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Stavanger, 14.06.2018
Øystein Fitjar Waage

Abstracts

The discovery of oil on the Norwegian continental shelf in 1969 ushered an industry that would become the most important industry in Norway. The government created fiscal regimes that would secure the national interests in production of this resource.

Over the course of the last 35 years there have been several crises in the Norwegian industry. 1986, 1998, 2008 and 2014 are the years when four of the most pronounced oil crises in was initiated. The objective of this thesis is to analyze and compare the historical and most recent oil crises in the Norwegian petroleum industry. The aim is to reveal causes and similarities, how the crises manifested in the Norwegian industry and what was done to mitigate the crises.

The bust in oil prices in 1986 was caused by OPEC's price manipulation. This was the first substantial drop in oil prices ever experienced on the Norwegian continental shelf. This prompted the Norwegian government to revise the fiscal regime and make the shelf more accessible for foreign companies.

In 1998, the global consumption of oil fell, causing an over-supply of oil in a period when the activity on the continental shelf was high. To mitigate the crisis that emerged from the combination of high costs and low a low oil price, the industry moved towards a higher degree of cooperation through mergers, a commitment to new industry standards and new contract formats that where based more on the long-term cooperation. The large oil price drop in 2008 did not have a pernicious effect on the Norwegian petroleum industry as this crisis affected most parts of the global economy, and the oil price increased fairly rapidly. From June 2014, the oil price fell from 110 to 34 dollars per barrel over the course of 1 year and 6 months. This fall in prices was driven by the surge in production of non-conventional shale oil in the America, followed by an increased supply from OPEC. The industry had for the years leading up to the crises experienced large increases in drilling costs, and cost overruns when developing new fields.

The Norwegian petroleum industry has been subject to multiple changes in fiscal framework and organizational structures. Also, the industry has been driven by substantial technological developments. Substantial changes in the industry has, for the most part been driven by periods of low profitability for companies producing oil on the Norwegian Continental Shelf. Some fundamental developments in the industry creates important differentiations between historical crises in the Norwegian Continental Shelf. The overarching theme is that the potential for development on the continental shelf is diminishing. This has contributed to increase the effects of the recent crisis in 2014.

The main findings in this thesis is that crises in the Norwegian petroleum industry have been preceded by a period of high activity and large cost overrun that amplify the crises. The largest manifestation of the crises has been the reduction in invested capital. The moves that have been made to mitigate the crises have largely been consolidation, increased cooperation between companies and commitment to industry standards.

Table of Contents

List of Figures

List of Tables

List of Abbreviations

Table 1-1

ICE	Intercontinental Exchange
WTI	West Texas Intermediate
OPEC	Organization of Petroleum Exporting Countries
BP	British Petroleum
CPI	Consumer Price Index
Mtoe	Million-ton oil equivalents
Mb/d	Million barrels per day
LNG	Liquid Natural Gas
NPD	Norwegian Petroleum Directorate
PUD	Plan for Utbygging og Drift
PAD	Plan for Anlegg og Drift
NOU	Norges Offentlige Utredning
GDP	Gross National Production
EEA	European Economic Area
SDØE	Statens Direkte Økonomiske Engasjement
NCS	Norwegian Continental Shelf
Sm3	Standard Cubic meter
E&P	Exploration and Production
EPC	Engineering Procurement and Construction

1. Introduction

1.1 Background and Motivation

From June 2014, the oil price fell from 110 to 34 dollars per barrel over the course of 1.5 years. The petroleum industry is large in Norway, and the plummeting oil price greatly influenced large parts of the Norwegian economy. To the man in the street, the effects were perhaps most visible through a sudden and general pessimism in the job market. Unemployment increased, and newly graduates in technical fields experienced a hard time getting jobs. As a 2016 graduate in mechanical engineering, the author of this thesis felt the effects of the downturn first hand and was thereby inspired to pursue a master's degree in industrial economics to "ride out the storm".

Through industrial economics courses, the author became aware that there have been multiple "ups and downs" in the petroleum industry. This sparked an interest to investigate similarities in cause and effects of oil price busts. At the current time, in 2018, some segments of the oil industry have started to recover, and most of the numbers from the period are now available. This makes it possible to compare the recent downturn with historical downturns in the oil industry.

What caused the booms and busts in the oil price, and what was done by the affected parties to mitigate and recover?

This is a very broad area of research. This thesis will therefore limit its focus to the Norwegian industry, but the thesis also draws on some global factors and examples.

1.2 Objectives

The objective of this thesis is to analyze and compare historical and the recent economic crises in the Norwegian petroleum industry. The aim is to reveal similarities, how the crises manifested in the industry and what was done to mitigate the crises. The comparisons are viewed in light of fundamental long-term trends, both quantitative and qualitative, that has shaped the Norwegian petroleum industry.

1.3 The Structure and Focus of the Report

This thesis will investigate the similarities in former and the recent economic crises in the Norwegian petroleum industry by investigating;

- The global petroleum market, and the fragile equilibrium that causes sudden shifts in prices (Chapter 1)
- Historical accounts of happenings on The Shelf (Chapter 2)
- The different fiscal frameworks that have been at play, and how they may have affected the industry (Chapter 2)
- Some of the remedies that was utilized to overcome the downturn in the industry (Chapter 2)
- Aggregated data that account for the development in available resources, development in fields, employment activity in the supply sector, government distribution of license and granted approval for field development and number of companies operating on the shelf (Chapter 3)

1.4 A Short Introduction to the International Petroleum Market

Oil, gas and coal are the most important sources of energy in the world today. Approximately 85% of our energy came from these sources in 2015. The share of each energy source is shown in Figure 1-1.

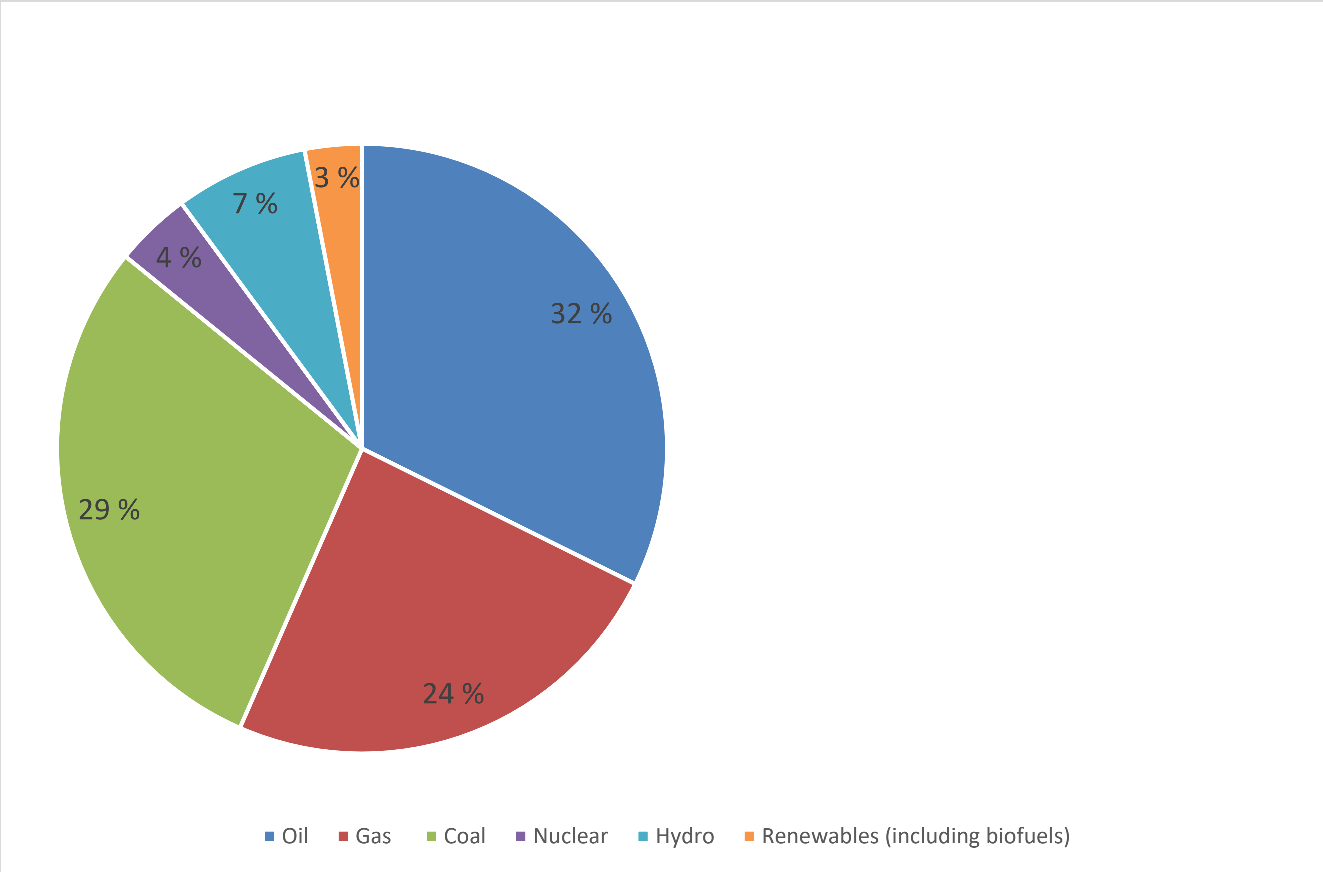

Figure 1-1 Energy sources consumed by the world in 2015 (BP, 2017)

Although there is a strong movement toward renewable energy sources, British Petroleum predicts that in 2035 a shear of 78% of our energy will still come from fossil fuel sources. Due to population growth and increase in per capita energy consumption, the actual consumption of fossil energy sources will increase by approximately 8%, where natural gas will have the highest relative growth of the petroleum sources. A display of the primary energy consumption in Mtoe[1] in 2015 and a prediction of energy consumption in 2035 can be seen below in Table 1-1 (**BP**, 2017).

[1] Million Tons of Oil Equivalents.

Table 1-1 Energy outlook (BP, 2017)

	Level		Shares		Change (abs.)		Change (%)	
					1995-	2015-	1995-	2015 -
	2015	2035	2015	2035	2015	2035	2015	2035
Oil	93	106	32 %	29 %	23	14	32 %	15 %
Gas	336	462	24 %	25 %	129	127	63 %	38 %
Coal	3840	4032	29 %	24 %	1595	193	71 %	5 %
Nuclear	583	927	4 %	5 %	57	344	11 %	59 %
Hydro	893	1272	7 %	7 %	330	379	59 %	42 %
Renewables (including biofuels)	439	1715	3 %	10 %	394	1276	870 %	291 %

1.4.1 Natural gas

Natural gas is the third largest source of energy in the world, accounting for 24 percent of total energy consumption in 2015. The demand for natural gas has increased in recent years, and it is gaining importance as a less polluting alternative to coal. As can be seen from Table 1-1, natural gas consumption is predicted to increase further and account for approximately 25% in 2035; in absolute numbers this corresponds to a rise from 336 Mtoe to 465Mtoe. Distribution of natural gas often require large upfront investments. For pipelines, there are limits to the possible length of pipe, and for LNG (Liquid Natural Gas) there is a need for a liquification plant, shipping and a gasification plant. Because of these factors, gas is to a large degree sold on long term contracts, and gas reservoirs are usually only profitable if they are large and located close to existing infrastructure and an existing market. (Deutschebank, 2013)

To a greater extent than oil, gas price follows a seasonal cycle. This is partly because the demand rises in the winter when heating is needed, and a small peak in the summer caused by higher demand for electricity that is used by air conditioning. Figure 1-2 displays a time series of the price of natural gas on the American market.

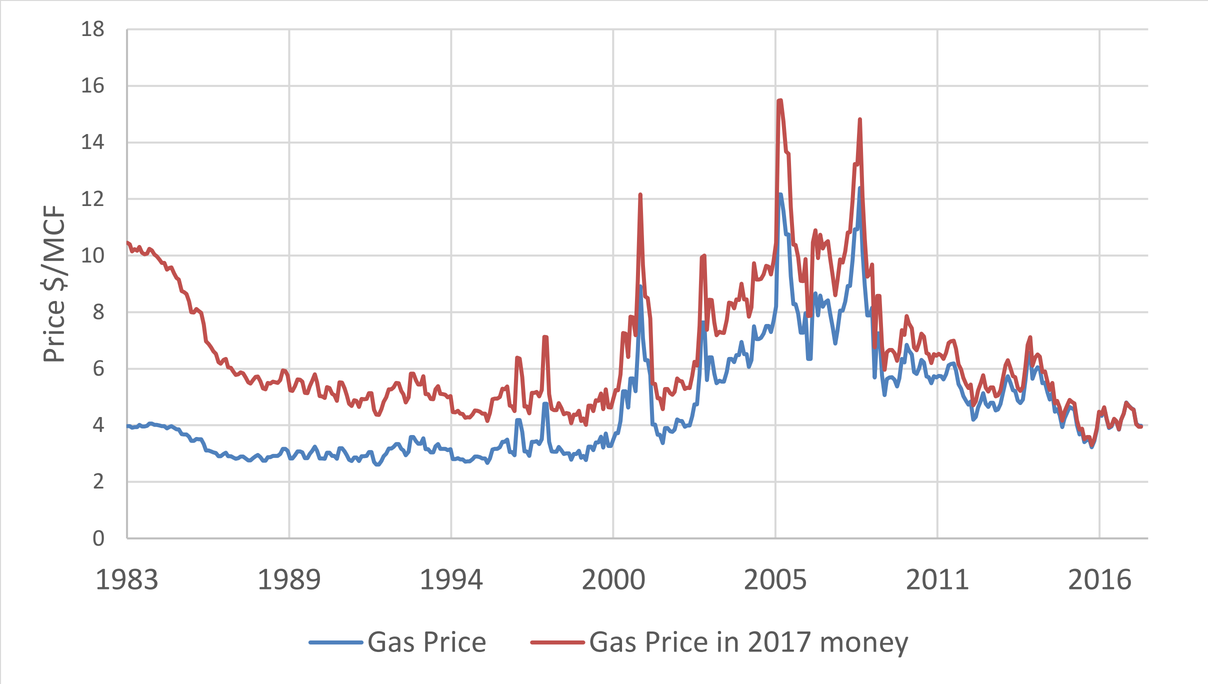

Figure 1-2 Gas prices on the American marked (EIA, 2018)

Unlike other crude, gas can be substituted by coal or fuel oil in large powerplants, depending on which is most economical at any given time.

1.4.2 Oil

Crude oil is a generic term for oil prior to refining. There are over 100 different types of crude oil, which has inherent characteristics that are attractive for different reasons and purposes. Some of the main areas where crude oil differs in quality is in density, sulfur content and the flow properties.

Density is an aspect that decides what products that can be refined from the oil. Low density oils tend to yield more of the higher value products such as gasoline. A *high sulfur content* is an undesirable property when it appears in large quantities, therefore, crudes with high Sulphur contents require more processing and a greater energy input in the refining process. When the Sulphur content is <0.5%, the crude is classified as "sweet", and the crude is called "sour" when the Sulphur content in the oil is higher than 0.5%. The *flow properties* of the oil, often measured in relation to the *pour point*, is a measure of the lowest temperatures where the crude oil will flow. At higher pour point the oil might have to be heated for it to flow as a liquid. This will have an impact on how the oil is stored and transported.

The value of crude oil depends on the inherent combination of characteristics the crude has, and what characteristics that is in demand for refineries and oil storage's. Because there are certain combinations of characteristics that are preferred over others, crude oil is sometimes blended to create these desired qualities.

There are no overarching markers for oil prices, but there are some blends of crude oil that are used as markers from which the price of other qualities will be derived. Some of the key global markers are the West Texas Intermediate (WTI), which originates from the USA, and the Brent[2] oil, which originates from the Brent field on the British sector in the North Sea.

The selection of benchmark crude does not follow any predetermined formula. Brent is a key global marker even though it only accounts for a small portion of the total world production. Some of the reason for why this crude became a global benchmark is the political stability in the part of the world where it is produced (Schofield, 2007). Brent crude assessments, based on physical trades or the ICE[3] Brent futures market, were used to directly or indirectly price 70% of world oil in 2013 (Fielden, 2013).

As Figure 3-1 displays, the oil price is volatile. The cause for volatile changes can be sorted in three main categories according Lutz Kilian (Kilian, 2009); shocks to the current oil supply, fluctuation in the current global demand (aggregate demand shock) for oil and shifts in the precautionary demand[4] for oil. By Kilian`s estimations, each of the three main categories have a different effect on real oil price[5] (Kilian, 2009).

David S. Jacks (Jacks, 2013) argues that the topology of real commodity prices in a time series is comprised of a long-run trend, medium-run cycles and short-run boom and bust episodes. Jacks paper from 2013 finds that the real price of commodities in general has been on the rise since 1950. Especially commodities "from the ground", such as oil or metals.

A paper by James D. Hamilton (Hamilton, 2008) states that the best prediction for future oil prices might well be the current oil prices. His paper locked into the predictability of oil prices based on three separate conditions that should all hold in equilibrium; storage, futures market and the scarcity rent. If there is an increasing trend in oil prices it would be easy to make money; just buy oil, store it and sell later. But, it's not that simple, an increasing in stored oil would signals to the marked that oil prices will rise in the future, and the marked will thereby mitigate the future price increase.

According to Hamilton, Harold Hotelling pointed out in 1931 that in case of an exhaustible resource, prices should exceed the marginal cost even if the oil market were perfectly competitive. Hotelling's principle means that the scarcity rent should rise at the rate close to the rate of interest. Although this theory is elegant, it does not seem to apply to the oil price. Economists often think of oil as historically having not been influenced by the issue of exhaustibility. Also, there has been a downward spiralling trend of the marginal cost due to technological improvements. Hamilton's paper concludes that the high prices in the summer of 2008 was driven by speculations, strong world demand, time delays of geological limitations,

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[2] This crude originated from the Brent oil field in the UK sector of the North Sea. The production began in 1976 and the peak production was almost half a million barrels a day in 1982. In 2006 planning for decommissioning started (Shell, 2018).
[3] Intercontinental Exchange (ICE)
[4] Precautionary demand is driven by uncertainty regarding the future supply and the demand of oil.
[5] Real oil price appears when adjusting the oil price with an index for real economic activity

OPEC monopoly pricing and an increasing contribution from the scarcity rent. The paper also predicts that scarcity rent will play a bigger role in the future (Hamilton, 2008).

As will be described in chapter 1.4.3 the surge in production of unconventional oil resources that started in 2008, might have postponed the scarcity rent once again.

Hoteling's paper notes that because of the long lead time between the initial reservoir discovery and when the refined petroleum product is delivered to the consumer, and the absence of significant excess production capacity, the short run price elasticity of oil supply is low.

John CB Cooper (Cooper, 2003) points out that the long run demand elasticity of crude oil is between -0.2 and -0.3, and in the short run the elasticity is below -0.1.

1.4.3 Shale Oil

To produce shale oil, it is usually necessary to use fracking and drill horizontal wells. This method of producing oil is more expensive than conventional production methods. According to EIA the U.S has 48 Billion barrels of technically recoverable shale oil, Russia has a large shale oil reservoirs of 75 Billion barrels (EIA, 2013) and recently a large reservoir of 80 billion barrels of shale oil where discovered in Bahrain (NTB, 2018).

In 2008, the U.S production of shale oil surged and caused an upswing in the U.S oil sector that few analytics had anticipated. The oil price was not substantially affected by this until 2014. Two main reasons for this was the bottlenecked distribution system in the U.S, and the export ban that prevented producers to export their oil, the export ban was lifted in 2015. The International Energy Agency (IEA) reports that the US is on pace to become the largest oil producer by 2023, and that the pipeline capacity and export ports are the largest bottlenecks to development in the US production. The article points out that the capacity problems caused local prices to be 20 dollars below the WTI benchmark (Lejeune, 2018).

In a working paper written by Rebelo, Krusell and Bornstein they state that it is less costly for fracking firms to adjust their level of production in the short run and it is a shorter lag between investment and production start compared to traditional oil production. This makes the fracking firms more responsive to changes in oil price. They state that the presence of fracking companies reduces the volatility in the oil market because they are nimbler in adjusting their production in existing fields and in starting production in new fields (Bornstein, Krusell, & Rebelo, 2017).

Although shale oil production has increased the supply of oil and has had a large influence on the global oil market, there are some doubts regarding the profitability of fracking. Amrita Sen explained in an interview with *Dagens Næringsliv* that she does not believe that fracking companies are able to earn money and that she will not believe they can before she is able to observe positive revenue streams (Sen, 2018).

1.4.4 OPEC

The Organization of Petroleum Exporting Countries[6] (OPEC) is the largest influence on the supply side of the global oil market. They account for around 42% of world oil production and the members of OPEC control 80% of the worlds proven petroleum reserves (Deutschebank, 2013).

At its simplest, OPEC works as a supply side swing to coordinate production amongst its members to keep the market in balance around a certain price range. OPEC has had a great influence on the price of oil. In 1973, allegedly as a response to the US support to Israel in the Yom Kippur war, the Arab nations issued an embargo on oil export to the US. This resulted in a sudden price increase and the world economy entered a recession. The behavior of OPEC does resemble a text book example of a cartel behavior, which is to increase prices and as the marked adapts prices goes down below previous prices due to higher supply capacity.

Members of OPEC are given a production quota based on their proven oil reserves. This quota is not always followed by the members, and it is likely that the daily production is to a large degree reflecting capacity rather than their quota level. OPEC members and their allies are the only oil producing countries where spear production capacity resides, while countries outside OPEC seek to produce at full capacity (Deutschebank, 2013).

After the 2014 drop in oil prices, OPEC members agreed on a reduction of 1.2mb/d and thus a new production ceiling of 32.5 Mb/d effective of 1st of January 2017, Russia agreed to cut production by 600kb/d (OPEC, 2016). OPEC and Russia has agreed to extend this agreement to the end of 2018, and they retain the option to abandon the deal if the market flips into a deficit to soon (Lawler, Gamal, & Nasralla, 2017).

The decline in the Venezuelan oil production can contribute to consume OPEC's outstanding production capacity, which again can make the oil market more volatile (Johan Nordstrøm & Hans Henrik Torgersen, 2018).

1.4.5 Geopolitical Events and Trends Influence the Petroleum Market

Geopolitical events can affect the oil price and create shifts in the market. Some historical examples of such events will be discussed in this subchapter to illustrate this. To support the discussions in this chapter, the reader is advised to revisit Figure 3-1 in chapter 3.1.

Some of the fluctuation in the oil price can be attributed to structural changes in the oil market. For instance, the oil embargo imposed on the US by OPEC in 1973 caused a large upswing in oil price. After the boom in 1979, speculation and trading in future contracts became more popular. This was believed to stabilize the oil price, as the market was more equipped to account for future events.

[6] Algeria, Angola, Ecuador, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela

The surge in the paper market did, to some degree, move the oil price away from the actual cost of producing and distribute oil. In 1985, when Saudi-Arabia started to price their oil according to the market price as opposed to earlier when the price of Saudi oil was politically decided, the price of oil had a sharp drop.

From 1980 to 2000 the oil consumption increased 1-1.5% each year. At the same time the price of oil was declining, except for a short period in 1991 when the Gulf war was initiated, the price quickly fell back to its long-term trend. This gave week incentives to invest in oil production, thus contributing to the foundation for the high prices that is observed in the future.

After USA invaded Iraq, the oil price had a boom. Other reasons for the boom in oil price from 2003 to 2008 was an increasing demand from China[7], and a weakening of the dollar against the euro, thus making a position in oil a rational way to mitigate the fall in the value of dollar[8]. Speculations in the oil marked may also be among the reasons for what looks like a bubble in the oil price from 2007-2008 (Noreng, 2009).

The relatively high prices from 2010-2014 can be attributed to a lack in production capacity due to underinvestment in production, and political instability. The Arab spring started in 2010, and Libya's production was halted due to war.

