		2 153 980	4 373 235		4 373 235	4 373 235
Taxes			12 337 644	10 795 074		581 575	1 180 774		1 180 774	1 180 774
Profit after taxes			**33 357 334**	**29 186 681**		**1 572 406**	**3 192 462**		**3 192 462**	**3 192 462**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**29 758 025**	**24 646 191**		**-14 807 648**	**9 004 962**		**9 004 962**	**21 779 962**
NPV	**-125 929 377**									
IRR	**0,0168**									

The sales price in the all spreadsheets is the mean price for the whole year. Therefore, the sum of multiplying volume and price for each year is not accurate. (We refer to Chaper 8.7.)

Cash flows in case 3, spot to Yokohama (Suez Canal only) - Medium price scenario:

Year	**2014**	**2015**	**2016**	**2017**	**…**	**2025**	**2026**	**…**	**2054**	**2055**
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez only)										
Sales volume			22 151 136	22 151 136		22 151 136	22 151 136		22 151 136	22 151 136
Sales price			14,37	14,37		14,37	14,37		14,37	14,37
Revenues			**318 311 758**	**318 311 758**		**318 311 758**	**318 311 758**		**318 311 758**	**318 311 758**
OPEX Snøhvit	5,8 USD/mmBtu		137 998 456	137 998 456		137 998 456	137 998 456		137 998 456	137 998 456
Margin after OPEX			180 313 303	180 313 303		180 313 303	180 313 303		180 313 303	180 313 303
Special taxes	0,51		91 959 784	91 959 784		91 959 784	91 959 784		91 959 784	91 959 784
Margin after special taxes			**88 353 518**	**88 353 518**		**88 353 518**	**88 353 518**		**88 353 518**	**88 353 518**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			47 659 507	48 600 688		60 440 252	62 659 507		62 659 507	62 659 507
Taxes			12 868 067	13 122 186		16 318 868	16 918 067		16 918 067	16 918 067
Profit after taxes			**34 791 440**	**35 478 502**		**44 121 384**	**45 741 440**		**45 741 440**	**45 741 440**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**31 192 131**	**30 938 012**		**27 741 330**	**51 553 940**		**51 553 940**	**64 328 940**
NPV	**176 116 348**									
IRR	**0,1343**									

Cash flows in case 3, spot to Yokohama (Suez Canal only) - High price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez only)										
Sales volume			22 151 136	113 673 263		113 673 263	113 673 263		113 673 263	113 673 263
Sales price			16,46	16,88		20,00	20,00		20,00	20,00
Revenues			**364 643 995**	**373 906 003**		**443 022 628**	**443 022 628**		**443 022 628**	**443 022 628**
OPEX Snøhvit	5,8 USD/mmBtu		137 998 456	137 998 456		137 998 456	137 998 456		137 998 456	137 998 456
Margin after OPEX			226 645 540	235 907 548		305 024 173	305 024 173		305 024 173	305 024 173
Special taxes	0,51		115 589 225	120 312 849		155 562 328	155 562 328		155 562 328	155 562 328
Margin after special taxes			**111 056 314**	**115 594 698**		**149 461 845**	**149 461 845**		**149 461 845**	**149 461 845**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			70 362 303	75 841 868		121 548 579	123 767 834		123 767 834	123 767 834
Taxes			18 997 822	20 477 304		32 818 116	33 417 315		33 417 315	33 417 315
Profit after taxes			**51 364 481**	**55 364 564**		**88 730 462**	**90 350 518**		**90 350 518**	**90 350 518**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**47 765 172**	**50 824 074**		**72 350 408**	**96 163 018**		**96 163 018**	**108 938 018**
NPV	**540 046 544**									
IRR	**0,2225**									

Cash flows in case 3, spot to Yokohama (Suez/NSR) - Low price scenario:

Year	**2014**	**2015**	**2016**	**2017**	**…**	**2025**	**2026**	**…**	**2054**	**2055**
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez/NSR)										
Sales volume			25 912 224	25 912 224		25 912 224	25 912 224		25 912 224	25 912 224
Sales price			14,19	13,58		9,00	9,00		9,00	9,00
Revenues			**367 668 659**	**351 782 394**		**233 210 005**	**233 210 005**		**233 210 005**	**233 210 005**
OPEX Snøhvit	5,8 USD/mmBtu		161 103 220	161 103 220		161 103 220	161 103 220		161 103 220	161 103 220
Margin after OPEX			206 565 439	190 679 174		72 106 786	72 106 786		72 106 786	72 106 786
Special taxes	0,51		105 348 374	97 246 379		36 774 461	36 774 461		36 774 461	36 774 461
Margin after special taxes			**101 217 065**	**93 432 795**		**35 332 325**	**35 332 325**		**35 332 325**	**35 332 325**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			60 523 054	53 679 965		7 419 059	9 638 314		9 638 314	9 638 314
Taxes			16 341 225	14 493 591		2 003 146	2 602 345		2 602 345	2 602 345
Profit after taxes			**44 181 830**	**39 186 375**		**5 415 913**	**7 035 969**		**7 035 969**	**7 035 969**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**40 582 521**	**34 645 885**		**-10 964 141**	**12 848 469**		**12 848 469**	**25 623 469**
NPV	**-65 111 640**									
IRR	**0,0473**									