During the first quarter of 2018, the oil price has risen from 63 dollars per barrel to 80 dollars per barrel in May. There are some current uncertainties in the political landscape which makes future oil price hard to predict. In an interview with E24, oil expert Torbjørn Kjus addresses resent shifts in the oil marked. Because Venezuela and Iran[9] are both entangled in unfavourable political situations, there is increased uncertainty to future production. Venezuela has the largest oil reserves in the world, but their production is at its lowest in 33 years. Since February 2016 their production has dropped by 35%, the production is now at 1,6 million barrels per day and its predicted to be 1 million within 5 months (Johan Nordstrøm & Hans Henrik Torgersen, 2018)

This uncertainty has led to an increase in the future market pricing of oil; the price jumped from an expected 60 to 67 dollars per barrel in 2021. This allows producers to secure higher prices on future production. OPEC members are, according to Bloomberg[10] discussing whether to resume full production (Nilsen, 20118).

[7] China became part of the world economy when they became members of WTO (World Trade Organization) in 2003.

[8] From 2002-2008 the oil price increased 4-fold in dollar and 2,5-fold in euro.

[9] Iran was in some political disputes with USA, this creates uncertainty in future oil supply as Iran is a large producer.

[10] (Blas, Khrennikova, & Mazneva, 2018)

2. The Norwegian Petroleum Industry: Historical Trends and Developments, and the Fiscal Framework

2.1 History

In 1962, the first approach was made to the Norwegian authorities by Phillips Petroleum Co, when they requested a permission to start seismic surveying in the North Sea. Prior to this, there had been little interest in this area, as few believed that there could be oil and gas present on the Norwegian Continental Shelf (NCS), the Shelf is displayed in Figure 2-1.

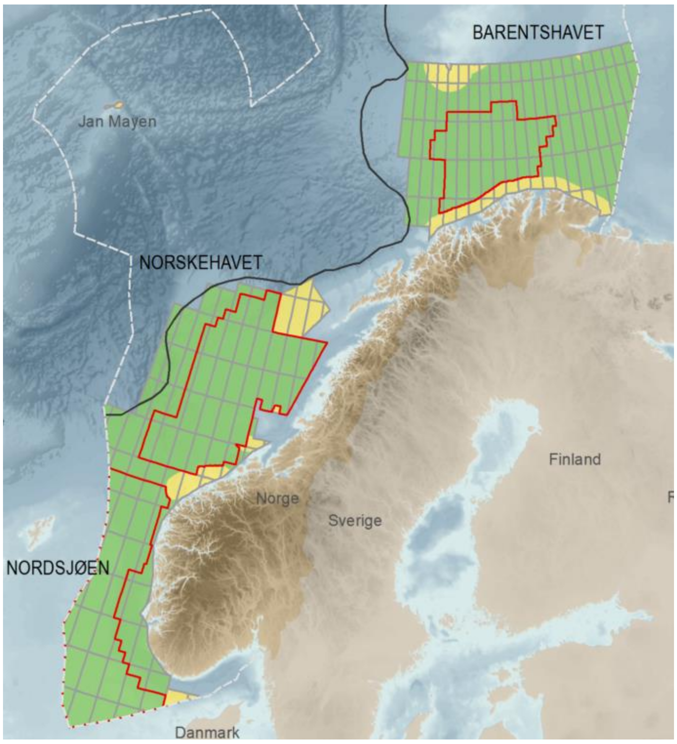

Figure 2-1 The Norwegian Continental Shelf (Norwegian Petroleum, 2018c).

However, the following searches proved successful, and the Ekofisk field was discovered in 1969. In 1971 this field was declared commercial, as the first of many fields on the Norwegian Continental Shelf.

In 1971, the parliaments industry comity wrote a document that would become “The Ten Oil Commandments”. The content of this document has had an influential effect on Norwegian oil policy. Both the commandments and the laws that followed might give the best indication for what the Norwegian state wants to achieve through the petroleum industry. The ten commandments are listed below:

1. National governance and control must be ensured for all activities on the Norwegian Continental Shelf.
2. Petroleum resources are exploited so that Norway becomes as independent as possible from other petroleum producers when it comes to supply of crude oil to the nation.
3. The petroleum shall be a basis for new industries.
4. Development of the industry must be done in a way that considers existing industries and the environment.
5. Flaring of exploitable gas on the Norwegian continental shelf must not be accepted, except for short testing periods.
6. Petroleum from the Norwegian Continental Shelf must be landed in Norway, unless if sociopolitical considerations dictate a better solution.
7. The state shall be engaged on all appropriate levels to contribute to coordination of Norwegian interests within Norwegian petroleum industry and the development of a Norwegian oil milieu with national and international goals.
8. A governmental oil company shall be established, and this company shall look after state interests in the commercial aspects of the oil industry and engage in cooperation’s that serve the commercial goal with both national and foreign oil interests.
9. North of the 62 latitude activities shall be chosen to satisfy special sociopolitical issues that ties to the region
10. Norwegian oil discoveries will increasingly introduce Norwegian foreign policy to new tasks.
    (Lerøen, 2010)

In 1972, Stortinget established the governmental oil company Statoil (Now Equinor), and the Oil Directorate. In 1974, Statfjord was discovered. Later this decade, Troll, Gullfaks and Frigg was proven, and experts forecasted that Norwegian gas will be delivered for several generations to come. (Kindingstad, Hagir, Wigestrand, Berge, & Hagemann, 2002)

As can be seen from the ten commandments, when the oil industry was being established on the NCS, there was an urge to secure strong national control over oil resources and assure Norwegian accumulation of experience in various sectors of the oil industry. One could say that the Norwegian oil policies at the time was to some degree protectionist. When Statoil was established, it was given a 50% share of each block on the continental shelf. The “gliding scale” approach was introduced in 1974 and meant that the State had an option to increase its share of discoveries after they had been declared profitable. As a way of protecting national interests, Statoil did not have to pay for exploration costs. In 1979, the cost carrying principle was changed so that only foreign companies would have to carry the exploration costs.

In 1984, SDØE (Statens Direkte Økonomiske Engasjement) was established. This institution would become Petoro in 2001. SDØE's objective was to secure the highest possible income to the State by owning shares in fields, pipelines, licenses (Olje- og Energidepartementet, 2000).

Prior to the oil price bust in 1986, the oil price had been high and on a declining trend since 1973, and 18 fields had been approved for production. The average size of these fields was large measured in oil equivalents. These figures are represented later, in Figure 3-22 and Figure 3-24 in chapter 3.2.1. The 1986 bust, combined with pessimism in regard to finding new large fields, initiated the end of the protectionism that had previous been a part of the Norwegian regulations on the NCS, according to Helge Ryggvik (Ryggvik, 2015). Also, EØS was on the table from 1989, this have influenced the law makers to further liberalize the fiscal framework. The policy of cost carrying was ended in 1992 and "gliding scale" approach was ended in 1993. (Olje- og Energidepartementet, 2000).

2.1.1 Summary of Important Events Reported in Press Releases from the Norwegian Oil Directorate

From 1986 to 1988 some of the most important events was; the bust in oil price that reached the bottom in 1986, and deal called "Trollavtalen" (TGSA) regarding gas sales from Sleipner and Troll was made. The report argues that oilfield should be saved for periods with low gas activities to ensure that as much as possible of the existing gas resources is exploited. The legal framework was revised to find whether it was driving cost. In 1987 Norway contributed in straining world supply of oil. Also, changes in tax, somewhat higher prices and development in technology made it possible to develop new fields. In 1988 the first subsea installations where introduced and the government approved an unmanned oil installation. Reduction in staff seemed to be a trend (Norwegian Oil Directorate, 2018a).

From 1995 to 2001 several things happened; The NORSOK initiative was initiated in 1995, this was a cooperation between government and several oil companies and supply companies to reduce the cost on the Norwegian continental shelf. Because of the high number of ambitious projects that was initiate in the period 1995-1997, the activity in the industry was at an all-time high in 1998, this was accompanied with a low oil price.

This incentivised the oil companies to reduce costs, both in investments and operations. This resulted in:

- Reduction in planed exploration activity
- Postponing of development plans
- Outsourcing of secondary functions
- Merges of companies
- Reduction in cost of operation
- Reduction in staff

To mitigate against too much activity in this period, the government adjusted the timing for new projects. In 2001 Statoil was partly privatized, and parts of SDØE was sold to Statoil. A new legal framework was introduced along with the new organizational structures that could be utilized in project developments. (Norwegian Oil Directorate, 2018b)

From 2012 to 2014; In this press release from 2012, low capacity is pointed out as a challenge. The capacity shortage in the labour market is mitigated trough increase division of assignments and labour migration, and the international supplier marked. The report points to bottlenecks in the value chain, for instance, lack of drilling capacity was representing a bottle neck, this changed as new rigs where constructed Segments of the industry that is most affected by lack in capacity was in assessing and maturing of projects.

In the rapport for the Norwegian shelf 2014, the opinion of the Oil Directorate is that the weak oil prices could drive some necessary readjustments in the sector, they point towards high costs. A reduction in cost could lay the foundation for robust profitability over time.

In 2016, an indicator for the fall in development cost has been derived from seven projects where the oil companies have revised their cost estimates. What is similar between these projects[11] is that the development concept has not changed between 2014 and 2016.

From a long term socioeconomic perspective, it is important that as much of the accessible resources in an area is discovered and tied up to existing infrastructure before the infrastructure is removed. The government regulates this to some degree trough the way they issue exploration licenses and trough rich access to data and stable and predictable regulatory conditions. (Norwegian Oil Directorate, 2018a).

Since 2014 the industry has initiate large counter measures to cut costs in all phases of the projects. The cost of developing a project has been reduced by 30-50% the last couple of years. Cost of operations are down by 30% compared to 2013/2014. Combine this with the rise in the oil price and the oil producing companies have more profitable options.

[11] Johan Sverdrup Phase II, Johan Castberg, Utgard, Oda, Trestakk, Dvalin and Snilehorn

“Projects that are started now, generally have a high profitability and can handle a price of oil down to 30-40 dollar” (Nyland, 2018)

The rapport points to simpler and more standardized solutions as the main contributors to the decrease in cost of new projects. The reduction in cost of operations are attributed to effectivity measures, simplified processes and lower supply prices. Between 2010 and 2014, when the oil price where above 100 dollars for a large portion of the time, many discoveries where subject to development, also older discoveries. This imply that oil companies made investments based on a high oil price, thus making them vulnerable for fluctuations in price. One important aspect of the continental shelf is that many smaller reservoirs of oil/gas is only viable for production while there is existing infrastructure in proximity. The question is if the government should encourage oil companies to produce these recourses even though they are not particularly profitable for oil companies. There can be some beneficial socioeconomic aspects to developing these resources. (Oljedirektoratet, 2018)

2.1.2 NORSOK: A Remedy for the High Costs on the Continental Shelf During the 1990s

In the 1990s, the costs on the NCS were too high for the Norwegian oil sector to be able to compete internationally, according to the NOU1999:11 (Kaasen et al., 1999). Some of the reason for the high costs were attributed to the general structure of project developments in the 1980s. This way of working was characterized by a step by step progress; first the E&P (Exploration and Production) companies decided the fundamental technical specifications, then an engineering company worked out the technical specifications on a detail level suitable for construction. Finally, the construction and commissioning were done, and this step was usually micro managed by the E&P company.

A delegation with representatives from the government, oil companies and supply companies were organized in what was called the NORSOK-process. The goal of this delegation was to find ways to increase the Norwegian petroleum industry’s ability to compete on the international marked. There were 7 dimensions which garnered their attention:

- Cost analyzes and target price
- Standardizing
- Relationship between operator and supplier
- Documentation and information technology
- Distribution
- Health, Safety and Environment
- Framework conditions

Between 1995 and 1998, new ways of organizing projects were implemented.

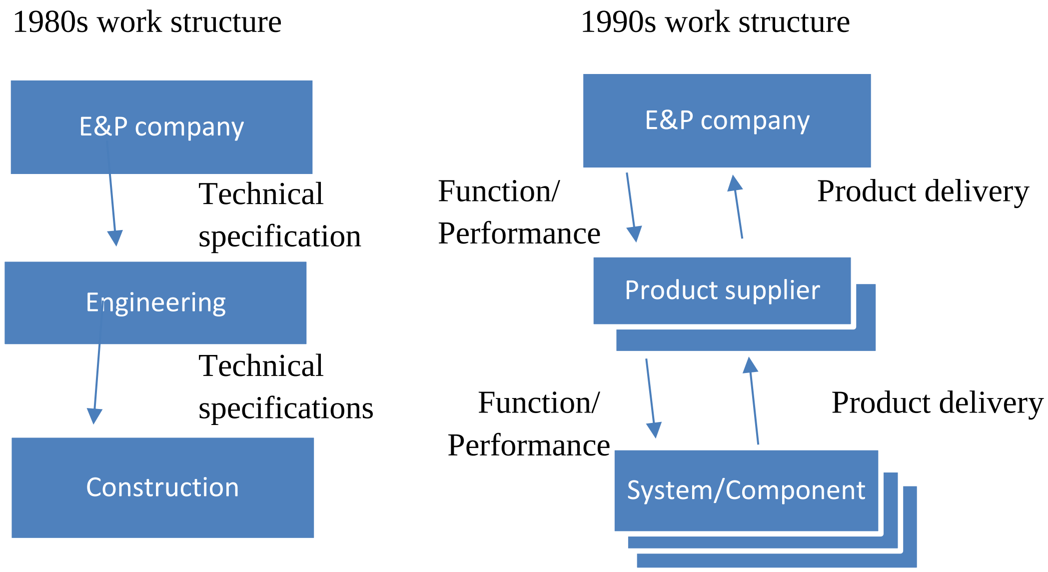

Figure 2-2 Change in work structure (Kaasen et al., 1999).

As illustrated in Figure 2-2, the development projects were initiated in a sequential manner in the 1980s and there was more of a "top down" approach when organizing the projects, the production companies would organize all parts of the projects.

The new model that was introduced through the NORSOK-process, was utilized in the late 1990s. The oil companies defined the function and performance rather than the technical specifications, and the product supplier were responsible for delivering a finished product.

This incentivized suppliers to specialize and acquire knowledge in necessary markets or aspects of a project. Further on, the suppliers had to compete to supply high quality and low price. One key difference from earlier projects was that the E&P companies were less inclined to meddle in the process. The product supplier could divide the product into smaller systems and components and procure this from a larger pool of sub suppliers. This allowed for more of a "bottom up" structure to the organization of projects, and fewer interfaces for the E&P-companies.

Another important result from implementing the NORSOK standards is the shortening of project duration. This can have a major effect on cost, not only because the cost of some inputs is proportional to time used, but also because the real net present value of a project gets larger if positive money flow can occur earlier.

In the 1980s, the normal projecting model was sequential as shown in Figure 2-3 and later in the 1990s a model that allowed for more parallel activities was adopted.

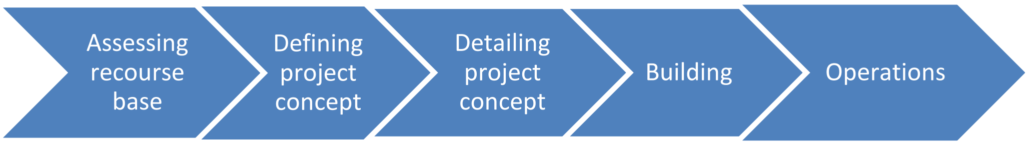

Figure 2-3 1980s Sequence of work. (Kaasen et al., 1999)

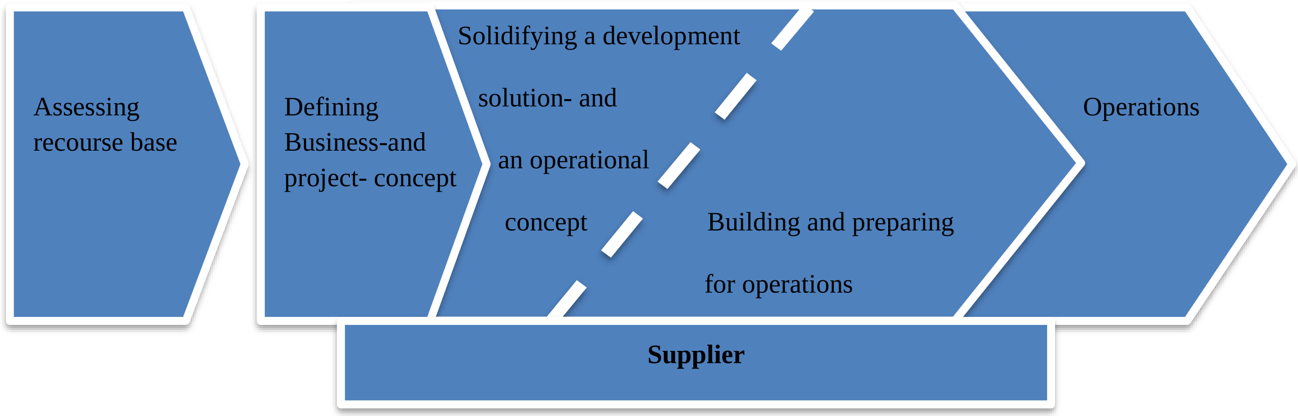

Figure 2-4 New project model. (Kaasen et al., 1999)

Figure 2-4 illustrates how some of the tasks could run parallel with other tasks. The building and preparations for operations were often initialized before the plans and concepts where fully solidified. When using this approach to the project development process, the supplier is involved on an earlier stage, often at a time when the parameters and framework for the project are still under development.

NOU1999:11 (Kaasen et al., 1999) does not make any suggestions whether this was positive regarding fewer cost overruns in projects. Suppliers might opt for more expensive solutions, and the supplier does in some cases profit from changes in the plan. In some instances, this can be regarded as an incentive to make decisions that will require change later in the process. This model opens for more opportunistic actions on the part of the platform builder, as he gained a stronger negotiation position as the construction proceeded.

The demand for shorter project duration and closer cooperation between participants has also led to a development in the contract model along two main axes. On the one axis, there is an increase in time horizon for business relations, proven by the fact that many of the large oil companies has established framework agreements for some important systems and components. Some of the intent by implementing framework agreements, was partly to increase the degree of standardization, lowering the operational cost and to facilitate the procurement phase for the supplier.

Along the other axis, there has been an increase in commitment between customer and supplier. The cooperation format used in the period analyzed in NOU:1999 ranged from traditional contract formats to joint ventures. There were some mixed experiences from this period, but the experience revealed that a closer commitment between buyer and supplier demands a large focus on feedback and further development of the contract format.

A published paper by Olsen and Osmundsen (Olsen & Osmundsen, 2005)investigates the tradeoff between fixed price contracts and a cost-plus contract; where the fixed price contract leaves all the risk to the builder and the cost-plus price contract leaves no incentives for cost control or time management. The risk is to some degree endogenous, meaning some of the risk is linked to planning and internal procedures. The risk associated with a project is correlated with the size, complexity and novelty of a project. Procurement risk can be perceived as a tradeoff between time cost and incentive cost. In large projects on the continental shelf, a one year delay in a certain project can increase the cost by as much as 25% in terms of net present value according to Olsen and Osmundsen. (Olsen & Osmundsen, 2005)

An important role in the NORSOK process was played by the government, where a larger flexibility was the goal for regulation and management of area. Specifically, the duration of the initial extraction permit, return of the area and the length of the new extraction permit after the initial permit was expired. A line in the Petroleum law §4-2 (Olje- og Energidepartementet, 1996) opened the possibility for companies to get a simplified treatment. This basically means that for some projects, substantial contracts can be entered before the PUD/PAD is approved, at the company's own risk. Because of a rise in smaller projects and projects that was going to use existing infrastructure, and so did not require any "from above" coordination, the Storting wanted the option to do a simplified evaluation of the PUD/PAD. This was opted for in a statement in Innst. S. nr.104 (1991-1992).

2.2 Projects on the Norwegian Continental Shelf and Some Technological Developments

A paper by Reid, Yost and Russel investigates the cost overruns of large petroleum related projects and found that the overrun on average was as large as 30-40%. They attribute part of this overrun to high risk in E&P operations, and the other part was attributed to organization of project development. Their solution to the problem of cost overrun in large petroleum related projects are summarized in the following aspects that they distilled from looking at successful projects (Reid, Yost, Russell, & Cheung, 2016):

1. Alignment of business goals for all the involved parts
2. Clear definition of responsibility for more integrated modular deliverables.
3. Genuine interest of every party having a successful business.
4. Commitment to delivering and collaborate loner that the life of the facility.
5. Obsessive communication and action that supports controlled and evaluated change decisions.
6. A commitment to eliminate over-management and complexity wherever possible.
7. Selection of experienced, key players that includes operational experience and regional knowledge as well as proven agility in best practice leadership.

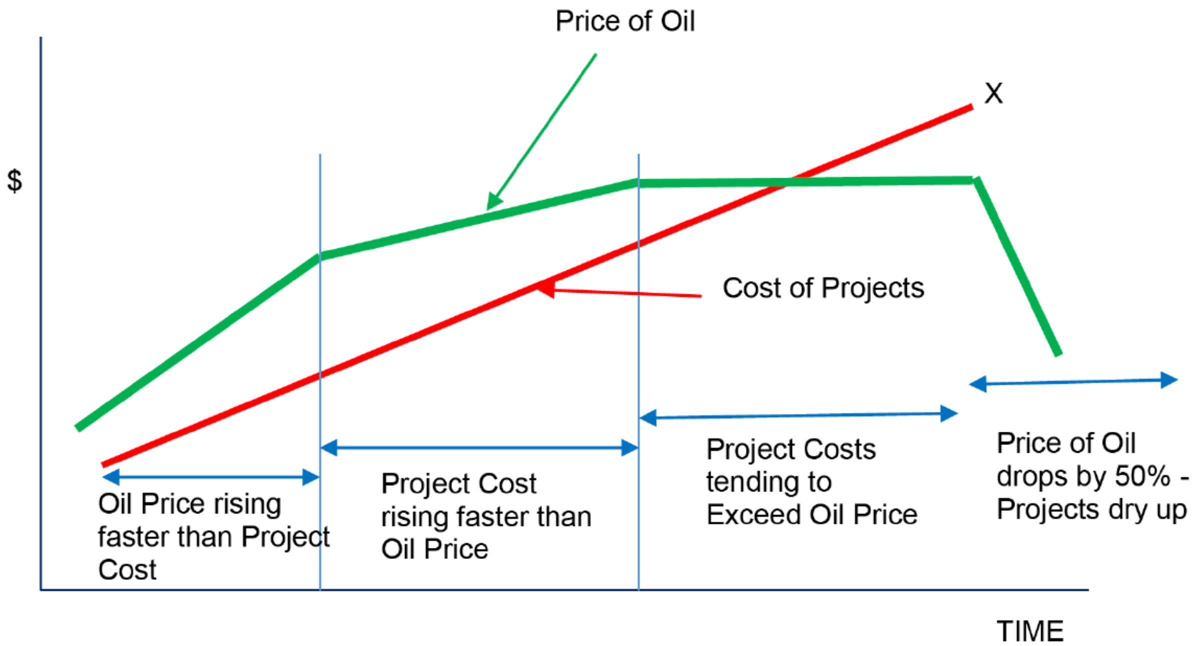

Figure 2-5 Simple illustration of business cycle (Reid et al., 2016)

As illustrated in Figure 2-5 the cost of new projects tends to inflate when there are good times in the industry.

In 1999, a group of experts[12] was chosen to analyze the investment development on the Norwegian continental shelf. This selection of experts was made by *Olje- og energidepartementet*[13]. The report found that projects that got their PUD[14] approved in the 1994-1998 period had an average cost overrun of 13 percent. For the 13 projects that was investigated, the average cost overrun was 27 percent. The cost overrun is measured as the difference between the original estimate in the PUD and the estimated final cost at the end of 1998, as most of the projects was not finished in this period. The report uses the Norwegian consumer price index to adjust its numbers. The findings in this public investigation was published in the NOU 1999:11 report (Kaasen et al., 1999). The NOU 1999:11 uses both quantitative and qualitative information. The report argues that using numbers alone cannot answer the question of why initial estimate of project costs were increasing in the period from 1994-1998.

The expert group concluded that the reasons for the cost overrun in large projects approved between 1994-1998, was:

Low pricing of risk, lacking foundation for decisions. This low pricing of risk was sometimes driven by optimism caused by a positive trend in the sector.

Drilling contributed to the cost overrun. Lack of planning and a clear plan for drilling, accompanied by high demand for drilling rig resulting in high rates and low productivity on the part of drilling.

A technological shift took place during this period. Implementation of the floating production facilities with subsea wells contributed to considerable uncertainty that was not accounted for in the budgeting.

The new structures in project execution did contribute to some of the cost overrun, because the suppliers did not have experience with the new project implementation. The high activity level amplified the problem. (Kaasen et al., 1999)

In 2013 the Norwegian Petroleum Directorate (NPD) wrote a report that is modeled after the NOU1999:11. Projects that had an approved PUD in the years 2006-2008 and an investment scope above 10 billion was investigated in this report. This report concluded that for all the project that had an approved PUD between 2007 and 2013, the average cost overrun was 14%, 49,3 Billion NOK in 2013 value. Based on the qualitative review of project With PUD between 2006-2008 and an investment scope above 10 Billion NOK, the NPD reported that the reasons for the cost overrun in this period was to a large degree similar as the reason reported in NOU1999:11. Shift in technology seemed not to be a contributing factor, but exaggerated

[12] Knut Kaasen, Iulie Aslaksen, Stig Bergseth, Erik Grønner, Arild Hervik, Bjarne Moe and Atle Tranøy
[13] Olje- og energidepartemang is the Norwegian Ministry of Petroleum and Energy.
[14] PUD is a document that describes the building and operations on a field, this must be approved by the government before commencing a project and it must contain, amongst other things, a description of the economic parts of the project. PUD’s are kept from the public for 20 years after its approval.

optimism fueled by unrealistic ambitions, underestimations of risk and a high activity level was given as part of the problem. Also, the transition to design and build contracts that represented new and inadequate knowledge in 1998, was reported to be part of the problem (Norwegian Oil Directorate, 2013).

A paper by Dahl, Lorentzen, Oglend and Osmundsen investigates the effect of the business cycle on cost overruns. By identifying important global and local business cycle factors thy derived what was the largest cost drivers in the petroleum industry. They compared the period of large cost overrun in the 1990s with the period before the oil price bust in 2014.

By looking at the NOU1999:11 and a report from 2013 by the Norwegian Petroleum Directorate which both investigates the periods with large cost overrun, they are able to identify some causes for the cost overrun. One interesting statement in this report is that when oil prices go up, the speed of drilling goes down[15] and the rig rates goes up. Between 2000 and 2013 the rate for drilling rigs increased by 312%, this was combined with a large reduction in productivity, this lead to an explosion in drilling costs. In the recent downturn it has been a large decrease in drilling rates and an increase in drilling speed. This fact suggest that drilling costs are responsive to the business cycle. This is caused partly by the scarcity of certified rigs in in boom periods. Arguably it might be qualified personnel that is the scarce factor (Dahl, Lorentzen, Oglend, & Osmundsen, 2017).

Also, in the NOU1999:11 it was reported that lack of qualified personnel was among the primary reason for cost overrun when developing projects.

Investments in development projects are less responsive to fluctuations in oil and gas prices than exploration. This is partly due to the long lead time in development projects and partly due to the high risk associated with exploration makes it more price sensitive. Moreover, large development projects, often referred to as megaprojects, can be hard to cancel due to the large initial investments.

According to this report, the labor marked provides the best indicator for the business cycle. In this report they point out that, while tax policy can in principle be used to stimulate the industry in low activity years and curb the high activity years. This can be hard to do as timing is impossible in regard to curbing activity before peak activity. this is illustrated by changes to the tax law in 2013 that reduced tax depreciation to curb investments. This came at an unfortunate time as the effect of the changes to tax policy compounded with the bust in oil price and reinforced the downturn.

Idle capacity in the supply marked imply high competition which in turn implies higher average quality and lower prices. (Dahl et al., 2017).

One example of the positive effects of the downturn in the business cycle is Sverdrup project which has had a cost underrun.

[15] Drilling can represent up to 50% of the total cost of a project.

2.2.1 Developments and Expansion of the Industry Scope

In the 1990s the technological development was large, and the time between prototyping to an implemented technology was short.

The development was most substantial in the following areas;

- **Floating production**, multiple large floating production platforms where built in this period. These production platforms borrowed technology from shipping and ship building. Some facilitating technologies where furthered developed, that is; dynamic riser, size and pressure rating of the swivel increased, transportation of well stream over longer distances where made possible and complex subsea systems facilitated new systems.
- **Single lifting**, 11 projects in the period 1994-1998 where platforms that could be lifted in place in one lift. This this allowed for less complex and time-consuming commissioning.
- **Drilling- and well-technology**. Large progress in drilling and well technology allowed for more accuracy and range when drilling. The progress in this area did allow for more flexibility and more options for production that would be economically viable when developing a reservoir.
- **Processing facilities**, the equipment was to a large degree the same in this period as earlier. But some of the improvement comes from more compact systems with better control systems. Some improvement was done regarding pollution, manly in lowering NO_x and H_2S emissions.

The favorable developments in the oil industry after the NORSOK-process in the 1990s where accompanied, or in some cases made possible by substantial technological improvements (Kaasen et al., 1999).

When comparing this to the oil crisis in the 2014-2017 period, the technological improvements that is most prevalent and seams to play a large role in making more of the resource available, economically viable and keeping risk of accidents at a minimum is information technology. Development of censors that can measure most relevant physical factors, communication infrastructure that makes it possible to transfer large quantities of data in real time to any location, and processing power couplet with artificial intelligence (AI) that makes it possible to process large datasets very fast.

Bellow there are some examples of improvements that are occurring or is projected to occur from this development.

Autonomous ships/platforms. This technology could make transportation of oil and gas from the fields cheaper, thus making new resources available. Also supply shipping might get cheaper. It might seem farfetched with an autonomous fleet that can provide necessary logistics on the NCS. But Wartsila has developed an automatic docking system for large vessels (Sætre, 2018) and in a study conducted by the consulting company PwC, they found that there is an overwhelming consensus amongst the shipping companies that the shipping industry will be autonomous in the conservable future (Hermansen, 2018).

Centralized control. Less personnel might be necessary to man drilling rigs or production rigs in the future. Statoil is currently working on establishing two centers in Bergen that is going to serve 40 platforms and oil installations. Statoil claims that this will lower costs by 15,5 billion NOK over the next five years and that the cost of establishing the center is between 50 and 100 million NOK. Additional benefits are increased safety, fewer risky operations and higher operational quality, partially because it will be possible to detect challenges and predict problems in production before they occur (Angell & Ekanger, 2018).

Information collection and processing. Manager in Lundin, Kristine Færøvik stated in an interview with Sysla the Edvart Grieg platform is equipped with 6000 censors that continuously collect data from the state of the equipment and the reservoir (Myrset, 2018). CEO of Aker BP, Karl Johonny Hersvik, presented the challenges and the possibilities that comes from digitalization in an interview with Sysla. He states they have 200 000 censors divided on 5 platforms that continuously collect data (Søgnen, 2018b). Solution Seeker is a company that specializes in AI (Artificial Intelligence), they have been hired by Aker BP to interpret the data that is streamed from Aker BP's platforms and to predict the best possible method for producing the resources (Søgnen, 2018a).

The Barents Sea contains approximately 36% of the remaining resources on the NCS. It is estimated that there are 3089 million Sm3 oil equivalents, including undiscovered resources. It is two producing fields in the Barents Sea and A PUD for Johan Castberg has been delivered. John Castberg contains ca. 89 million Sm3 oil that canb e produced, and 11 million Sm3 gas. Before the bust in oil prices, the field had a price tag of 100 billion NOK and needed an oil price of 80 dollars per barrel to be profitable. In December 2017 Teknisk Ukeblad reported that the project would cost only 49 billion NOK and be profitable at a price of 35 dollars per barrel of oil (Taraldsen, 2017). The field resides 110 km north of Snøhvit which was approved in 2002, originally had 224 million Sm3 gas and has cost 12,5 billion to develop and has estimated future investments up to 31 billion from 2017. Snøhvit does not have any residual capacity for gas transport before after 2040, according to Njærheim (Andersen, 2014). Goliat is the second field that is producing in the Barents Sea, it was approved in 2009, has costed 47,7 billion with predicted future investments to be 5,4 billion from 2017. The field contains 31,5 million Sm3 of oil (Norwegian Petroleum Directorate, 2018). The Barents Sea has a sever lack in infrastructure, this combined with the large distances from fields to gas markeds, makes initial development more expensive and with an uncertain future for gas and oil there are some debate whether the Barents Sea will be economically viable. According to Njærheim, it will be at least 30% more expensive to develop fields in the Barents Sea compared to developing a field in the North Sea or Norwegian Sea, and there can be much to save if oil companies cooperates in developing infrastructure (Andersen, 2014). A report from Rystad Energy in 2014 reported that the development of fields in the Barents Sea would require an oil price above 60 dollars per barrel (NTB, 2015). The Barents Sea has seen an increase in exploration wells drilled, this indicates an optimism about the area, numbers of exploration wells are displayed in Figure 3-29.

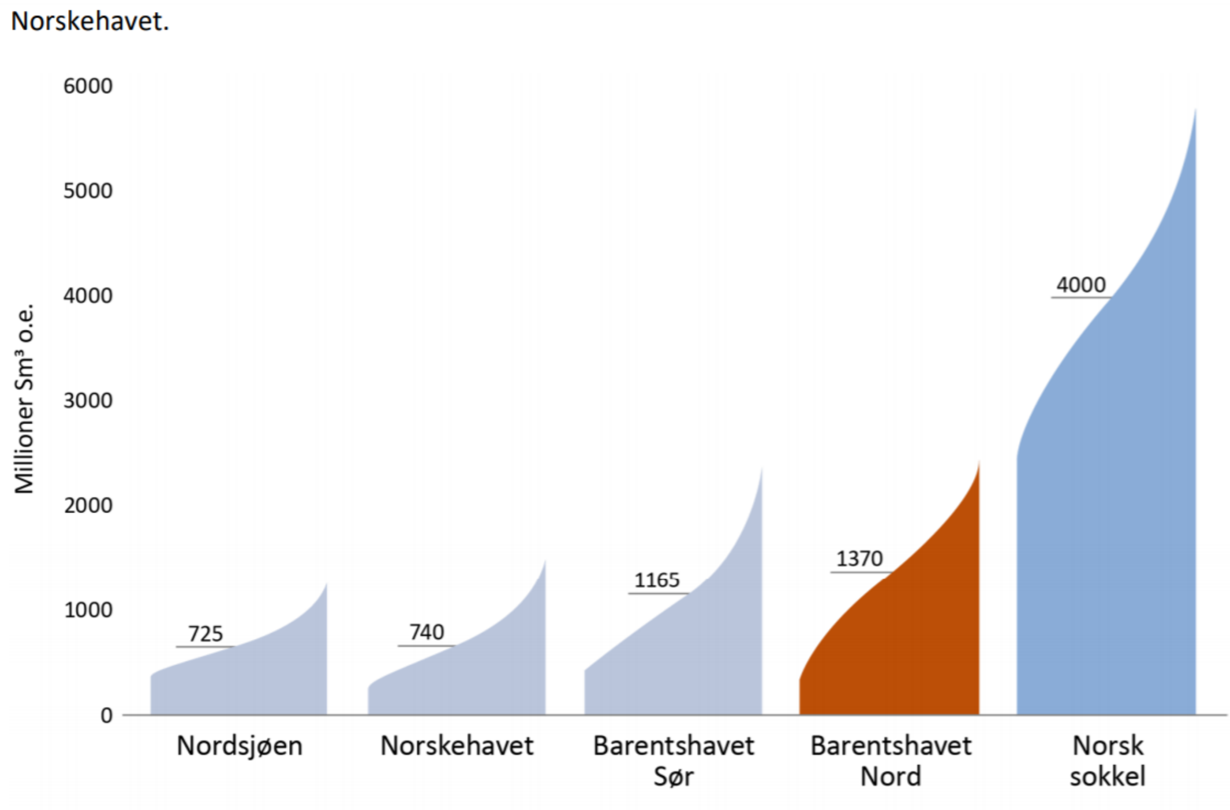

Figure 2-6 Estimated undiscovered resources on the Norwegian shelf (Oljedirektoratet, 2018).

It has been estimated that almost two thirds of the resources on the Norwegian shelf is in the Barents Sea (Figure 2-6). The tapered tops of the bars in Figure 2-6 represent the uncertainty in the estimates.

Carbon Capture and Storage (CCS) is currently investigated by companies and government as a possible new industry for Norway. The goals that has been established in the Paris agreement points to carbon capture and storage as a possible large part of the solution. By utilizing existing infrastructure in the North Sea, storage of co_2 in old reservoirs can become a new industry in Norway. Also, hydrogen production from natural gas, with ccs can be one of the game changers in regards to decreasing co_2 emissions according to Karl Eirik Schjøtt-Pedersen (Andersen, 2018). A report from SINTEF finds that full scale carbon capture technology has the potential to create 30 000 jobs in Norway (Størset, Tangen, Wolfgang, & Sand, 2018).

2.3 Consolidation in the Petroleum Industry

As the oil price seem to have at least one volatile period each decade from 1970 and forward until today, the petroleum related companies have had to adapt to ensure their ability to compete on the global marked.

The petroleum industry is subject to complex regulations that require substantial efforts to assure quality and compliance. And as all low growth industries, competitions and margins are tight. In addition, there is a large risk involved in this industry, both from environmental concerns, but also from the oil price. In 1998 a “round” consolidation was kicked off when British Petroleum merged with Amoco, followed by an acquisition of Mobile Oil by Exxon (Gebauer & Segev, 2000).

A paper written by Solomon O. Inikori, Mahendra Kumar Kunju, and Omowunmi O. Iledare in 2001 investigated this. They noted that when oil price increases, firms have problems making changes that apply quick, decisions and investments that is meant to utilize higher oil prices will only pay off in the long run. This makes the booming period in oil prices a period of investments based on the high oil prices, and finally when the supply catches up to the demand, and the oil price drops, smaller companies are not able to carry the cost of their optimistic investments. This is especially true in areas where there are an large cost barrier for exploration and development, such as the North Sea (Inikori, Kunju, & Iledare, 2001).

“Bigger is better” according to an article written by Ernst and Steinhubl and published in *The McKinsey Quarterly*. The megamergers that occurred in the late 1990s, after the bust in oil price, was consummated because size, relationship and structural considerations continues to bestow considerable economic advantages in regions with few competitors, the right to own and access reserves is limited, and capital and risk requirements can’t be met through financial markets. In their article, they point out that the new marked leaves room for specialized companies to compete in “niche” market segments (Ernst & Steinhubl, 1999).

In 2007, two of the largest Norwegian Production companies, Statoil and Hydro, merged. The argument against was that there would be less competition, and this would not foster creativity and good solutions. The argument for was that the companies, together, would wield greater human capital, be capable of large and more complex projects and that this was needed on the NCS which was becoming increasingly hard to develop (Equinor, 2018).

Time for consolidation was the title of the report from Norsk Olje og Gass in 2014. They pointed out that even though there was high oil prices, the profitability in the international oil industry in 2013 was equal to the profitability in 2002 (Norsk Olje og Gass, 2014).

2.3.1 Developments in Kvaerner and Aker between 1984 and 2017

Kvaerner and Aker are among the biggest supplier companies in Norway, and they have been in on the project development side of the petroleum industry since 1966. Their history of mergers and acquisitions can be used as analogy to the consolidation trend that occurred in the late 1990s.

Through the 1980s, Kvaerner Engineering, the Kvaerner yards and Kvaerner's manufacturing facilities won contracts with larger and more complex scopes. In 1984 Kvaerner establishes an R&D department and subsequently makes some important steps in subsea technology.

Between 1986 and 1988 Aker bought Astrup Høyerm and Norwegian Contractors, and merged with Norcem, these moves increased their capacity to handle the large construction projects that was being conducted in this periode. Trough the 1980s and 1990s, Aker's offering included units like Aker Drilling, operator of drilling platforms, Aker Base, a leading operator of supply bases and logistical services, Aker Subsea with underwater solutions, units operating vessels for seismic surveys, units manufacturing drilling mud, units for studies and FEED work, etc.

At the end of 1996, Aker acquired the Norwegian based Maritime Group, including subsidiaries such as Maritime Hydraulics, Maritime Well Services and Maritime Pusnes. Aker's total oil and gas activities were placed in a separate, publicly listed company: Aker Maritime, with Aker RGI as the main shareholder.

In the year 2000, Aker buys a large share post in Kvaerner. Due to Kvaerner's liquidity problems throughout the next years, Aker was able to emerge as the largest shareholder in Kvaerner. In 2004 Aker's and Kvaerner's shipyards was merged into Europa's largest shipyard corporation. Between 2005 and 2007 multiple companies spring out of Aker; Aker Drilling, Aker Biomar, Aker Floating Production, Aker Exploration, Aker Oilfield Services and Aker Clean Carbon.

In 2008 Aker Kvaerner changes name to Aker Solutions. Aker Exploration and Det Norske merges in 2009, Aker is the largest shareholder after this merger, but the company retains the name Det Norske. Aker Solutions devoted its aim toward service and supply and the EPC (Engineering, Procurement and Construction) part is given to Kvaerner which became a separated company in 2011. And in 15.10.2014 Det Norske acquires Marathon Oil (Kvaerner, 2018).

2.4 Fiscal Framework for Petroleum Production in the Norwegian Sectors

Act 29 November 1996 No. 72 lays an important foundation for all industries related to the petroleum sector. §1-1 in the petroleum law states; the Norwegian state has ownership of the subsea petroleum resources and an exclusive right to manage these resources. No one except the government can exploit petroleum resources without an permit. (Olje- og Energidepartementet, 1996).

Chapter 3 in the Petroleum law comprises production permits. §3-1 establishes the rules for opening new geographical areas for production. In this law it is stated that there must be a consideration of all interests that can be affected by the petroleum industry. There shall be an evaluation of environmental concerns and the economic and social effects the industry may have on the area.

The production permit can be given to a legal person in Norway or in an EEA[16] country. The operator on a production license must be approved by the department. A production license is given for up to 10 years, and if the license is given for less than 10 years the department can prolong the license within the frame of the original 10 years. If the license owner operates in accordance with the regulations in §3-8, he can demand that the license is extended up to 30 years after the initial production license, and in some special cases up to 50 years.

Chapter 4 in the petroleum law describes how the petroleum recourses must be produced. The essence of this chapter is that production of petroleum resources must be in a manner that is economically healthy and that does not squander any of the resources.

To enforce this concept, the license holder must deliver a PUD, and this must be approved by the ministry. This plan must contain detailed descriptions of the entire life cycle of the project. One important aspect of §4-2 is that no considerable contracts can be entered into before the ministry has approved the PUD, unless there are given permission to enter into contracts before the ministry has approved the PUD. In NOU1999 it is pointed toward the possibility to enter into contracts before the ministry approves the PUD as one of the most important steps toward speeding up projects. This option is given with reservations, as the ministry still has the option to turn down the project. In practice this option is used frequently (Kaasen et al., 1999).

§4-4 forbids the flaring of petroleum resources other than what is necessary to maintain safe production, unless the ministry allows it. This rule was first introduced in 1971. This has had two positive effects, one is less carbon emissions from Norwegian petroleum production compared to other producers[17], and second positive effect is increased recovery of oil because approximately 30% of the gas is reinjected into the reservoir. This can be an important reason for why the Norwegian petroleum industry has the highest recovery rate in the world (Rasen, 2011). In §4-8 it is stated that the ministry can allow installations, that is covered in §4-2 and §4-3, can be used by others if rational production, or socioeconomic effects suggest that is the best option, and the ministry decides that it is not an unreasonable displacement of the licenser owner.

§4-10 lays the terms for the area fee and the production fee. The function of this fee, according to a letter from the Ministry of Petroleum and Energy, is to act as an incentive to ensure that the area is explored in an effective manner, that the production is initiated as soon as possible, and that the production lifetime of existing fields is extended if possible. The fee is not active during the initial exploration period and the fee is deductible against income tax. Area fee before 2007 started at 7000 pr. Km^2 and over a 10-year period increased to 70 000kr pr. Km^2. The combination of relatively low fee after tax, and a long escalation period for the fee, it was believed that the fee did not affect the decisions by the license owner. In the start of 2007 there was some changes to the fee, the escalation period was decreased from 10 to 3 years and the amount was increased to 30 000 the first year, 60 000 the second year, and finally 120 000 NOK

[16] European Economic Area
[17] Norway only burn 0.3% of the gas produced, while Russia burn 25% in 2011(Rasen, 2011)

per. Km^2 each year until the PUD is delivered[18]. The Barents Sea had a reduction in the area fee, but the reduced rates were removed in 2007 to ensure that this area has the same incentive for effective exploration and development. Number of exploration wells drilled in the Barents Sea is displayed in Figure 3-29 (Olje- og Energidepartementet, 2006).

The production fee only applies to installations which PUD was delivered before 1986. This fee was calculated according to the value of the petroleum that was produced. This was a form of gross tax. This way of taxing the production moved risk from the government and over on the producers. Although the government would receive royalties early, it did not promote optimal development and full exploitation of oil reservoir (Askheim, 2013a).

In Norway the corporate tax rate was 24 percent in 2017 and in 2018 it will be 23 percent. While the corporate tax rate has been decreased, the special tax that applies for income from extraction, treatment and pipeline transportation of petroleum resources has been increased from 54% in 2017 to 55% in 2018 (Finansdepartementet, 2017). This means that exploration and production companies on the NCS operates under a marginal tax rate of 78 percent.

Net cashflow from the petroleum industry to the government is displayed in Figure 3-20.

The tax law for petroleum activities uses the normal tax laws that apply for all companies in Norway as a starting point, but for petroleum activities there are given special considerations.

Norm pricing is one, this is a rule that is meant to hinder international companies and companies that are close to each other to reduce the tax cost through internal pricing and increased use of resources to achieve a lower tax cost. It basically means that the government can decide the price for products that are subject to these rules based on the market value. This means that companies often use norm price both internally and externally when selling, to avoid being taxed for income they did not have. Gas, LNG and condensate is taxed at actual sales price, but the government keeps track whether it is sold at market value.

Depreciation of pipelines[19] and production devices[20] that is within the geographical area of the petroleum tax law is depreciated linearly by up to 16.66 percent. For some facilities in the northern part of Norway, the depreciation rate is 33.33 percent, it is by this date only the Snøhvit Field that is affected by this rule. The start point for depreciation is within the same year as the investment is made, this is more favorable than land rules where the start point is in the same year as the device is being used.

There are also special rules for the *deductions from financial expenses,* the petroleum tax law distinguishes between interests and currency loss/earnings on loans and other financial posts[21]. The deduction from financial cost in the Continental shelfs tax regime (78%) amounts to the

[18] The area of a typical license usually ranges between $500km^2$ and $100km^2$, but the area can be much larger or smaller (Norwegian Petroleum Directorate, 2018).
[19] This expression contains; receiving and shipping facilities on land. Refining facilities is not included, sometimes it is difficult to decide whether the facility is subject to land or offshore depreciation rates.
[20] Production devices include; drilling and production platforms, housing platforms and tanks for petroleum storage. Other facilities on land, such as; buildings, vehicles and bases are subject to normal rules even though they are used only regarding petroleum activity.
[21] Other financial post is subject to the normal corporate tax rate which is 24% in 2017 and 23% for 2018

ratio between 50% of depreciated value of the object that is used and the average interests carrying loan rent cost +/- currency changes.