Cash flows in case 3, spot to Yokohama (Suez/NSR) - Medium price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez/NSR)										
Sales volume			25 912 224	25 912 224		25 912 224	25 912 224		25 912 224	25 912 224
Sales price			14,37	14,37		14,37	14,37		14,37	14,37
Revenues			**372 358 642**	**372 358 642**		**372 358 642**	**372 358 642**		**372 358 642**	**372 358 642**
OPEX Snøhvit	5,8 USD/mmBtu		161 103 220	161 103 220		161 103 220	161 103 220		161 103 220	161 103 220
Margin after OPEX			211 255 422	211 255 422		211 255 422	211 255 422		211 255 422	211 255 422
Special taxes	0,51		107 740 265	107 740 265		107 740 265	107 740 265		107 740 265	107 740 265
Margin after special taxes			**103 515 157**	**103 515 157**		**103 515 157**	**103 515 157**		**103 515 157**	**103 515 157**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			62 821 146	63 762 327		75 601 891	77 821 146		77 821 146	77 821 146
Taxes			16 961 709	17 215 828		20 412 511	21 011 709		21 011 709	21 011 709
Profit after taxes			**45 859 436**	**46 546 499**		**55 189 380**	**56 809 436**		**56 809 436**	**56 809 436**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**42 260 127**	**42 006 009**		**38 809 326**	**62 621 936**		**62 621 936**	**75 396 936**
NPV	**288 219 122**									
IRR	**0,1683**									

Cash flows in case 3, spot to Yokohama (Suez/NSR) - High price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez/NSR)										
Sales volume			25 912 224	25 912 224		25 912 224	25 912 224		25 912 224	25 912 224
Sales price			16,46	16,88		20,00	20,00		20,00	20,00
Revenues			**426 557 736**	**437 392 361**		**518 244 456**	**518 244 456**		**518 244 456**	**518 244 456**
OPEX Snøhvit	5,8 USD/mmBtu		161 103 220	161 103 220		161 103 220	161 103 220		161 103 220	161 103 220
Margin after OPEX			265 454 516	276 289 142		357 141 237	357 141 237		357 141 237	357 141 237
Special taxes	0,51		135 381 803	140 907 462		182 142 031	182 142 031		182 142 031	182 142 031
Margin after special taxes			**130 072 713**	**135 381 679**		**174 999 206**	**174 999 206**		**174 999 206**	**174 999 206**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			12 329 380	12 329 380		12 329 380	12 329 380		12 329 380	12 329 380
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			2 077 131	2 077 131		2 077 131	2 077 131		2 077 131	2 077 131
Sum shipping costs			**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**		**19 881 511**	**19 881 511**
Profit			89 378 702	95 628 849		147 085 940	149 305 195		149 305 195	149 305 195
Taxes			24 132 249	25 819 789		39 713 204	40 312 403		40 312 403	40 312 403
Profit after taxes			**65 246 452**	**69 809 060**		**107 372 736**	**108 992 792**		**108 992 792**	**108 992 792**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**61 647 143**	**65 268 570**		**519 504 678**	**114 805 292**		**114 805 292**	**127 580 292**
NPV	**713 941 860**									
IRR	**0,2661**									

APPENDIX 5

Case 4:

Cash flows in case 4, spot to Milford Haven combined with NSR - Low price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven/NSR										
Sales volume			84 537 912	84 537 912		84 537 912	84 537 912		84 537 912	84 537 912
Sales price			11,88	11,46		8,42	8,42		8,42	8,42
Revenues			**1 004 310 400**	**968 522 684**		**711 527 430**	**711 527 430**		**711 527 430**	**711 527 430**
OPEX Snøhvit	5,8 USD/mmBtu		498 419 575	498 419 575		498 419 575	498 419 575		498 419 575	498 419 575
Margin after OPEX			505 890 825	470 103 108		213 107 855	213 107 855		213 107 855	213 107 855
Special taxes	0,51		258 004 321	239 752 585		108 685 006	108 685 006		108 685 006	108 685 006
Margin after special taxes			**247 886 504**	**230 350 523**		**104 422 849**	**104 422 849**		**104 422 849**	**104 422 849**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			8 994 503	8 994 503		8 994 503	8 994 503		8 994 503	8 994 503
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			8 750 136	8 750 136		8 750 136	8 750 136		8 750 136	8 750 136
Sum shipping costs			**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**
Profit			203 854 365	187 259 565		78 924 729	75 390 710		75 390 710	75 390 710
Taxes			55 040 679	50 560 083		21 309 677	20 355 492		20 355 492	20 355 492
Profit after taxes			**148 813 686**	**136 699 482**		**57 615 052**	**55 035 218**		**55 035 218**	**55 035 218**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**145 214 377**	**132 158 992**		**41 234 998**	**60 847 718**		**60 847 718**	**73 622 718**
NPV	**601 057 015**									
IRR	**0,3869**									

The sales price in the all spreadsheets is the mean price for the whole year. Therefore, the sum of multiplying volume and price for each year is not accurate. (We refer to Chaper 8.7.)