The formula is:

$$Deduction = (Rent\ cost +/- currency\ earning/loss) \times \frac{50\% \times Taxable\ value\ of\ object}{Size\ of\ loan}$$

All *explorations costs* can be written as expenses. If the exploration costs exceed the ordinary taxable income, it is possible to receive a direct payout[22] from the government equivalent to the tax value. The part of the deficit that is refunded cannot be carried forward. This is a scheme that is meant to make it easier for new companies to establish on the NCS and compete with companies that are already in tax position.

The d*eficits* from production and pipe transportation can be carried forward with no limitation on time. When realizing of the company, or a merge between the company and a different company, the deficit can be carried forward by the company that is taking over[23]. When seizing of a business that is affected by the special tax law, it is also possible to demand the tax value of its deficit from the government. It has also been normal to leave the deficit in an E&P company when it is merged, the deficit is left in the company that is not continued and the tax value of this is demanded from the government.

Investments made under the special tax law for the petroleum sector are subject to a *free income*[24] rule, this says that 21,2 percent of the investment cost is not taxed. The free income is calculated from the first 4 years after the depreciation of the means of production is started. This means that 5,3% of the investment cost is not taxed the 4 first years, this can be carried forward (KPMG, 2017). Before 2013, the free income was 30% divided over 4 years (Stortinget, 2013).

Calculations of petroleum tax are:

Income (Norm price)
-Operating costs
-Deductions (linear over 6 years)
-Exploration cost, deductible, deficit and ending costs
-environmental fee and area fee
-Net financing costs
=Basis for ordinary tax (23% in 2018)
-Free Income (5,3% of investment over 4 years)
=Basis for the special petroleum tax (55%)

[22] There are some limitations to what can be included in refundable exploration cost. For example, the financial costs, area fees, marketing and pre- qualifying etc. are not included.
[23] This only applies if the deficit is written after 2001.

2.4.1 Fields and PUD's

The definition of a field, given by Norwegian Petroleum Directorate (NPD) is:

"A field is a discovery, or several discoveries combined which the licensees have decided to develop, and for which the authorities have approved a plan for development and operation (PUD) or granted a PUD exemption." (Norwegian Petroleum Directorate, 2018)

The NPD keeps information on all field publicly available on their fact pages, and this information can be used to derive some trends or developments in the industry.

The Norwegian Petroleum Directorate has issued a guide for PUD/PAD, this guide establishes all aspects of the PUD that is of interest to the government. This document also contains certain criteria that a project must answer to.

Important criteria from this guide is;

The profitability of the project must be calculated in net present value using a 7 percent rate. In this case environmental fees shall be included in the calculations. NOU2000: 18 also uses 7% as the baseline for new projects. The 7 percent number is supposed to reflect the risk associated with the investment.

The projects that are exempted from an evaluation and approval from the Storting must not have an estimated cost above 20billion NOK, the project must not have any notable socioeconomic sides or principal sides, and each project must show socioeconomic profitability and be resistant against changes in oil and gas price.

2.4.2 Socioeconomic Considerations that Influences Decisions, Regulations, and Development

It is impossible to derive one single goal for the industry that has been aimed at by all the different government in all different periods during the 50 years the industry has been relevant. Different governments have weighed the importance of the points mentioned above differently.

In some cases, there is a question of finding the right balance between protectionism, how much environmental risk should be taken, and whether the government should initiate countercyclical means to mitigate the boom and bust in the business cycle. The timeframe that is used as a foundation in evaluating different policies will have a large effect on what policies will help the industry in the given time frame. For example, in the short run a protectionist policy, where national suppliers are prioritized, will create more jobs in Norway in the short run, but it might weaken Norwegian ability to compete on the global marked.

NOU1999:11 (Kaasen et al., 1999) presents two types of cost overrun in development projects.

One is that increases in cost reduces the total profitability of a project, but the increase in cost does not change what was the optimal project design in terms of opportunity costs for the resources.

The second type of cost overrun is the type that comes from suboptimal use of resources. The first type of cost overrun leads to a smaller rate of return that leads to a smaller socioeconomic contribution, but it has no effect on what was the optimal use of resources. The second type of cost overrun consists of incomplete or bad cost information prior, that leads to wrong use of resources seen post.

Perfect information is impossible, and it would in most cases be expensive to obtain. A decision that revealed itself to be not optimal could have been optimal based on the available information at the decision time. Therefore, an analysis of profitability based on hindsight is not that interesting when the cost overrun is driven by occurrences outside of the decisionmakers control. The interesting question is whether enough is done to collect information. This would have to be measured in what extra information would cost and what that extra information is worth.

An increase in payouts to national suppliers are not a socioeconomic loss per se, but rather a redistribution of wealth from the owners of the project to the sub suppliers. The real socioeconomic cost arises from the suboptimal use of scarce recourses that could have alternative uses elsewhere in the economy. When it comes to import of factors to the industry, this is a net cost to the society. Also, when there is a short-term capacity shortage, foreign capacity must be rented, and this is a socioeconomic cost. Low input estimates, or low estimates of the opportunity costs of the inputs to a project, will result in an underestimation of the socioeconomic costs and thus leading to lower socioeconomic profitability relative to original estimates.

When cost overrun is driven by circumstances that are outside of the decisionmakers control and the overrun does not have negative socioeconomic effects, there is not much to do from the view of government. The discussion should therefore be concentrated on the cases where cost overrun leads to sub optimal socioeconomic resource use.

In corporate finances marked prices are used in the calculation of the profitability of a project, or the cost overrun in a project. In a socioeconomic calculation of a project, or the cost overrun, the opportunity cost of the resources that is used in the project. In a perfect marked the opportunity cost used in the socioeconomic calculation should be equal to the marked prices, but there is marked deficiencies due to for example taxes that give incentive to operate strategic in relations to the taxes, also monopolistic pricing can occur. In the NOU1999:11 it is assumed that the competition ensures that prices are close to marked prices, thus ensuring that there are no large skew due to tax law and that there is a congruence between corporate and socioeconomic calculations of cost.

Table 2-1 Socioeconomic Calculus and Additional Corporate Cost for Actors in the Oil Sector (Kaasen et al., 1999).

	Partaker	**Income**	**Costs**
1	Oil companies (including. Statoil and SDØE[25])	Sales from oil and gas. Daily penalty/withdrawn bonuses. Reduced oil tax.	Cost overrun oil rig building. Interest expenses from delays. Additional cost from; operations, management/planning, drilling and subsea installations.
2	Total contractor	Income increase from oil rig. Extra shipyard subsidies.	Daily penalties/withdrawal of bonuses. Extra salary cost platform building. Extra expenses other goods. Other extra recourse effort (total contract)
3	Sub supplier	Added value underwater installations. Extra income other goods.	Extra resource effort Sub supplier.
4	Drilling companies	Added	Extra resource effort drilling
5	Workers (Platform builders)	Extra salaries from platform building	Extra resource effort work. Extra cost to health
6	State	Taxes, fees dividens from Statoil and SDØE	Reduced oil tax due to cost overrun. Extra shipyard subsidies.
7	Local community surrounding platform builder		Local environmental disadvantages from the extra burden.

In Table 2-1, the stakeholders in the petroleum industry is listed along with the income and cost.

[25] SDØE (State Direct Economical Commitment). Was an institution that was created when Statoil's share in most production licenses was divided between Statoil and the state in 1985. When Statoil was partly privatised in 2001, Petoro received 78.5% of the shares in SDØE (Askheim, 2013b).

3. Presenting and Discussing the Data

3.1 The Price of Petroleum Products

The price of petroleum products, mainly oil, has a volatile history. The price of oil is on a fundamental level determined by the global supply and demand. But, because oil has been, and still is a vital commodity for any industrial nation, the production and distribution are subject to political interference.

According to Kilian (Kilian, 2017), Contributing factors to the steep decline in prices was; large producers increased their output[26], negative shocks to storage demand, signaling expectations of lower future oil price, and negative shocks to consumption demand of oil, according to (Kilian, 2017).

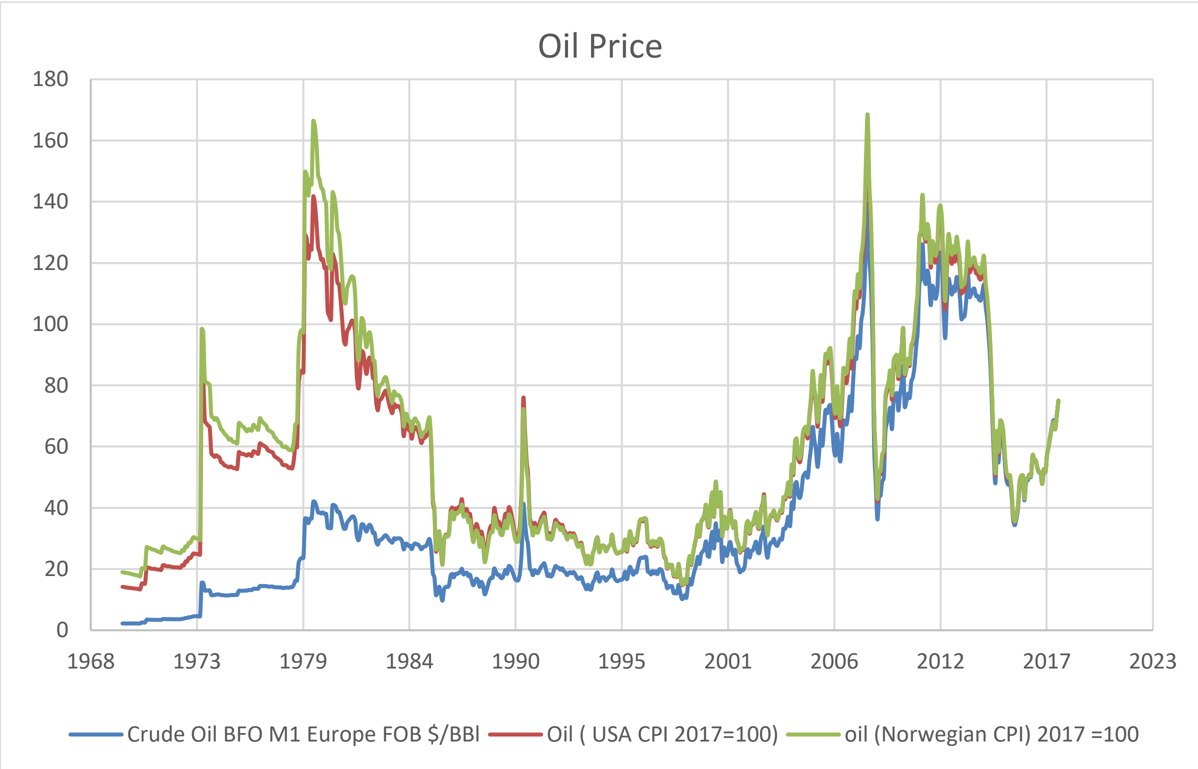

Figure 3-1 Historic Brent Oil Price ("DataStream," 2018).

In Figure 3-1 the oil price is displayed in nominal value and as a deflated value using the Norwegian CPI. The Norwegian Consumer Price Index is a common deflator as it measures the cost of living for consumers in the Norway, and thus it holds some merits as a measure of change in the value of the Norwegian krone (NOK). Because the relationship between NOK and the US Dollar has been relatively stable between 1970 and 2017 this thesis assumes that

[26]In the period from 2008-2015 U.S production increased by 4.3Mb/d, Iraq increased by 2.07Mb/d, Saudi Arabia increased by 1.23 Mb/d, Russia 0.79 Mb/d and Canada 0.79 Mb/d.

deflating the oil price with Norwegian CPI gives and accurate real price of oil. The American Consumer Price Index is also displayed, and there is a divergence in some periods, but this does not affect the analysis made in this thesis.

The NOU1999:11 uses the Norwegian CPI to deflate the cost of development projects. Other indexes could be used, such as a GDP deflator. This would not yield a substantially different result. For a more accurate measure of the real oil price from the view of the supplier of oil, an index of the cost of producing oil would be the most accurate. In Figure 3-4 the relation between Dollar and NOK is displayed.

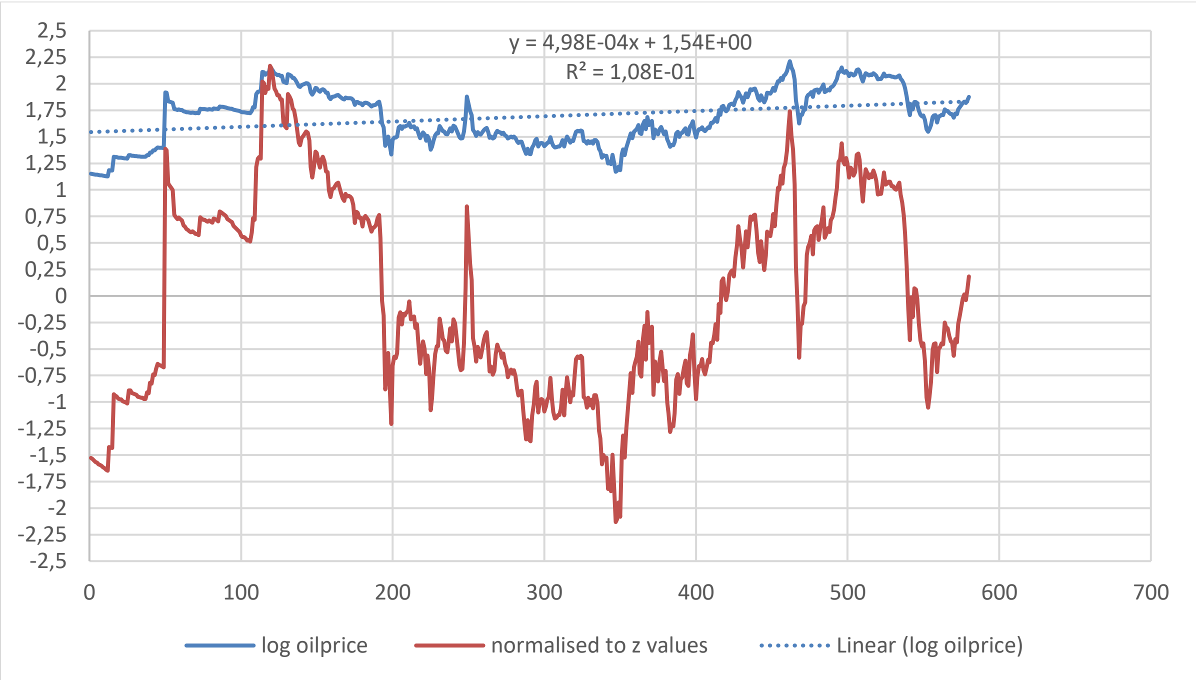

Figure 3-2 Logarithmic Trend

In Figure 3-2 a linear trend is fitted to the logarithm of the price series of monthly datapoints using Excel, the series starts in 01.015.1970 and ends in 15.04.2018. Assuming the CPI deflator has revealed real oil price, there could arguably be applied a weak positive trend, the R^2 =0.10 implies the trend only explains 10% of the actual oil price, thus making this trend highly questionable. It is evident from the graph, and from historical accounts, that geopolitical factors can have a large influence on the oil price, as discussed in chapter 1.4.5. These situations can be hard to predict and makes analyses of future oil price based exclusively on quantitative measures difficult and inaccurate. Especially long-term predictions carry a lot of uncertainty. Some qualitative regards should therefore be made to increase the accuracy of the analysis.

Normalizing[27] the price using the trend displayed in Figure 3-2. From this one could argue that oil prices have been too high, and a value of ca. 75 dollars per barrel is more in the range of an

[27] Use actual price subtract expected price derived from trend and divide by standard deviation.

expected value in 2017. Also, locking at the entire period from 1970 and till today, it is apparent that the oil market was in its worst shape in the late 1990s. In Figure 3-2 the Z values are displayed.

One characteristic of the busts in oil price in 1986, 1998, 2008 and 2014 is that changes in Z-value, over a relatively short timeframe, is large. The interesting thing about oil prices is that the prices might have a slow, but steady rise. And in most cases, it has a quite sudden and drop.

The simplified figures in Figure 3-3, illustrates the booms and busts in oil prices. The figure displays the changes in the 1-year average of the oil price.

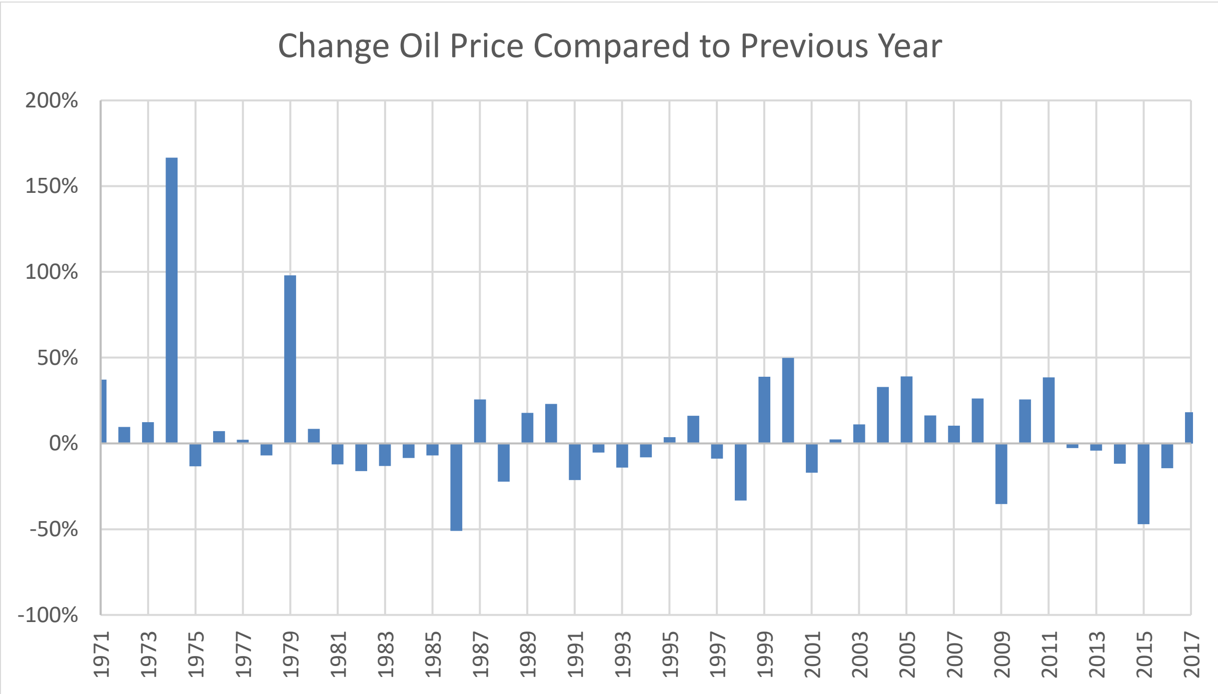

Figure 3-3 Displays the 12 Month average oil price change compared to previous year.

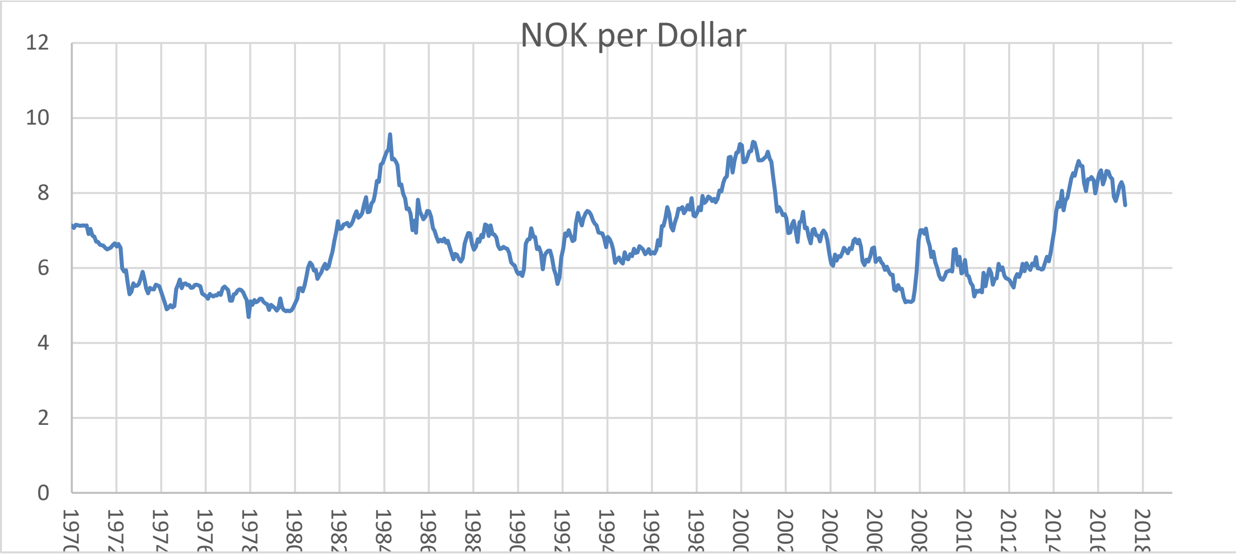

Figure 3-4 NOK per Dollar (Bank of England, 2018).

The NOK to Dollar exchange has been relatively stable, from 1970 to 2017, average exchange has been 6,67 with a standard deviation of ca. 1, the NOK per Dollar exchange rate is displayed in Figure 3-4.

When looking at the yearly average of both the price of dollar, measured in NOK and the cost of oil measured in Dollar, from 1978, it appears that the two has a negative correlation of 0.5, the correlation is displayed in Figure 3-5. The oil price has not been attributed a trend for this calculation, but it is deflated using the Norwegian CPI. The strong negative correlation does work as a hedging mechanism against the oil price. The correlation is displayed in Figure 3-5.

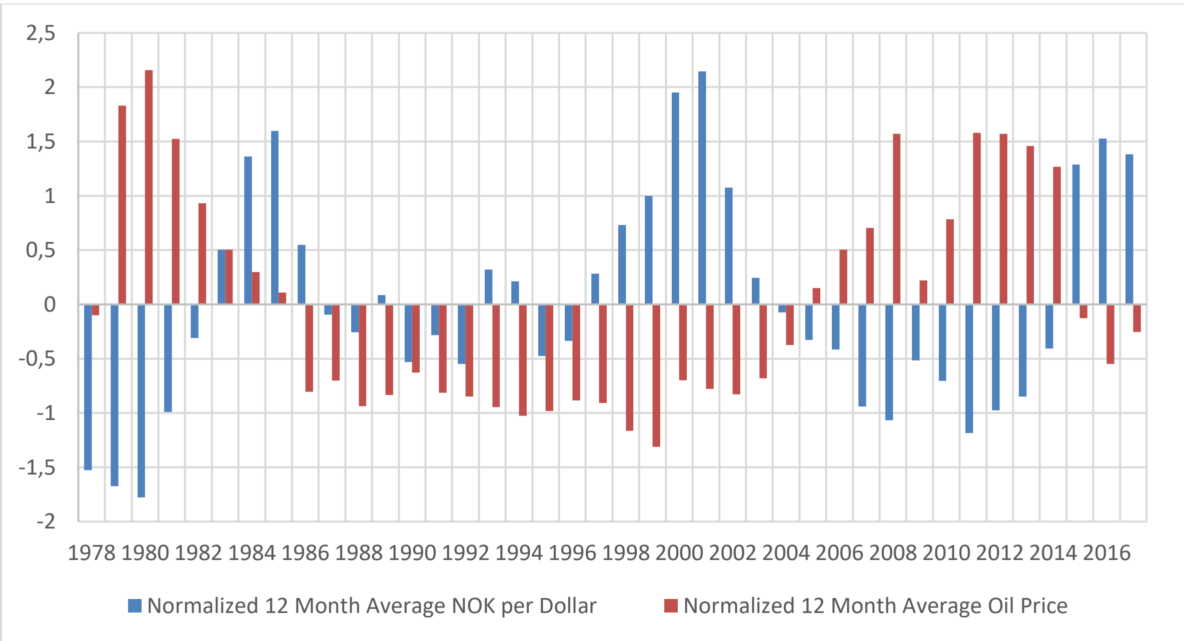

Figure 3-5 Correlation between Krone Value and Value of Oil.

3.1.1 How OPEC Acts in the Oil Market

In Figure 3-8 normalized values of oil price OPEC output, oil output from the NCS and oil prices from 2001 to 2017 is displayed, monthly datapoints have been used. In this figure OPEC output has been fitted with a positive linear trend. Oil price has not been attributed a trend, while Norwegian outputs, which has been on steady decline the last 18 years, has been fitted with a declining linear trend before normalizing. No certain conclusions can be drawn from this, but the Norwegian output has a smaller standard deviation, the Norwegian output has been more predictable, and has a weak negative correlation with oil price. OPEC output has quite large deviations from trend and a positive correlation with oil price, except in 2014 and onwards.

The real numbers for oil output in both Norway and from OPEC is displayed in Figure 3-6 and Figure 3-7. The numbers are given in different values, OPEC output is given as the average production each month in million barrels per day.

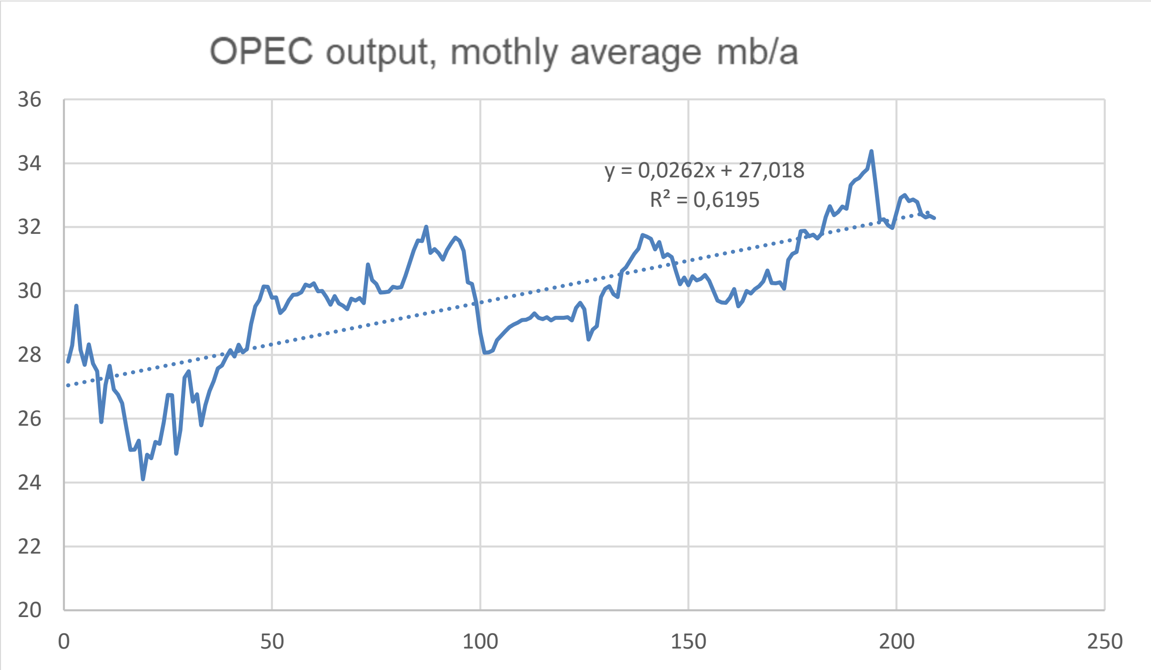

Figure 3-6 OPEC output (Reuters, 2018)

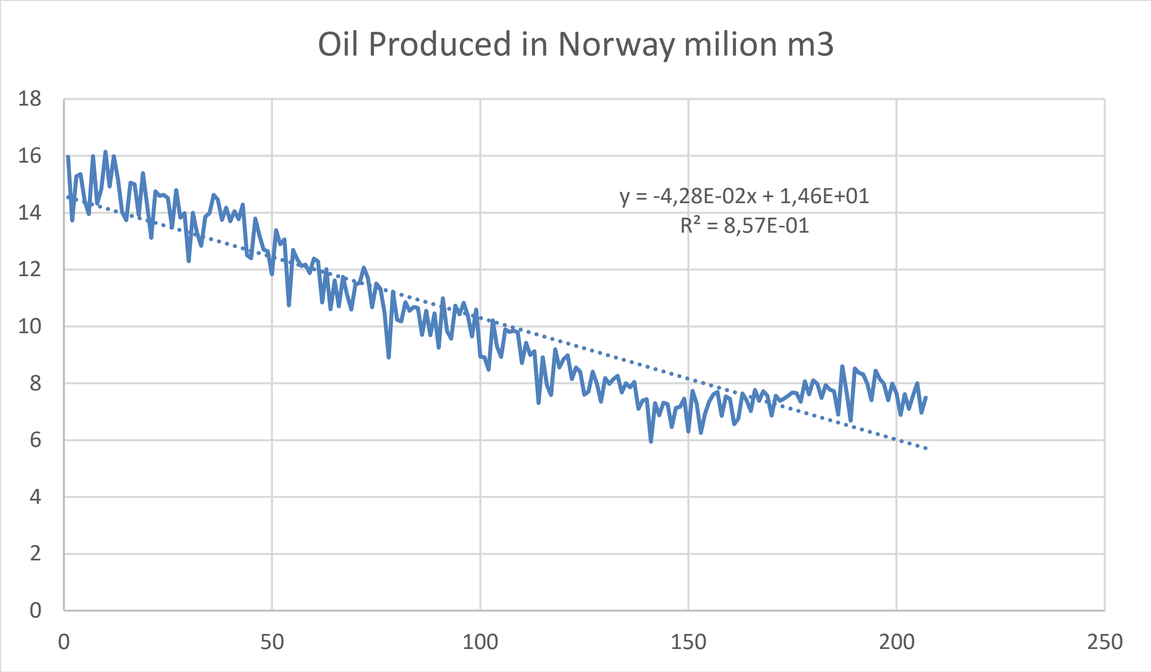

Figure 3-7 Norwegian output

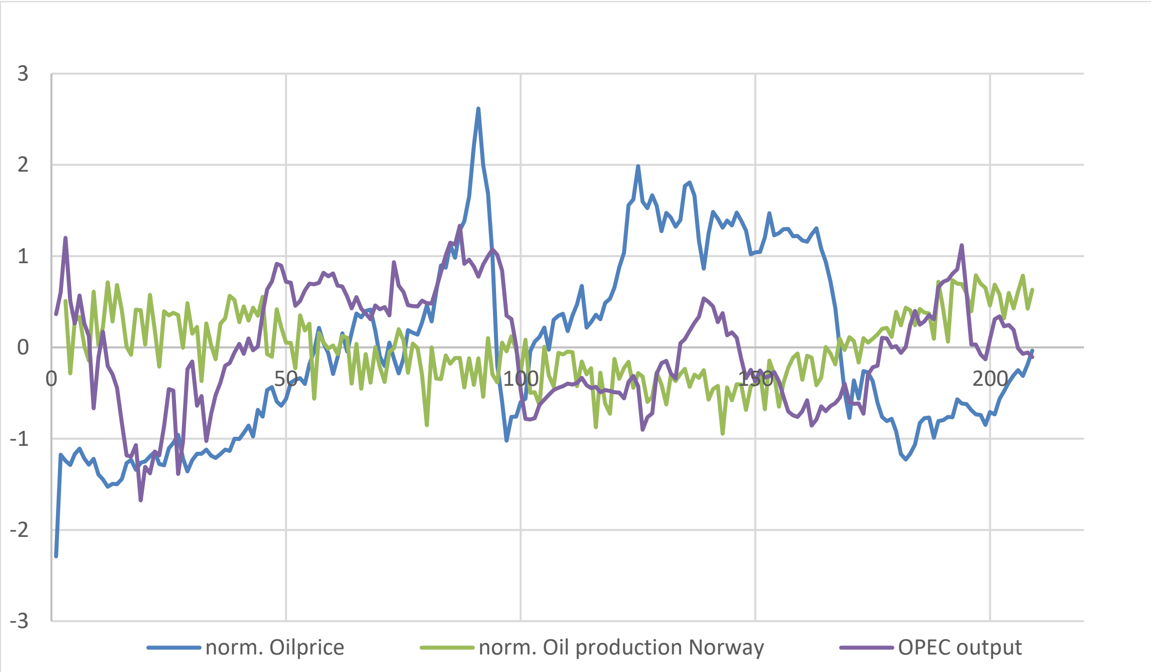

Figure 3-8 Normalized values of oil price, OPEC output and Norwegian output

The Norwegian output has a steady decline from 2004, but the decline tapers off in 2011. That means, in 2011 a new pronounced trend in Norwegian oil output occurs, and the linear trend used to normalize the oil output is distorted by this. This helps exaggerate the negative correlation between oil price and Norwegian output. It is hard to observe an adaption to oil price in the Norwegian oil-output, partly due to the small wiggle room in the Norwegian production.

The OPEC-production has a more pronounced deviation from its trend, this is partly due to the fact that OPEC output is aggregated numbers from several nations that can have individual disruptions in their oil industries. The standard deviation in monthly average of OPEC output is 2 million barrels daily production.

A correlation of 0,34 between oil price and OPEC output indicates that OPEC does to some degree adapt their oil output.

The surge in US shale production is something that might worry OPEC as US oil production are at an all-time high, with almost 10Mb/d (Lee, 2018). From Figure 3-8 it appears that OPEC increased its production output after the sharp fall in price in 2014, this is counter to the notion that OPEC seeks to maintain the oil price at a stable level and it might even imply that OPEC was trying to strangle expensive US shale production by dumping oil on the market.

3.2 Aggregated Numbers from the Petroleum Industry

Figure 3-9 shows the share each part of the petroleum industry has received of the total amount of money invested on the petroleum industry on the continental shelf between 1971 and 2017. The numbers used to derive this figure was given in nominal values. In Figure 3-9, Figure 3-10 and Figure 3-11 the investments in the industry is divided between six sectors, Exploration, Field Development, Producing Fields, Offices and Terminals, Decommissioning and Pipelines.

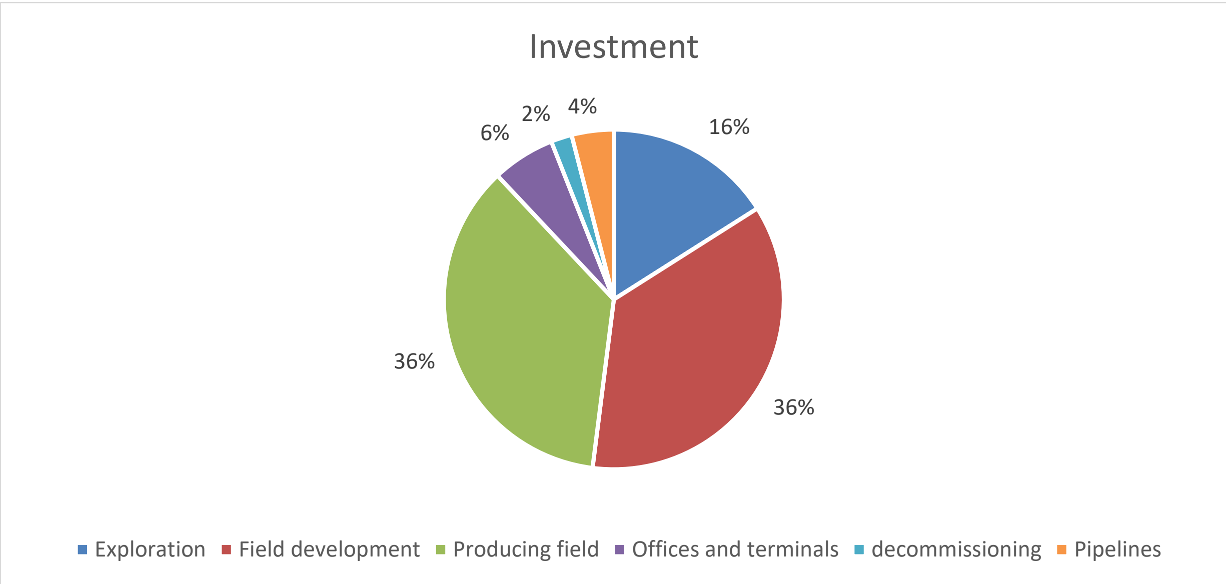

Figure 3-9 Total percentage share of invested money used by different parts of the petroleum industry (Søybe, 2017)

As shown in Figure 3-9, development of new fields and upgrades or maintenance of old fields has received equal share of the total amount invested on the continental shelf.

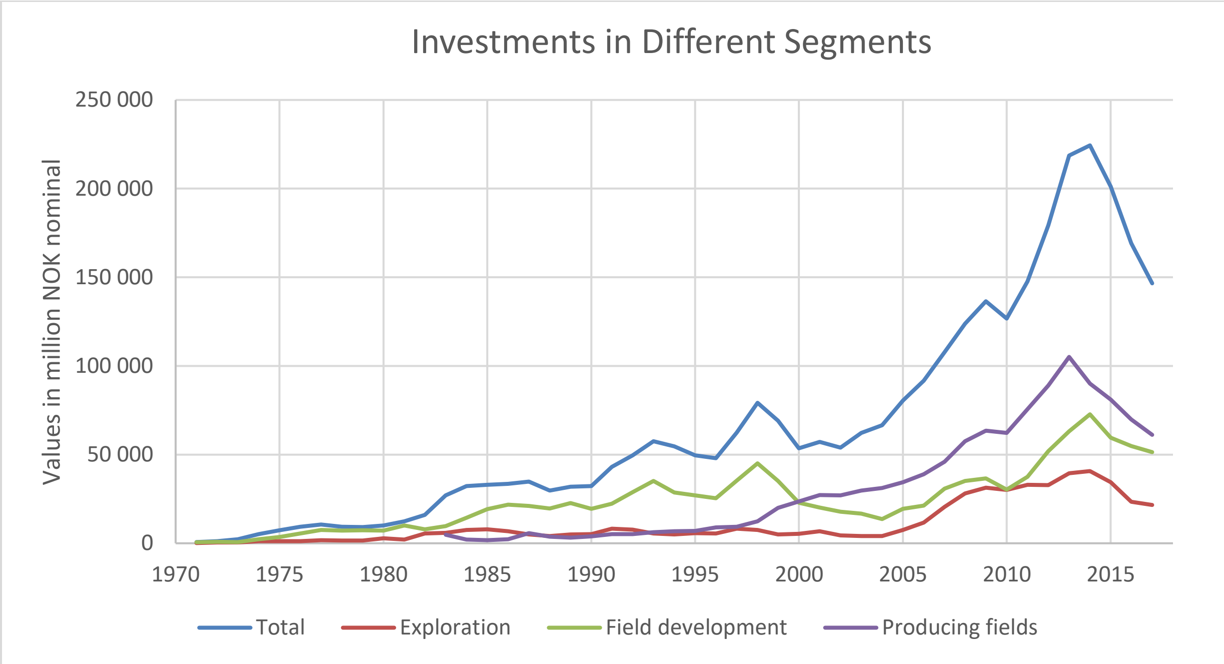

Figure 3-10 Investment in the petroleum industry (Søybe, 2017)

Numbers in Figure 3-11 has been derived from numbers in Figure 3-10.

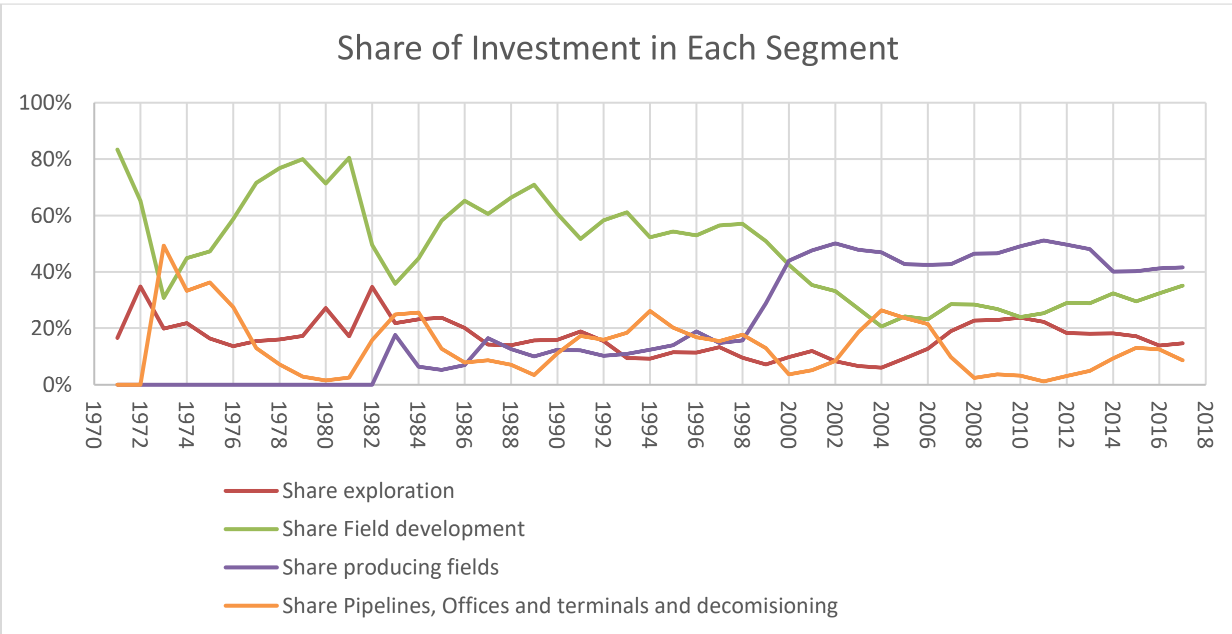

Figure 3-11 Share of total investment in the main segments.

In Figure 3-11 the share each of the segments in the industry receives of the total investment. Pipelines offices, terminal and decommissioning has been aggregated into one segment. This graph can provide some useful information on the trends in the industry. The early part of the charts is affected by the fact that there were few, but large development projects on the continental shelf, this is displayed in Figure 3-22 and Figure 3-24 in chapter 3.2.1Field Development. This seems to have created an alternation between field development, exploration and development of infrastructure, such as pipelines and terminals. This sequential approach to project development is described in Chapter 2.1.2.

A major shift in how investments has been distributed happened between 1998-2004. The share of investment to developing new fields dropped from almost 60 percent 1998 to ca 20 percent in 2004. While investment share in producing fields increased from 18 percent to 50 percent. The absolute values can be read in Figure 3-10. Part of the reason for the relatively sudden change in from 1998 was the drop-in investments due to the oil price bust. The fields that was already developed represents investments with a lower risk, while the development of new fields entails many uncertainties and could easily be postponed. Also, the number and age of the developed fields had been rising, thus demanding an ever-larger investment in already developed fields.

Similar dramatic shift in investments cannot be observed after the oil bust in 1985.

The fall in investments in 2014 did affect investments in producing fields more than development of new fields. Investment in producing fields fell by 50% from 2014 until 2017. While development only fell by 17% in the same period, the numbers are illustrated in Figure 3-12. Assuming there is a larger time delay before the Field Development category reacts to structural changes in the petroleum industry, the fall in investments can be calculated from 2015. In this case the field development category fell by 32 percent and the Producing Fields category fell by 36 percent.

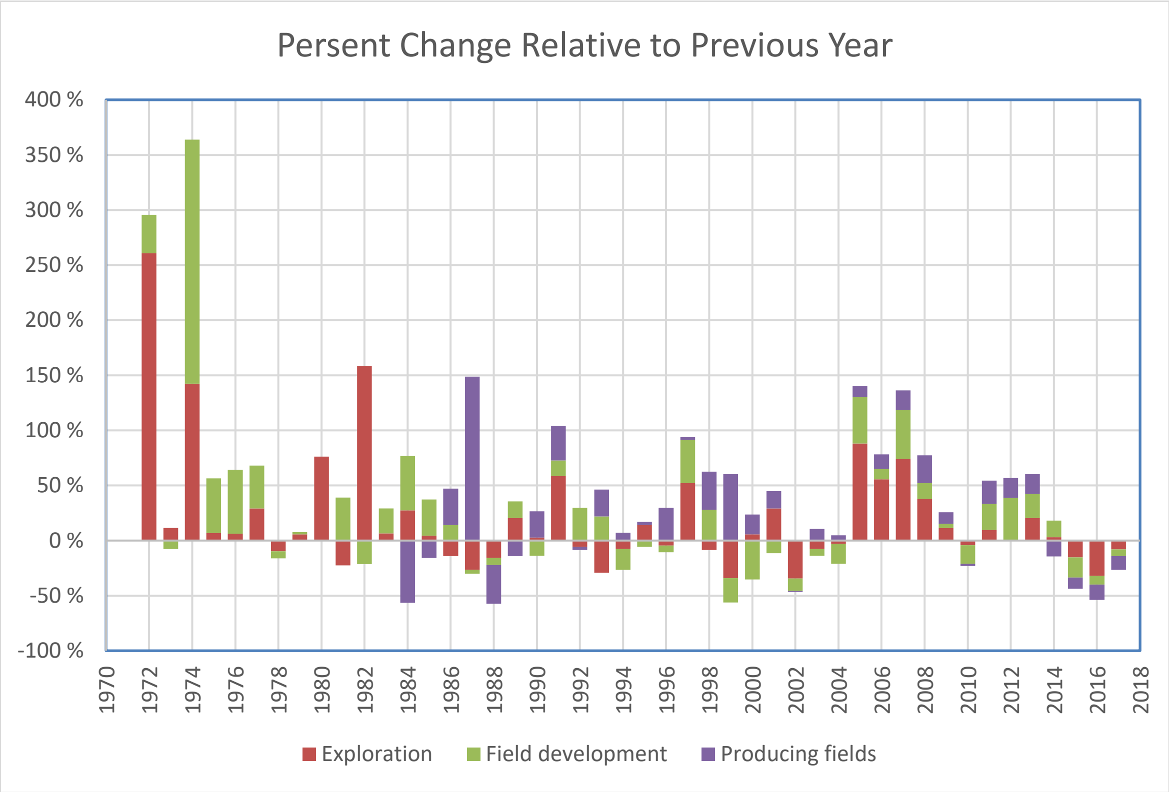

Figure 3-12 Percent Change relative to Previous Year Investment, by segment.

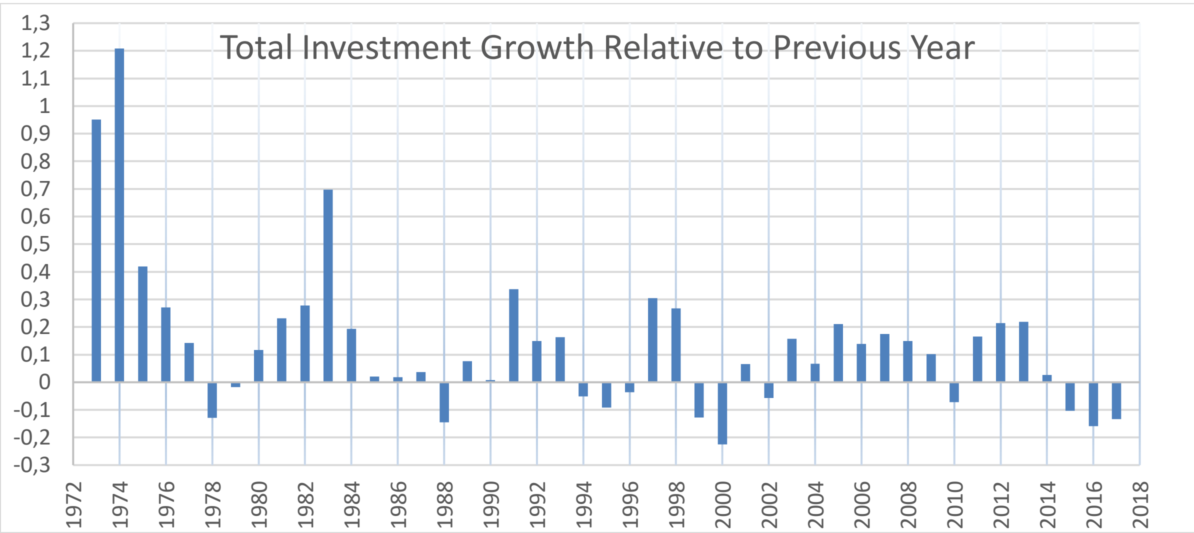

Figure 3-13 Annual Growth in Investment

Figure 3-13 shows the annual growth in investment. The only previous period of three consecutive years of negative growth in oil investments was 1995-1997, in this period total investments shrank by 17% compared to 1994. In the end of 2017 total investments had shrunk by almost 35% compared to 2014. In 1999 and 2000 the investment shrank by 32%. Total amount invested is displayed in Figure 3-10. This makes the 2014 drop in investments to the oil industry the most dramatic as of 2018.