Cash flows in case 4, spot to Milford Haven combined with NSR - Medium price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Yokohama (Suez/NSR)										
Sales volume			25 912 224	25 912 224		25 912 224	25 912 224		25 912 224	25 912 224
Sales price			14,37	14,37		14,37	14,37		14,37	14,37
Revenues			**929 917 037**	**929 917 037**		**929 917 037**	**929 917 037**		**929 917 037**	**929 917 037**
OPEX Snøhvit	5,8 USD/mmBtu		498 419 575	498 419 575		498 419 575	498 419 575		498 419 575	498 419 575
Margin after OPEX			431 497 462	431 497 462		431 497 462	431 497 462		431 497 462	431 497 462
Special taxes	0,51		220 063 705	220 063 705		220 063 705	220 063 705		220 063 705	220 063 705
Margin after special taxes			**211 433 756**	**211 433 756**		**211 433 756**	**211 433 756**		**211 433 756**	**211 433 756**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			8 994 503	8 994 503		8 994 503	8 994 503		8 994 503	8 994 503
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			8 750 136	8 750 136		8 750 136	8 750 136		8 750 136	8 750 136
Sum shipping costs			**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**
Profit			167 401 617	168 342 798		180 182 362	182 401 617		182 401 617	182 401 617
Taxes			45 198 437	45 452 556		48 649 238	49 248 437		49 248 437	49 248 437
Profit after taxes			**122 203 181**	**122 890 243**		**131 533 124**	**133 153 181**		**133 153 181**	**133 153 181**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**118 603 872**	**118 349 753**		**115 153 070**	**138 965 681**		**138 965 681**	**151 740 681**
NPV	**1 061 470 698**									
IRR	**0,3963**									

Cash flows in case 4, spot to Milford Haven combined with NSR - High price scenario:

Year	2014	2015	2016	2017	…	2025	2026	…	2054	2055
All numbers in USD			Delivery of vessel							
Spot										
Vessel lifetime			1	2		10	11		39	40
Melkøya ↔ Milford Haven/NSR										
Sales volume			84 537 912	84 537 912		84 537 912	84 537 912		84 537 912	84 537 912
Sales price			13,82	14,27		17,67	17,67		17,67	17,67
Revenues			**1 168 313 950**	**1 206 637 804**		**1 493 503 120**	**1 493 503 120**		**1 493 503 120**	**1 493 503 120**
OPEX Snøhvit	5,8 USD/mmBtu		498 419 575	498 419 575		498 419 575	498 419 575		498 419 575	498 419 575
Margin after OPEX			669 894 375	708 218 228		995 083 545	995 083 545		995 083 545	995 083 545
Special taxes	0,51		341 646 131	361 191 297		507 492 608	507 492 608		507 492 608	507 492 608
Margin after special taxes			**328 248 244**	**347 026 932**		**487 590 937**	**487 590 937**		**487 590 937**	**487 590 937**
Capex	125 000 000	125 000 000								
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Interest payments			15 000 000	14 058 819		2 219 255				
Salvage value (year 40)	17 500 000									
Fuel costs			8 994 503	8 994 503		8 994 503	8 994 503		8 994 503	8 994 503
Operational costs			5 475 000	5 475 000		5 475 000	5 475 000		5 475 000	5 475 000
Voyage costs			8 750 136	8 750 136		8 750 136	8 750 136		8 750 136	8 750 136
Sum shipping costs			**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**		**23 219 639**	**23 219 639**
Profit			284 216 105	303 935 974		456 339 543	458 558 798		458 558 798	458 558 798
Taxes			76 738 348	82 062 713		123 810 875	123 810 875		123 810 875	123 810 875
Profit after taxes			**207 477 756**	**221 873 261**		**333 127 866**	**334 747 923**		**334 747 923**	**334 747 923**
Loan payments			9 411 809	10 352 990		22 192 554				
Depreciation			5 812 500	5 812 500		5 812 500	5 812 500		5 812 500	5 812 500
Cash flows	**-125 000 000**	**-125 000 000**	**203 878 447**	**217 332 771**		**316 747 812**	**340 560 423**		**340 560 423**	**353 335 423**
NPV	**2 739 444 700**									
IRR	**0,6705**									