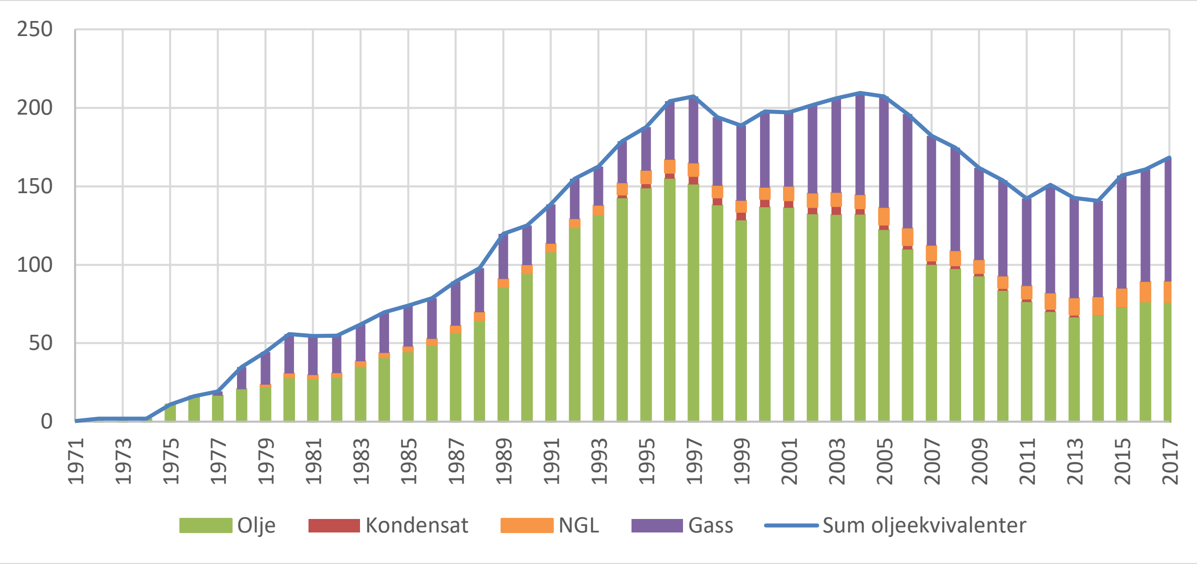

Figure 3-14 Volume of Petroleum Produced (Norwegian Petroleum, 2018b).

The number of people employed in the petroleum can be an indicator of the activities in the sector. there are different ways of defining whom is employed in for example a related industry, but the numbers from SSB's annual national account can be used. The numbers displayed in Figure 3-15 represent employment in companies that are fully geared towards the petroleum sector. From this figure it is obvious that the first real drop in employment occurred after 2014. Previous there has been a streak of a shrinking in the oil and gas workforce between 1993 to 1997. The total workforce has only decreased, in relation to previous year total employment, in 1986, 1994, 1998, 1999 and 2002. In 2013 the employment increased by only 1,5% from 2012 and between 2014 and 2017 the workforce has been decreasing from ca. 65700 employees to ca 50700.

Figure 3-14 displays the volume of Oil equivalents produced on the NCS each year. The volume of oil has been declining from the top production year 1995 in terms of volume. Gas had a period of declining production volume between 2006 and 2011 from 73 to 56 Sm3 oil equivalents. Also 2012-2014 there was a decrease from 69 to 62 Sm3 oil equivalents. Other than that, the volume of gas has been increasing. On interesting aspect that is displayed in Figure 3-14, Figure 3-10 and Figure 3-15 is that while employment and investments in petroleum declined when oil price fell, the production volume increased

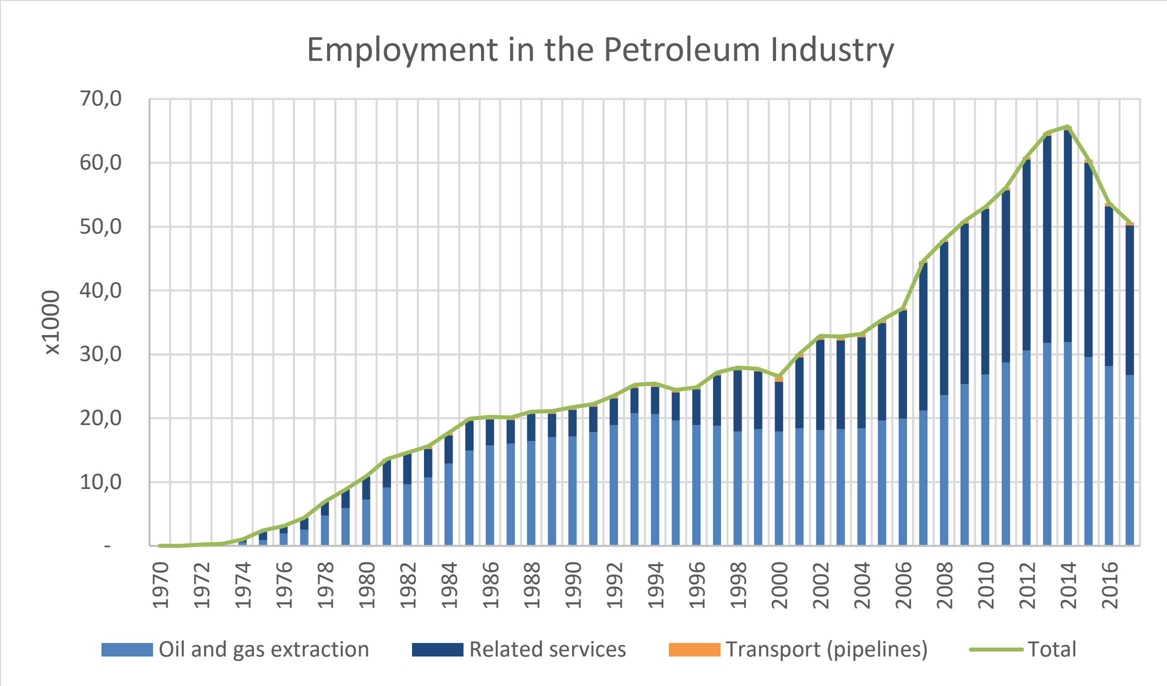

Figure 3-15 Number of employees in the petroleum industry (Norwegian Petroleum, 2018a)

The total number of employed people in the industry has been increasing every year from 1972, except from year 2000 and 2014-2017. The number of people employed directly involved in oil and gas extraction increased from 1972 until 1993, after 1993 this number remained stable until ca. 2007 when this number started to increase. This could be linked to the increase in number of companies from 2007, shown in Figure 3-21. The number of active fields, displayed in Figure 3-23, would imply that the number of people employed in oil and gas extraction would increase.

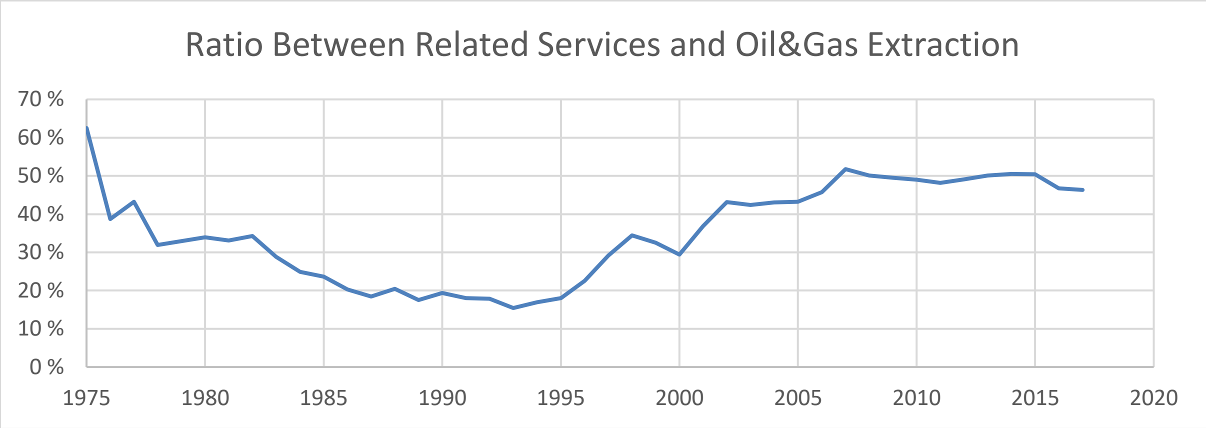

Figure 3-16 Ratio Between Employment in Related Services and Oil&Gas Extraction.

From 1985 to 1995 only between 25 and 15 percent of the total number of employed people in the oil and gas industry was working in Related Services. Between 1995 and 2007 this increased to 50 percent, and after 2007 this ratio kept steady.

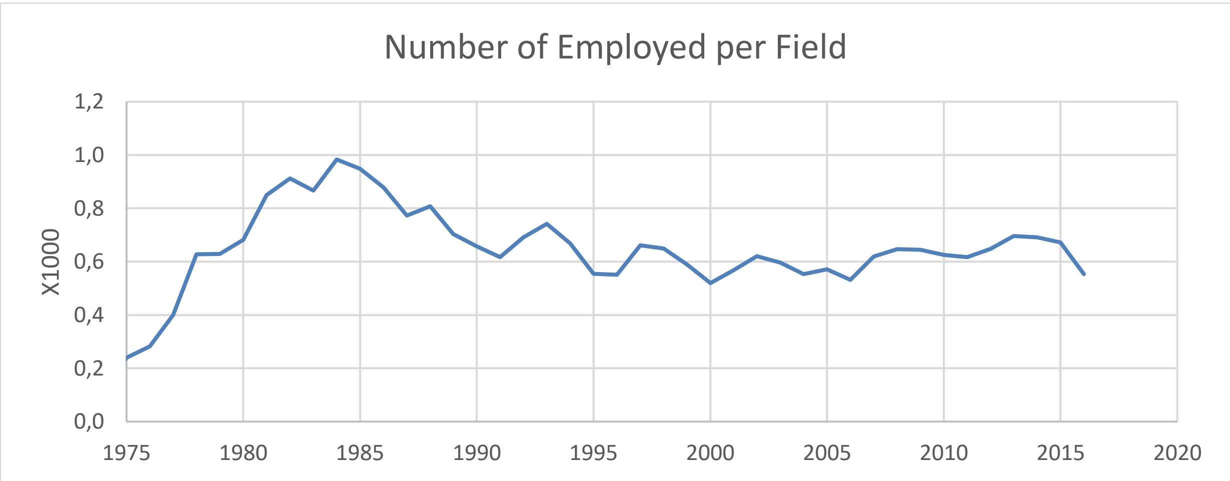

Figure 3-17 Average Number of People Employed per Field

As can be seen from Figure 3-17 the average number of people employed in the industry has been on a declining trend. Accounting for the ratio displayed in Figure 3-16, the reduction in people directly employed in oil and gas extraction has significantly declined since 1985.

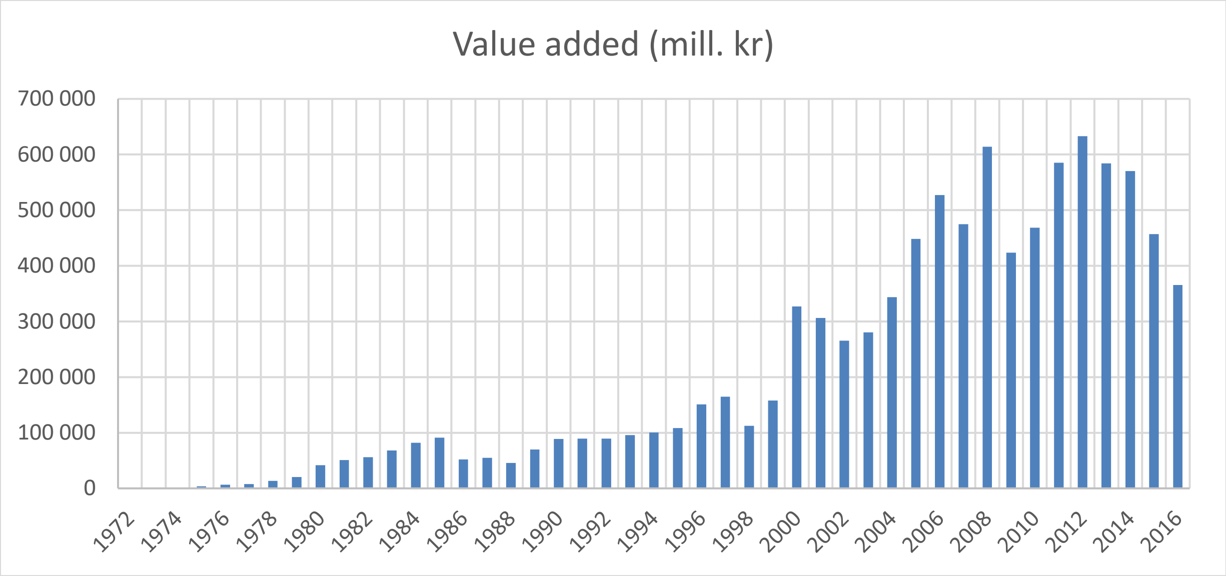

Figure 3-18 Value added from petroleum production (Skullerud, 2017).

The Value-added numbers that is displayed in Figure 3-20 Government cashflow, taxes, fees and dividends (Norsk Petroleum, 2018). Figure 3-20 and Figure 3-18 refers to the production value from the petroleum production subtracted the cost of commodities and services that was used in the process (SSB, 2018b). The numbers in this figure is not adjusted for inflation. This indicator reveals the value the production companies are adding to the petroleum in the ground.

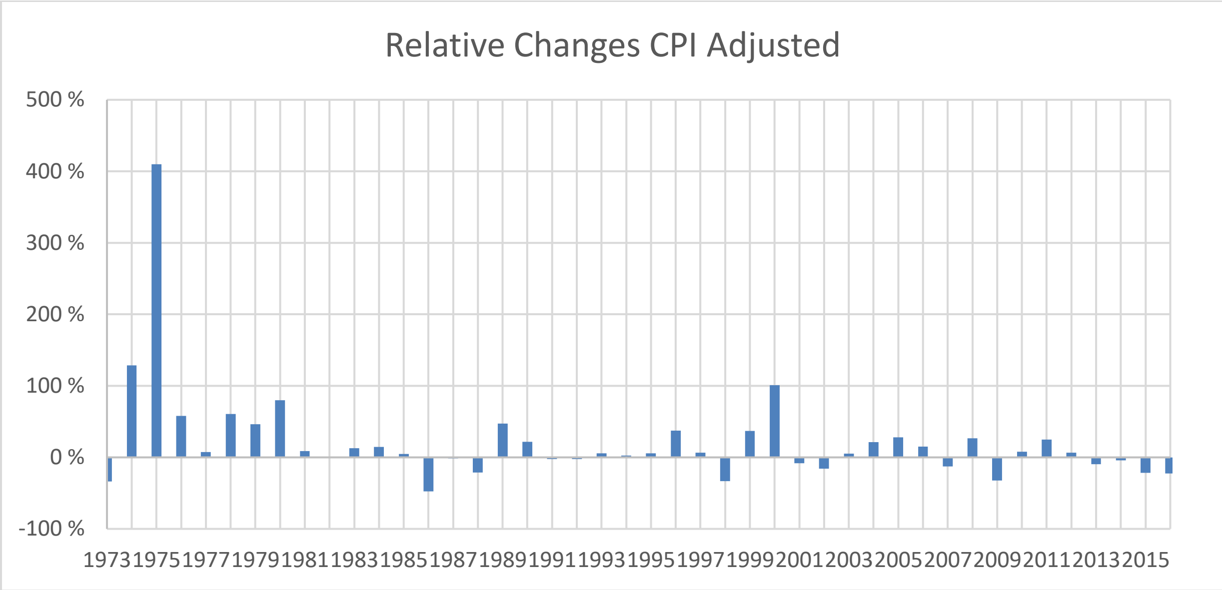

Figure 3-19 Changes in Investment Relative to Previous Year (Numbers Deflated to 2018 Value)

Figure 3-19shows the relative changes to the value added from petroleum production. The numbers in this figure is deflated with the Norwegian Consumer Price index so that the real value added is revealed.

The only period with 4 consecutive years of declining value added is the period between 2013 and 2016. The numbers from 2017 has not been published yet. 1986 the value added fell by 47 percent, and over the period -86 to -88 the value had fallen by 70 percent. In 1998 the value fell by 33 percent. From 2013 to 2016 the value added fell by 58 percent. The fall in Value added has a large effect on taxes, as the production company's deficits can be carried forward indefinitely.

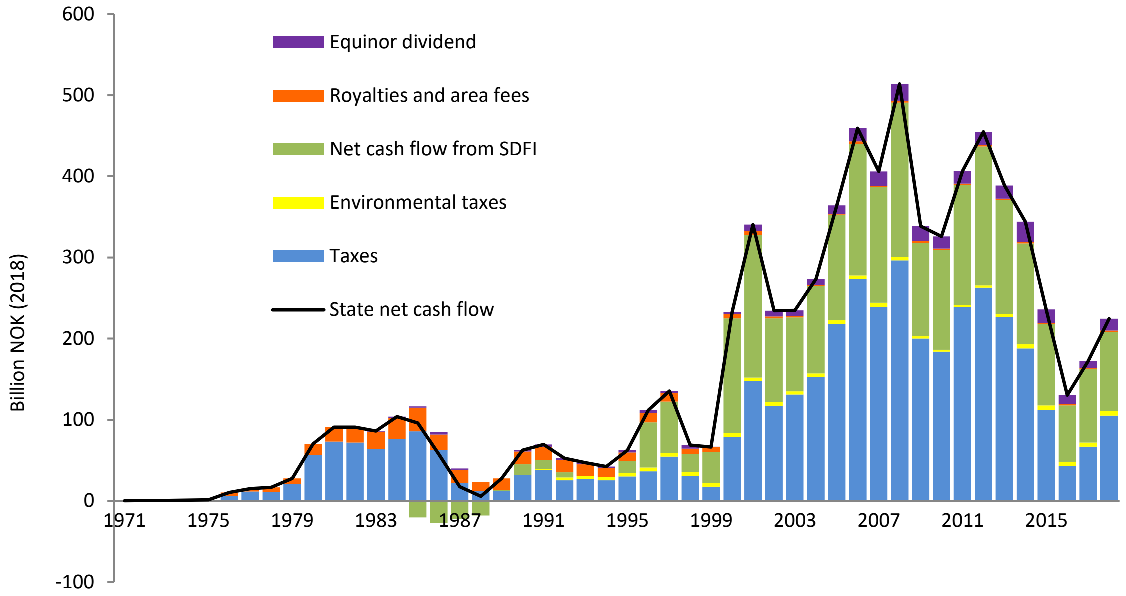

Figure 3-20 Government cashflow, taxes, fees and dividends (Norsk Petroleum, 2018).

Figure 3-20 display the net cash flow from the petroleum industry to the government.

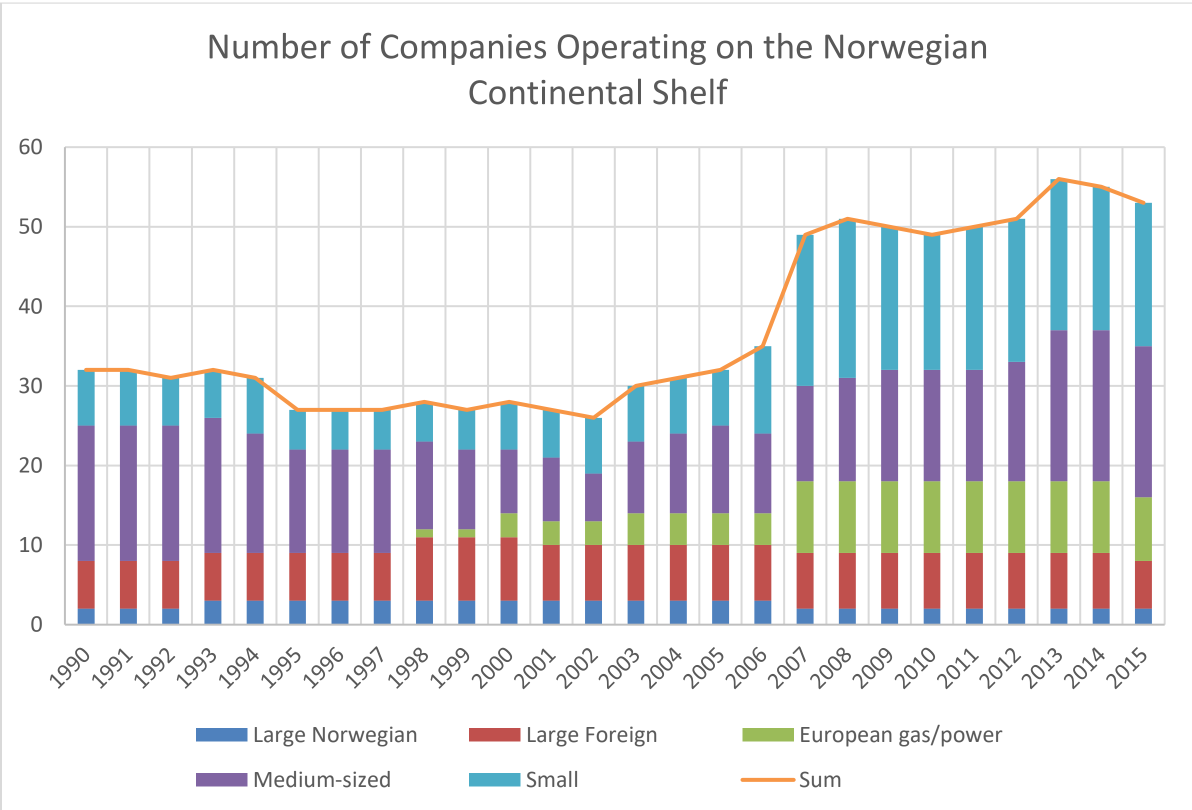

Figure 3-21 Numbers of Companies Operating on the NCS, segmented after size and origin (Norwegian Petroelum Directorate, 2017).

The number of companies operating on the continental shelf is displayed in Figure 3-21. Accurate numbers ranging back to the 1980s was hard obtain but would have provided an interesting perspective. The companies in the figure has been divided into 5 Segments; Large Norwegian, Large Foreign, European Gas/Power, Medium-sized and Small. What companies goes in what category is listed below:

- Large Norwegian: Statoil, Petoro, Norsk Hydro
- Large Foreign: Total, Eni, ConocoPhillips, ExxonMobil, Shell, Chevron
- Medium-sized: Lundin, Wintershall, Repsol, AkerBP, Hess, Idemitsu, Maersk, Tullow, Suncor, OMV, Lotos, Capricorn, DEA, MOL, Lukoil, Rosneft
- Small: Faroe, Fortis, Concedo, Skagen44, Lime, Origo, Kufpec, Atlantic, Wellesley, CapeOmega, North E&P, Point Resources, OKEA, Petrolia, Production Energy Company
- European Gas/Power: Centrica, Engie, Dong, Bayerngas, PGNIG, VNG, Edison

The company share market value has been used to determine what companies are small or large.

The Large Norwegian category has remained stable between 2 and 3, a merger happened in 2007 with Statoil and hydro. Number of large foreign companies has also remained stable throughout the period accounted for in Figure 3-21. The number of medium sized and small companies has changed, and the number of European gas/power companies have increased. This is supports the notion of a consolidation wave that hit the industry ca 1998. Medium sized companies shrank from 17 in its hight in 1993 to 6 in 2002. After 2002 the medium sized companies grew to 19 companies in 2013. The Small companies category remained at 5-7 companies until 2006. This category increased from 7 in 2005 to 19 in 2013. European gas/power companies increased from 1 in 1998 to 9 in 2013.

3.2.1 Field Development

There are 3 distinct time horizons in the oil marked; short-term, medium-sight and long-run. *Short-term* lasts for days, weeks, months or a year. In this time perspective, it is smaller events and the believes of the actors in the market that moves the price; such as weather, movements in exchange rates, storage numbers and so on.

On a *medium-sight*, about 2-10 years, it is more fundamental demand and supply factors that play the important role. For example, when China became part of the world economy in 2003, it caused a permanent higher demand for oil which caused a boom in oil price, whereas the surge in shale oil from 2008 caused a higher supply, and thus an unbalance in the market which caused a bust in oil price.

Long-run in oil prices can be regarded to be between 10 and 30 years. It is an ongoing debate whether the oil price is on a declining long-run trend due new discoveries or because of increasing competition from substitutional energy sources, or if the price follows an increasing trend, due to the limited amount of existing oil and the increasing difficulties to produce it. (Austvik, 2016)

On the Norwegian continental shelf, there is not uncommon to have time lag of 5-10 years from a reservoir is discovered until it is developed or included in a producing field. The average time between a field is approved for production and its status is changed to producing is 2,9 years, standard deviation 1,6 years, according to numbers from on NPD's Fact Pages (Norwegian Petroleum Directorate, 2018).

As stated earlier in chapter 0, the government plays an important role in field development, as it must approve the plans for the field. What goal the government has for the industry is an interesting question with many implications, it is not given that government should, or wishes to, act as a rational consumer or a rational producer. That is, the government does not necessarily only aim to increase its profit from taxes in the long or short run, nor does it necessarily aim to maximize utility in terms of obtaining something of highest possible value at the lowest possible price. The goal for government might be something in line of increasing or maintaining the socioeconomic benefits of the industry.

Given the cost overruns described in chapter 2.4.2, one could assume that the government would be most inclined to limit activities when the industry is overheating, as the high activities means that recourses must be imported. This was done in 2013, by decreasing the free income from 30% to 21,2% the government made it slightly less profitable to develop new fields, it is possible that this contributed to the downturn in the industry.

At the same time, the goal of an oil company does not necessarily align with what is the best socioeconomic outcome. Companies might be subject to; demand for fast payback on investments, capital limitations on investments and they might be willing to take a higher risk while developing projects. These limitations could be counterproductive to maximizing socioeconomic utility of resources in the long run.

For example, flaring of gas is cheap and looks like the most economical solution when accounting for the large, long term investments that must be made to not flare the gas. Constraints from the government forced the oil companies to not flare it, this has most likely maximized resource utility in a socioeconomic perspective. The Norwegian Petroleum Directorate suggested that re-injections of gas has boosted oil recovery by 2 billion barrels in 2010 (Hinderaker & Njå, 2010).

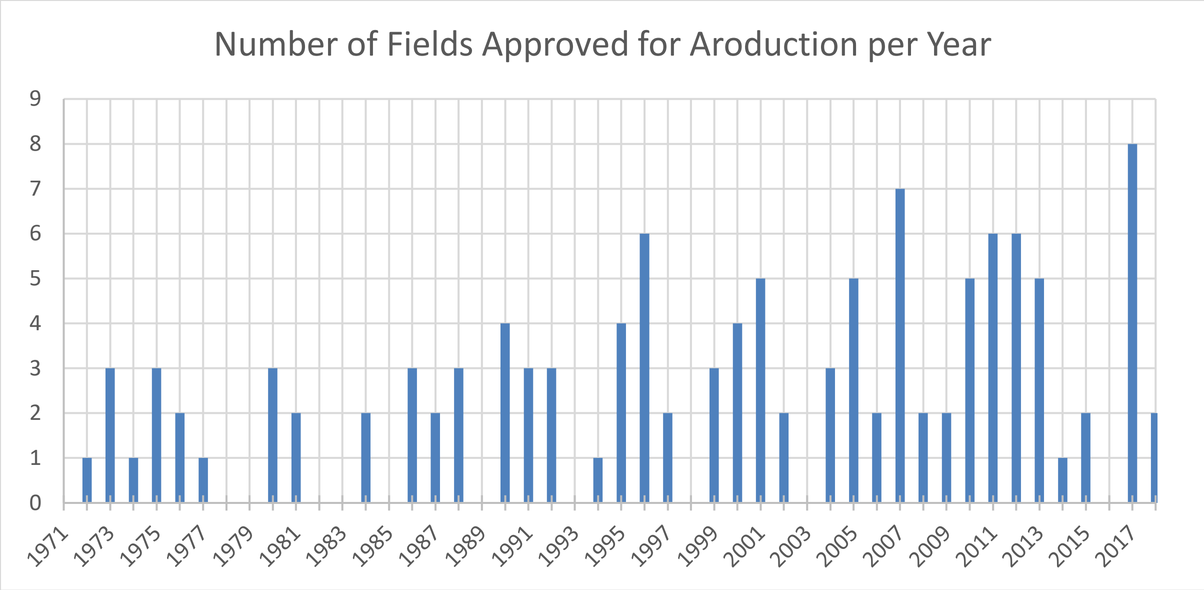

Figure 3-22 Number of fields approved for production per year (Norwegian Petroleum Directorate, 2018).

Figure 3-22 does not display the number of PUD's approved because a PUD can be for improvements or upgrades on existing fields, such a case would not be counted in this figure. This figure only contains numbers for development of new fields.

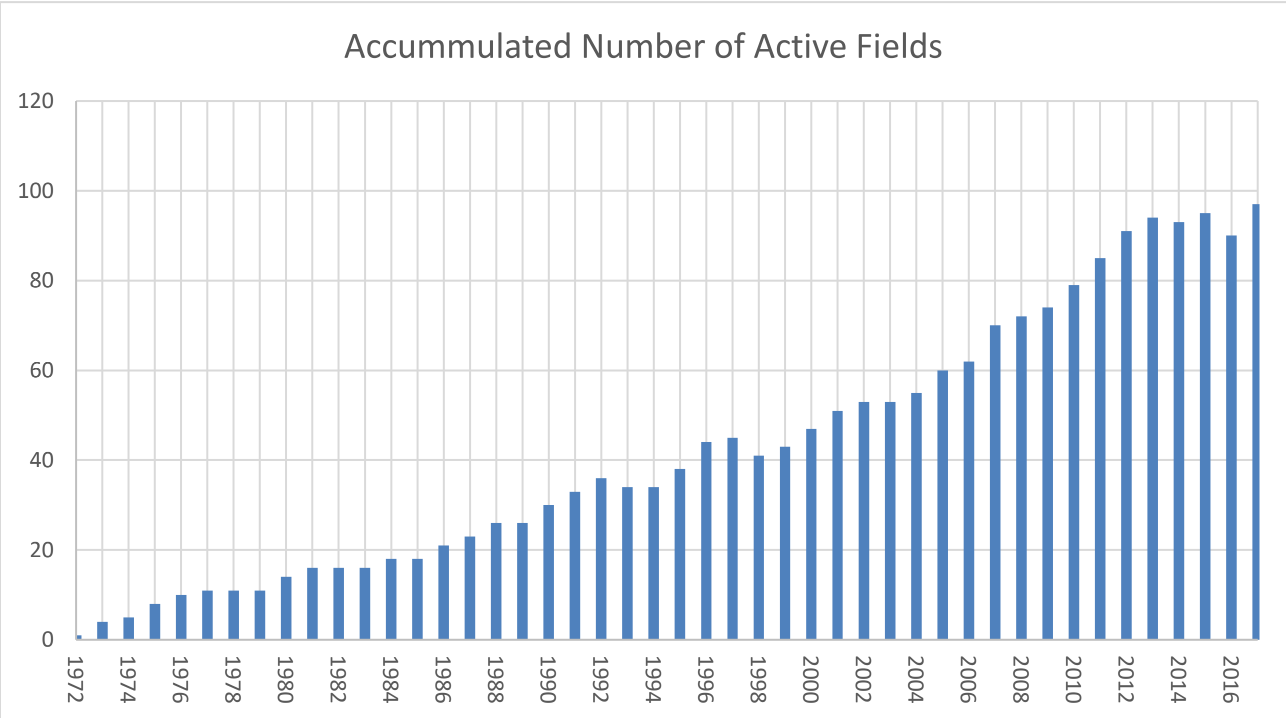

Figure 3-23 Accumulated Number of Active Fields (Norwegian Petroleum Directorate, 2018).

In Figure 3-23 the number of field that has been shut down has been accounted for. The average age for fields in production in 2017 was 19,1 years.

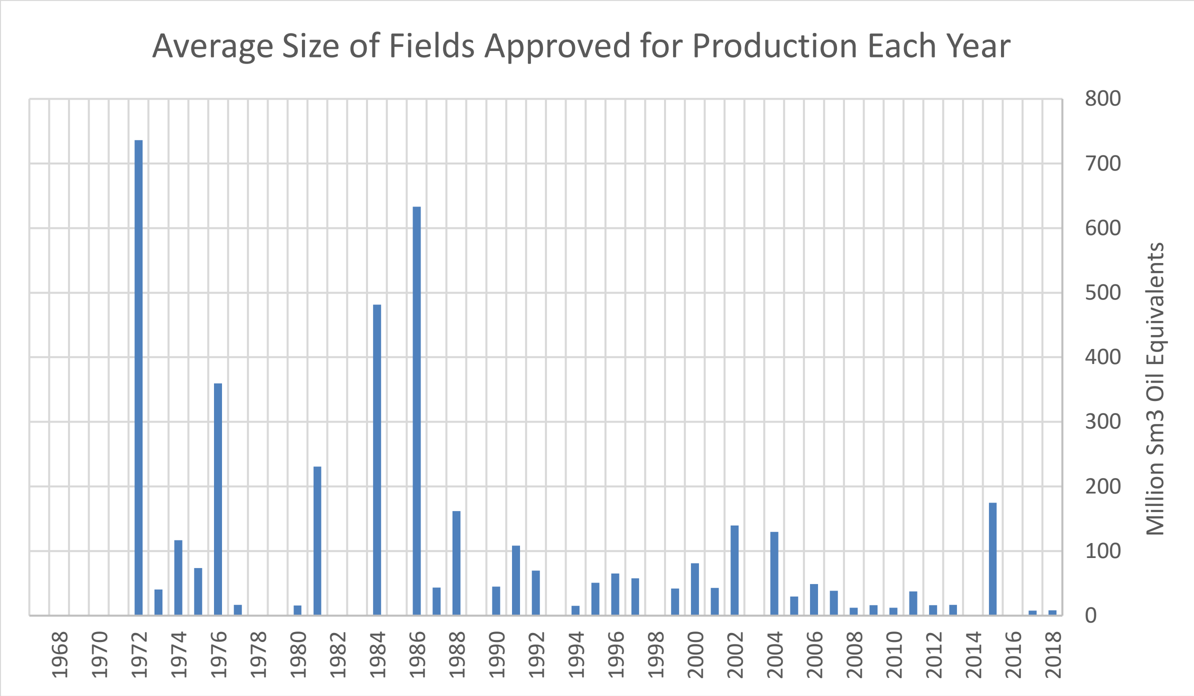

Figure 3-24 Average size of fields approved for production (Norwegian Petroleum Directorate, 2018)

It is no obvious connection between the number of fields approved for production each year and the oil price. The number of fields approved each year is displayed in Figure 3-22, but the average size of fields approved has been on decline. It does however seem to be a slight connection between the average size of fields approved shortly after a bust in oil prices. The average size of fields is displayed in Figure 3-24. This could imply that government is withholding valuable fields through strategic license distribution in order to counteract the large swings in the industry. On the same note, it could be argued that in high activity periods, the fields approved for production seems to be smaller. It was also stated in the annual press releases issued by the Norwegian petroleum directorate that was presented in chapter 2.1.1.

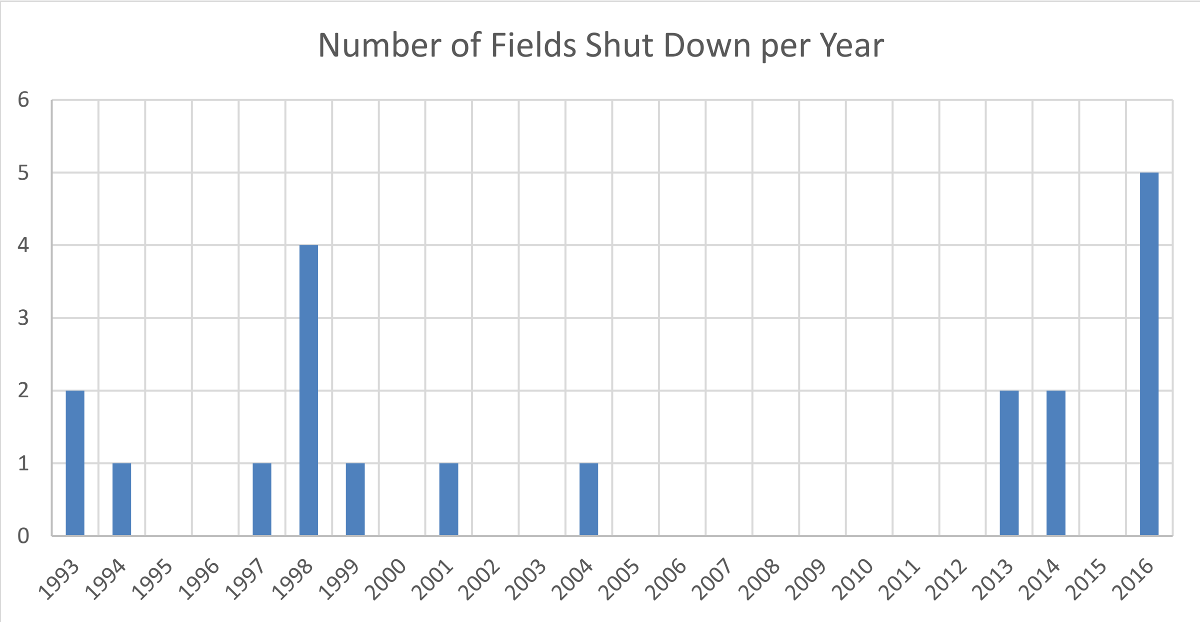

Figure 3-25 Fields Shut Down by Year (Norwegian Petroleum Directorate, 2018).

In Figure 3-25 the number of fields shut down on the shelf is displayed. The first fields where shut down in 1993. This figure indicates that more fields are shut down in periods of low prices. Fields that are close exhausted is more likely to be shut down when falling prices increases the barrier for what volume must be produced to maintain a profitable activity on the field.

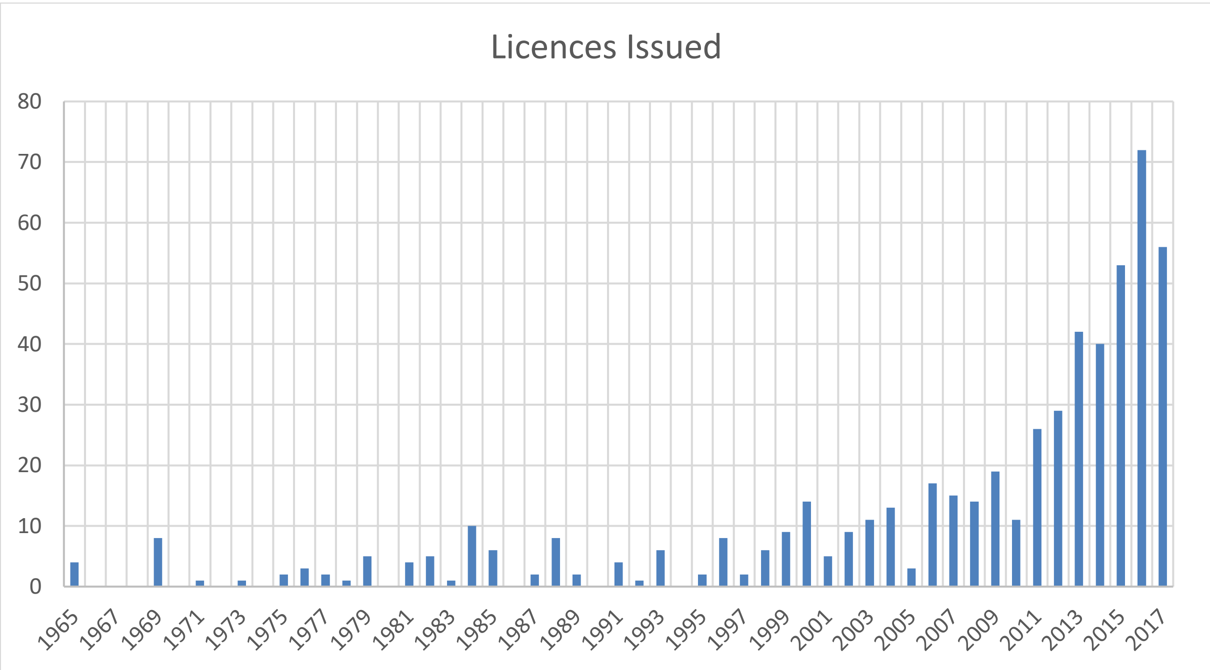

Figure 3-26 Number of licenses Issued per Year (Norwegian Petroleum Directorate, 2018).

The number of new license have increased dramatically from 2001 to 2017. There can be several reasons for this; the government wishes to encourage to exploration, there are few valuable licenses left[28] or, due to more companies operating on the shelf, along with more infrastructure there is a higher capacity to utilize a larger volume of licenses. Most likely, it is a combination of these factors.

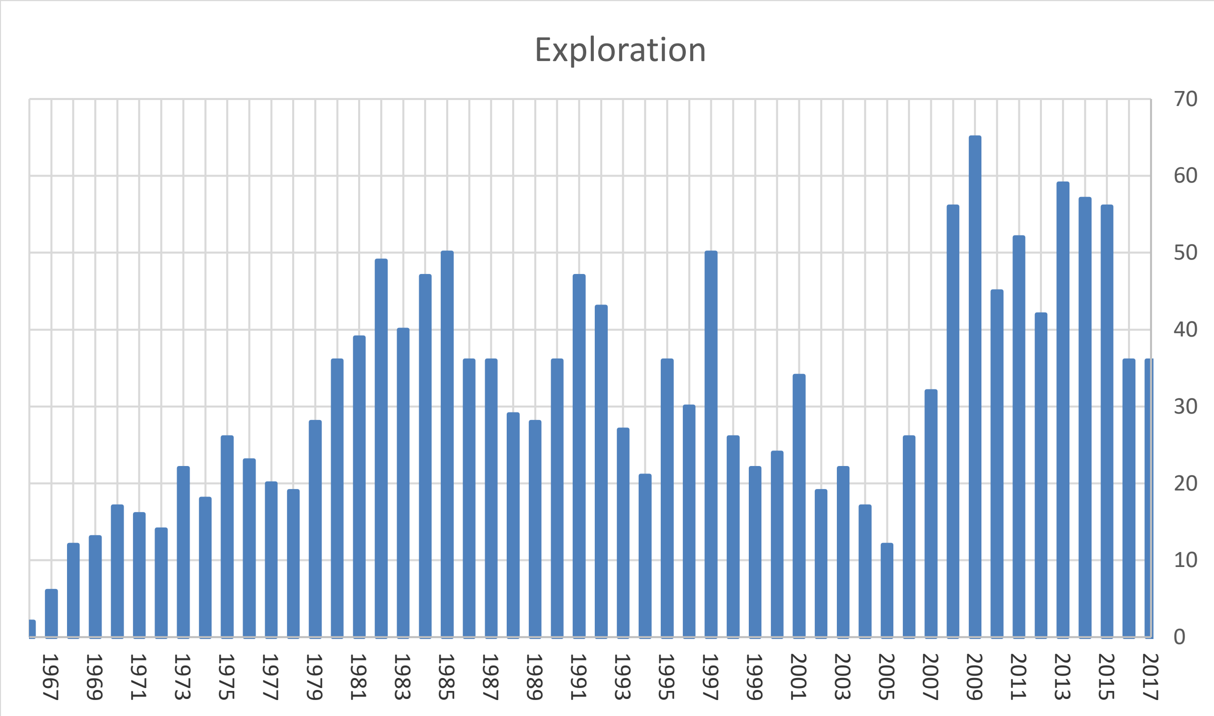

Figure 3-27 Exploration wells Finished Each Year (Norwegian Petroleum Directorate, 2018).

In 2005, the government issued an incentive for more exploration drilling. This seems to have worked. The 78% of the cost from exploration drilling would be covered by the government if the company does not have enough income to cover it as deductible, in effect this could be seen as a rent-free loan. From Figure 3-27 it appears that exploration drilling had a large upswing after 2005. This makes it hard interpret any long-term trends, as the dataset has a skew because of incentives introduced. There seems to be a significant drop in wells drilled soon after a significant reduction in the oil price. The main effect of reduction in drilling activity can be seen in the reduction of cost regarding drilling.

[28] This is implied by the decline in volume of oil Equivalents in producing fields, shown in Figure 3-28

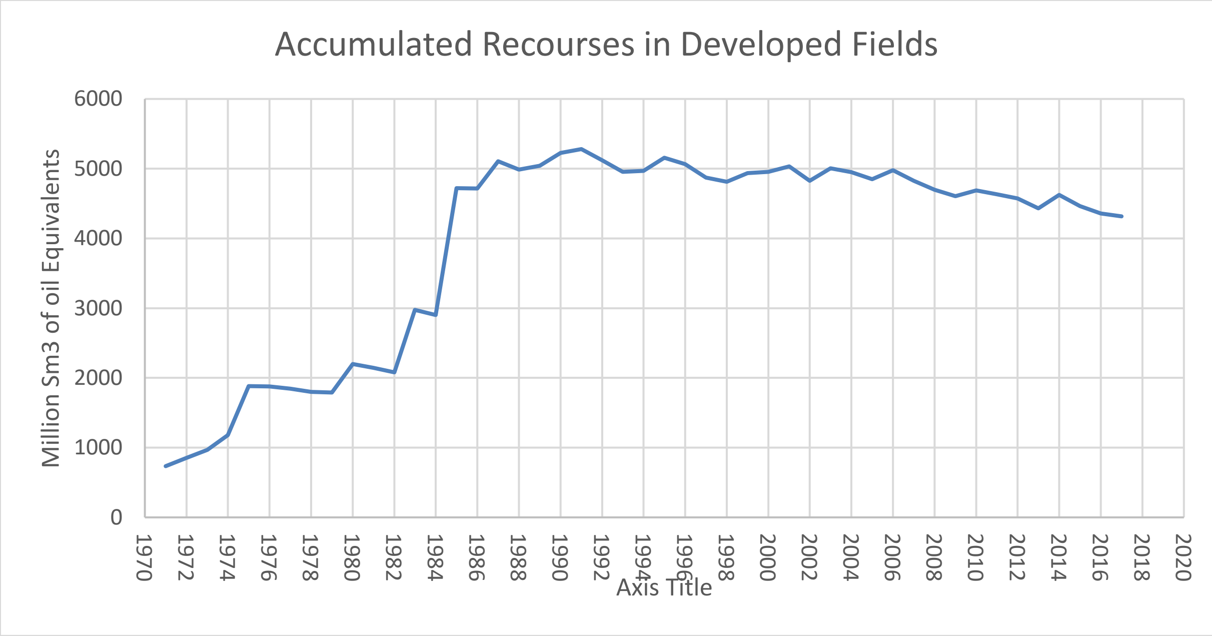

Figure 3-28 Accumulated Million Sm3 of oil equivalents, in a field that is being produced

In Figure 3-29 the accumulated volume of oil equivalents in a producing field is displayed. There has been a steady decline in the volume of oil equivalents in active fields, this implies that exploration cannot keep pace with production on the continental shelf. From 2006 to 2017 the volume in fields declined from ca 5000 million Sm3 to 4300 million Sm3. A 14% reduction in available volume.

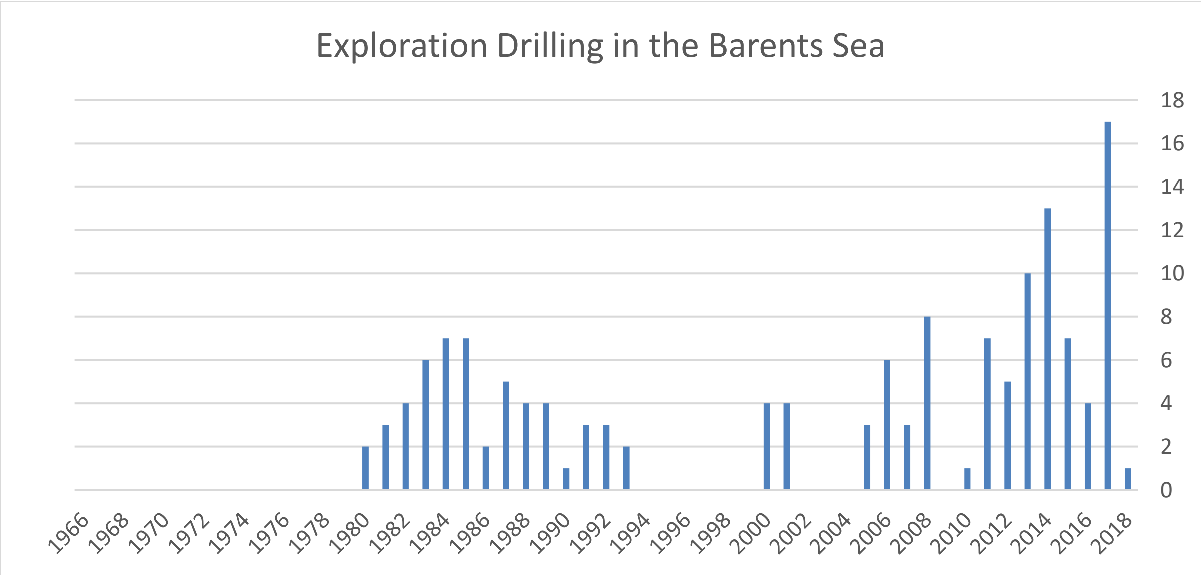

Figure 3-29 Exploration wells in the Barents Sea (Norwegian Petroleum Directorate, 2018).

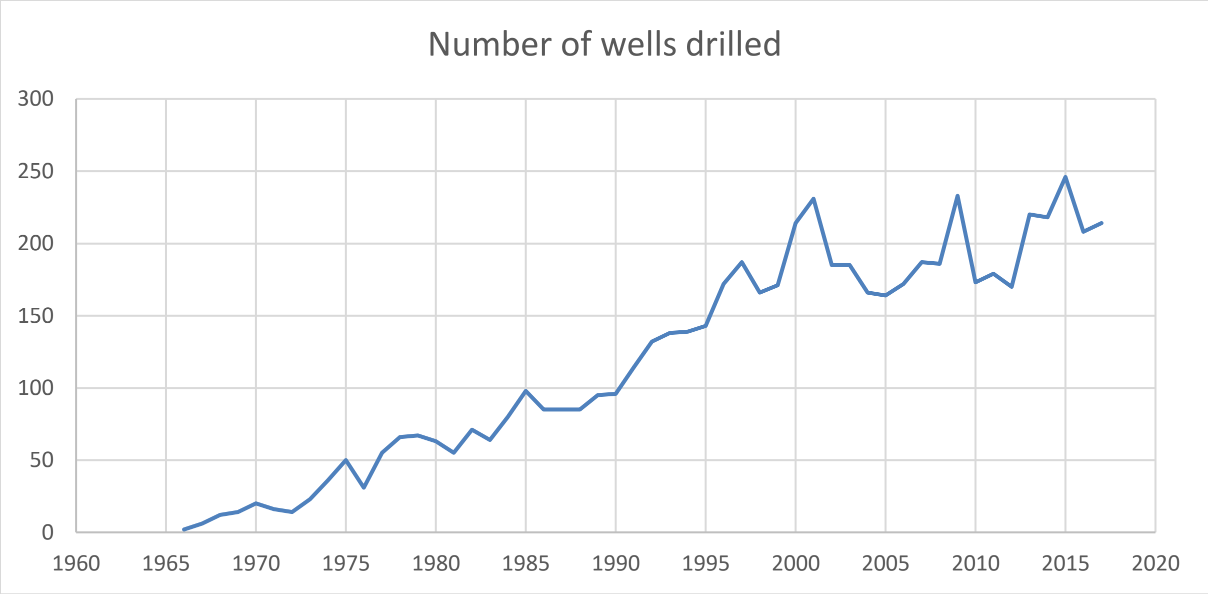

Figure 3-30 Numbers of wells drilled on the NCS (Norwegian Petroleum Directorate, 2018).

The number of exploration wells drilled in the Barents Sea increase after the introduction of incentives for exploration drilling, this is displayed in Figure 3-29. In Figure 3-30 it appears that number of wells drilled each year stop increasing after 2001.

3.2.2 The Service and supply industry

The index displayed in Figure 3-31 is made of numbers from building of ships, oil platforms and modules, and recreational boats. Although the index is composed of many sources, the most important contributor is the numbers from the oil industry. The figure illustrates how the 2014 fall in oil prices affected the manufacturing industry.

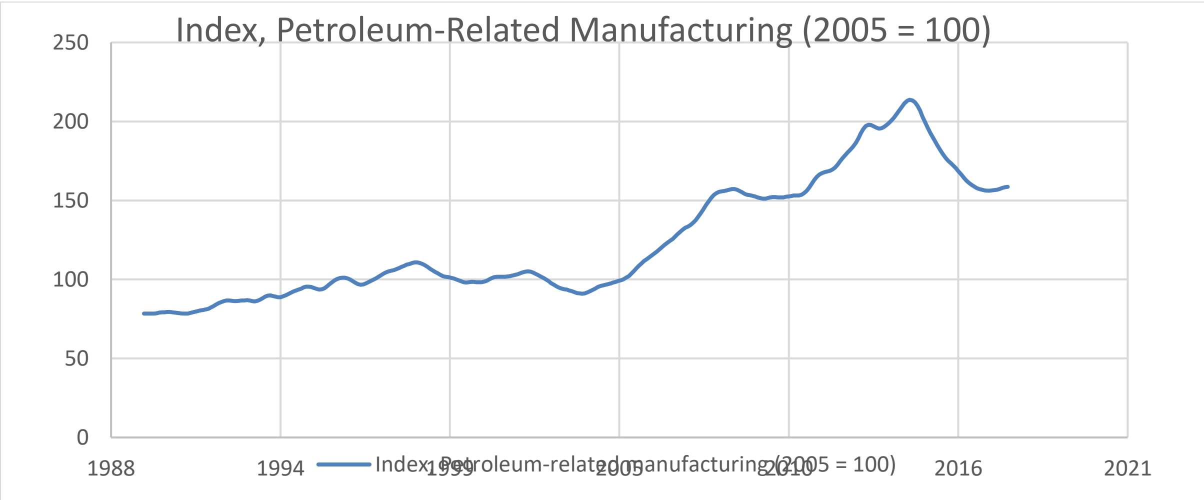

Figure 3-31 Index, Petroleum related manufacturing (Statistics Norway, 2018).

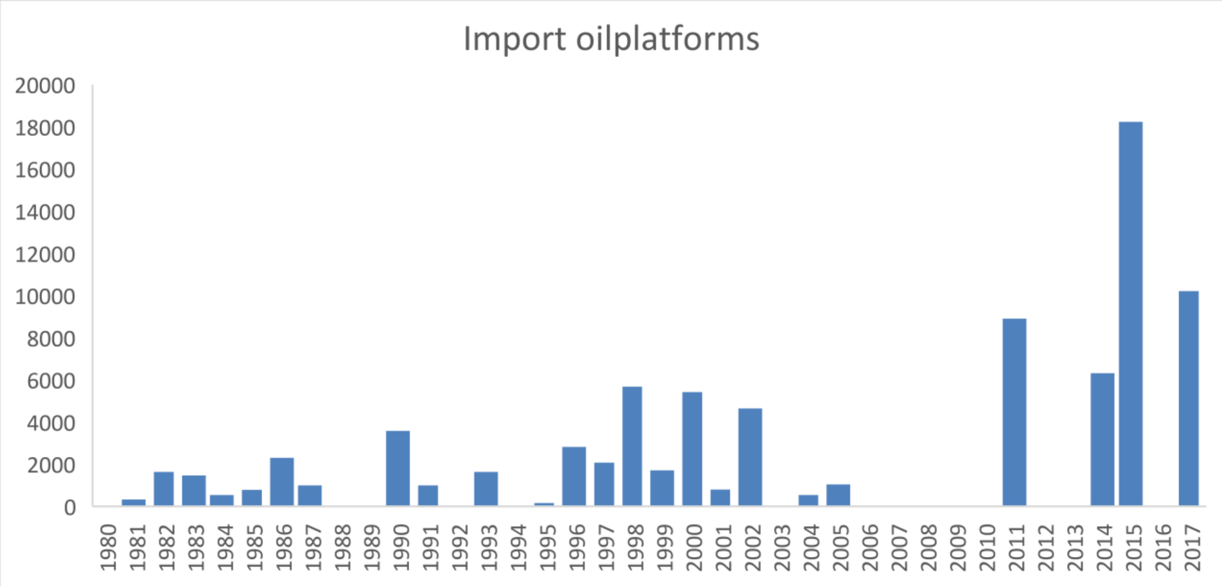

Figure 3-32 Import Oil Platforms (S. N. SSB, 2018).

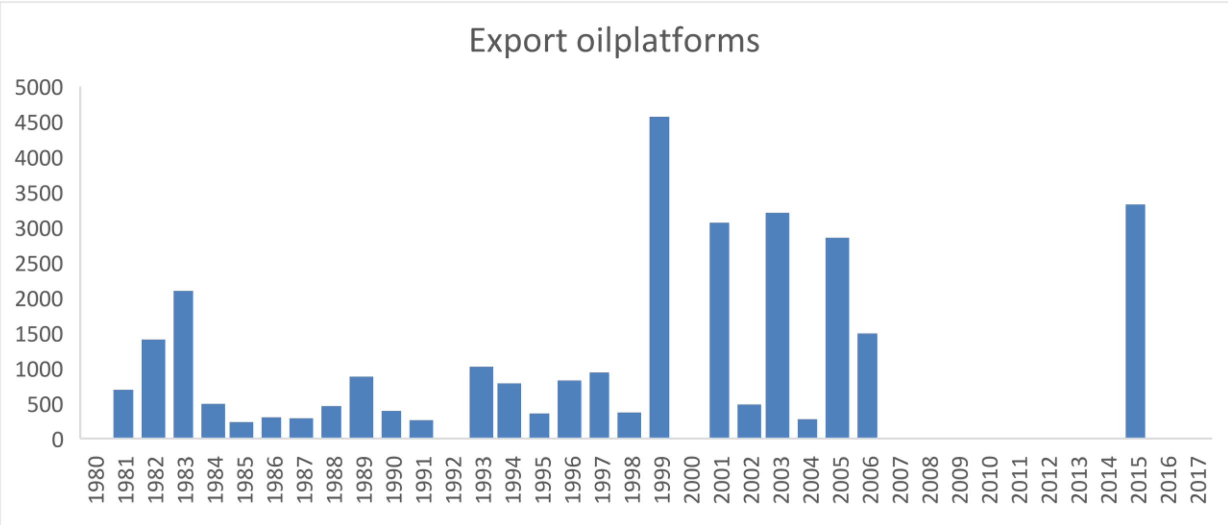

Figure 3-33 Export Oil Plaforms (SSB, 2018a).

Figure 3-32 contains number for the import of oil platforms to Norway, and Figure 3-33 has the export numbers. The values in these figures has not been deflated. It is apparent from the two export/import figures that more platforms have been imported than exported.

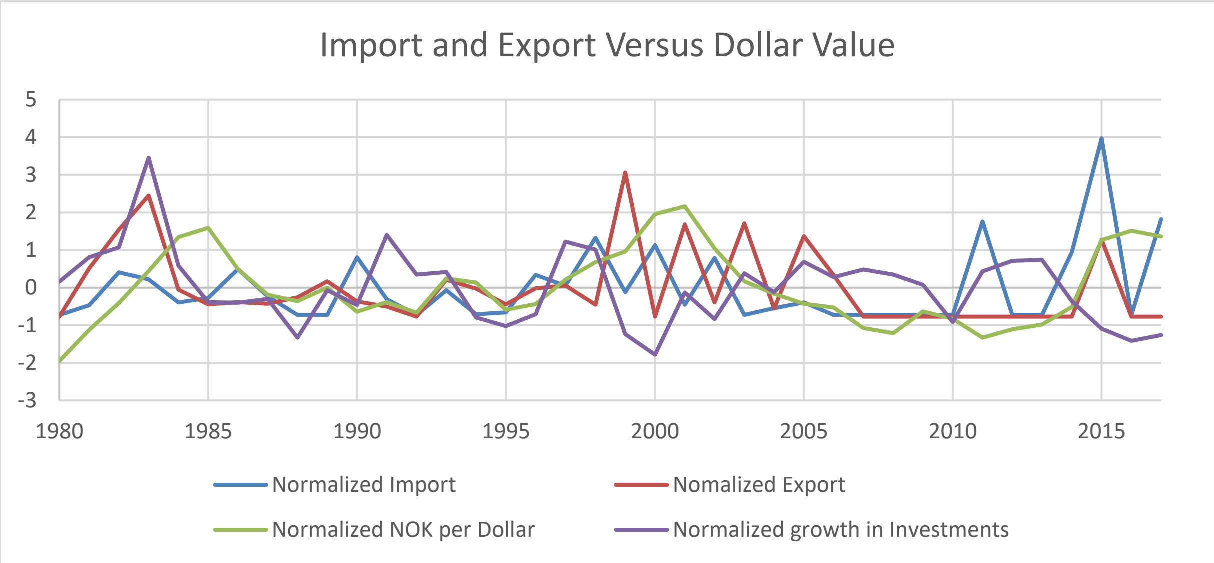

Figure 3-34 Normalized Values for Annual Export and Import of Oil Platforms, the Dollar vs NOK and Annual Change in Investments.

From Figure 3-34, both import, and export of oil platforms have a positive correlation of ca 0.3 to the Dollar. The annual change in investments have a negative correlation to the Dollar value of about -0.3 and the annual change in investments also have a correlation of ca -0.18 to import of oil platforms. Annual change in investments also have a correlation of 0.24 to export of oil platforms. The numbers used to derive Figure 3-34 are to sporadic to represent any significant results.

4. Discussion

The aim of this thesis is to investigate the similarities between crises in the Norwegian petroleum industry, and to find what caused the crises.

As a foundation for the discussion some important general trends have been investigated. To draw a conclusion of what happens before and after a crisis occurs, the underlying foundational trends in the industry should be accounted for.

This thesis is informed by data and historical accounts regarding; the international petroleum market, reports from the Norwegian government regarding cost overruns, the fiscal framework the industry operates in, historical accounts of consolidation and convergence between international and domestic oil companies and aggregated data series describing the development in the industry.

Important aspects of regulation that has changed from in the timeframe that is investigated:

The regulation of the petroleum industry started off as protectionist, there was a clear motivation to establish a strong Norwegian petroleum industry. Also, the government acted opportunistic when they increased taxes and fees during the oil price boom in predating 1986. The government move towards liberalization in the industry after the bust in oil price in 1986, one important aspect of this was the move towards a neutral tax system. That is only to tax profits. This would be less discouraging to international companies, as the taxes and fees to the government would be more predictable. One could say that the government minimized its risk regarding cash flow, in the early days of the petroleum industry by applying fees on volume produced, and through their option to increase ownership in fields. The governments risk exposure can be seen from their net cash flow, which is subject to large deviations during crises. As the industry progressed, the government gradually took more risk, as for example in 2005 when exploration cost could be reimbursed.

The global petroleum market:

This thesis does not closely investigate the global petroleum marked, but the sporadic and somewhat random movements and shifts in this marked has been elaborated. The balance between supply and demand in the oil marked is fragile, and unsuspected shifts in oil price should be expected within a 10-year perspective. The supply of oil is to a large degree subject to what the largest global suppliers of oil, such as OPEC, are able or willing to produce.

There are two distinct ways to compare the crises in 1986, 1998 and 2014. On is that, the size of the change in oil prices over a 3-year period[29] is a measure on how unlikely the price drop was. And the other one is by looking at the likelihood that oil prices should be what it is in light of long term trends. The first method is used in this thesis, as this accounts for the industry's

[29] The average time from a field is approved for development and till it produces a petroleum product.

ability to adapt to fundamental shifts in oil price, and it accounts for the fact that in the 1990s there was no long term increasing trend in the oil price.

Also, the sharp fall in oil prices in 2008 did not initiate a crisis in the Norwegian petroleum industry, due to the quick recovery of the prices. The investments in the industry dropped, but this can be attributed to falling prices across the board.

The oil price is a two-edged sword. While the price is high, it is obvious from multiple studies done on this subject and some of the analysis done in this report, that the industry, both international and domestic, will move towards utilizing the full available capacity from every segment of the industry. This results in rising costs. Also, in the Norwegian industry there is a mindset to fully exploit every resource available, this leads the industry to pursue riskier fields in times of high oil prices, thus companies are more exposed to falling prices. The high tax and the system for deducting costs can in some cases incentivize companies to be less risk averse.

When oil prices fall there is a period of low activity in the industry, less investment and the cash flow to the government is low, the Dollar gets more expensive thus making every Norwegian poorer. There seems to be an increase in fields shut down when oil prices fall. Shut down of oil fields occurred for the first time in 1993. This should be viewed in relations to the fact that in 1986 most producing fields on the shelf where relatively new, and consecutively many fields were old and closer to maturity in 2014. However, there seems to be a trend in that while the average age of oil fields gets larger the more fields will be shut down in periods of low oil prices.

The resources on the continental shelf, number of active fields and employed people:

The accumulated resources in producing fields has been declining and the average age of fields are increasing at the same time as the number of active fields has been steadily increasing.

This might, provide part of the explanation as to why employment numbers dropped significantly more in the 2014 crisis compared to earlier crises. While price of oil, employment and drilling costs plummeted, the produced volume of oil equivalents increased.

Consolidation amongst companies on the continental shelf:

The first wave of consolidation occurred in the late 1990s, this was initiated by the larger international oil companies, Statoil and Hydro also merged, but some years later. The argument for a merger between Statoil and Hydro was that, larger companies would have a larger pool of human resources and money, thus, be able to comprehend the ever-increasing risk and complexity in the industry. The total number of companies operating on the Norwegian Shelf did not see any large decrease. However, the number of medium-sized companies was sharply reduced from the late 1990s and towards 2002. Viewed in light of the NORSOK-initiative, that aimed to reduce number of interfaces[30], introduce industry standards and increase cooperation

[30] In this setting, interface refers to the interaction between to separate companies.

in projects on the NCS. The reduction in number of medium sized companies was probably on par with the consensus reach trough NORSOK.

The history of Kvaerner and Aker is a nice analogy to the business cycle in the petroleum industry. After the bust in oil prices in 1986, Aker acquired several companies, and expanded its business. The Aker concern gained several departments and expanded its operations to several new areas between the late 1980s and 1990s. In 1996 the oil related departments in Aker was gathered into one unit, and in in 2000 Aker started to acquire Kvaerner, these two companies were merged in 2004. From ca 2005 several new departments emerged from Aker, and Kvaerner was separated from Aker as an independent EPC company in 2011.

The large growth in companies on the NCS should be viewed in light of the growing numbers of active fields, and the increasing average age of these fields. This creates more room for companies to operate in small niches of the industry.

Outlook for the industry and its possible effect on initiatives to keep growth going:

In 1986, the petroleum industry was relatively new in Norway, no crises had occurred earlier, and there had been long periods of high profitability. This effectively means that the industry had not been through any hard periods. Thus, the improvement potential was large. The sharp decline in oil price prompted companies to improve its procedures, introduce technical improvements and government to refine the fiscal framework, some acquisitions and mergers also happened in the period after 1986. In the late 1990s the industry once again had to improve. This was done through technical improvements, consolidation between large oil companies and the introduction of new contract formats and logistical improvements. Also, the fiscal regime was further moved towards a neutral tax system in the early 1990s. the late 1990s and early 2000s, is characterized by an increase in cooperation between companies and introduction of standards that allows for a more effective supply industry.

In 2014, the potential for improvement, beyond the increased competition amongst companies in the supply industry, and a stronger commitment to industry standards, seems to be smaller. The growth potential in the industry is not as high as it was in the late 1990s, and certainly not as high as it was in the 1980s. The Barents Sea does represent the area with the largest growth potential after 2014, but this is a challenging area, both because of the weather in the area, but also because of the large distances and lack of infrastructure near the fields. The government offers one extra incentive for development in this area trough depreciation over 3 years, as opposed to 6 years in the North Sea and the Norwegian Sea. This could help increasing the Net Present Value of a project.

The number of people employed have been rising since the beginning of the oil industry's history in Norway, except from the years 2013 to 2017. The average number of people employed in oil and gas extraction per field on the NCS was declining before 2007 and after 2007 this number was somewhat stagnant.

5. Conclusion

The objective of this thesis is to analyze and compare historical and the recent economic crises in the Norwegian petroleum industry. The aim was to reveal similarities between the crises, how the crises manifested in the industry and what was done to mitigate the crises. The comparisons are viewed in light of fundamental long-term trends, both quantitative and qualitative, that has shaped the Norwegian petroleum industry.

The analysis reveals that there are few substantial similarities between historical crises. This can be attributed to changes in fundamental aspects of the industry; e.g. a decrease in "easy oil", an increasing number of active fields with respective increasing average age, and the diminishing potential for fundamental improvements in the industry.

These are all factors that in general express the increasing age of the industry, and the maturity of the fields. For fields that have been produced for many years, the properties of the reservoir changes, and increasing costs are needed to maintain a high recovery. Therefore, the historical and economical context that these crises initiated in differs.

Some factors of similarities of cause, industrial manifestations and efforts to mitigate the crises between the historical cases can be identified from the results:

- The overarching theme of periods of crises in the petroleum sector, is a low price of oil. The initiator of every crisis on the continental shelf has been a steep and unlikely large fall in the price of oil over the course of 1-2 years. This occurred in 1986, 1997-1999 and 2014-2016.
- Leading up to the crises, there has been a period of booming activities, in which there has consequently been a period where the cost of projects increases faster than the profitability from producing the petroleum. When oil production is highly profitable, many projects are initiated. This in turn, creates large cost overruns due to the lack of capacity for project development and the development of "experimental solutions".
- The most pronounced manifestation of the busts within industry in all periods of crisis has been a decrease in investment. Investments in exploration drilling is the first segment that is affected by the decrease in invested capital. The second area that is affected by a decrease in investment is the development of new fields. This occurs 1-2 years after the initial drop in oil price.
- The periods of low oil price prompt the industry to reduce its costs. On the upside, this has led to an introduction of new technologies, such as remotely operated subsea installations.
- The large cost overruns accompanied by reduction in profitability has in all three cases of a crisis, led to a period of acquisitions and mergers among the service and supply companies and the larger E&P companies.
- The industry moves toward commitment to new industry standards.

A fundamental difference between the crisis initiated in 2014 and the crises in 1986 and 1998 is that the investments in exploration, development of new fields and investments in producing fields, all fell three years in a row. This happened in light of a falling average volume of oil equivalents in producing fields on the NCS and an increasing average age of the fields on the NCS and a diminishing potential for improvements, beyond getting the business cycle in line.

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