FACULTY OF SCIENCE AND TECHNOLOGY

MASTER THESIS

Study programme/specialisation:
Industrial Economics

The spring semester, 2023

Open / ~~Confidential~~

Author: Vermund Leite &
Heine Johannessen

V. Leite .... Heine J. ....
(signature authors)

Course coordinator: Sigbjørn Landazuri Tveteraas

Supervisor: Kristin Helen Roll

Thesis title: Offshore Electrification - Cost-Benefit Analysis of the Balder/Grane Electrification Project: Assessing the Viability for National & Global CO_2 Emission Reduction

Credits (ECTS): 30

Keywords:

- Electrification
- Power From Shore
- Economic Analyses
- Environmental Impact Analysis
- CO_2 Reduction (National & Global)
- Energy Market
- Sensitivity Analyses

Pages: 72

+ appendix: 14

Stavanger, 14/06/2023

Preface

This master's thesis was a collaborative effort between Vår Energi ASA and the Faculty of Science and Technology, University of Stavanger. This study was completed during the spring semester of 2023 in Stavanger. The authors of the thesis are Vermund Leite & Heine Johannessen, students of Industrial Economics.

We would like to express our gratitude to the team at Vår Energi, including our supervisors and other contributors, for their guidance, information, and support throughout the completion of our master's thesis. Furthermore, we would like to thank our family, friends, and colleagues for their support throughout our academic journey. Through this research, we have gained a more profound understanding of the daily operations of an energy company, specifically their efforts towards enhancing the Norwegian economy, generating employment opportunities, and achieving global and national emissions reduction targets. We feel privileged to have had the opportunity to study such a relevant and rewarding topic.

------------------------------	------------------------------
Vermund Leite	Heine Johannessen

Universitetet i Stavanger

vår energi

Abstract

This master's thesis examines the Balder/Grane Electrification (BGE) project as a case study to evaluate its economic viability and environmental benefits by utilizing Power from Shore for the offshore facilities. The primary research question of this study is to assess the financial feasibility of the project and its potential to contribute to the reduction of both national and global CO_2 emissions. The study evaluates important factors such as net present value (NPV), internal rate of return (IRR), payback period, and CO_2 emissions to understand the potential benefits of the project.

By utilizing a combination of qualitative and quantitative data, this thesis integrates both qualitative and quantitative research methodologies. Through collaboration with Vår Energi and use of relevant reports and studies, this thesis provides analyses of the BGE project. To address uncertainties regarding future market trends and global CO_2 impact, research and data comparisons have been conducted to ensure the reliability of the estimates.

The economic analysis calculates a positive NPV for the BGE project at a 4% discount rate after tax, indicating a net economic gain. However, when using a 7% discount rate, the NPV turns negative. Furthermore, the Environmental impact analysis reveals that implementing power from shore as a solution has a significant potential for reducing CO_2 emissions both at the national and global levels. While the project successfully reduces CO_2 emissions on a national level, the analysis indicates that the global CO_2 reduction impact surpasses the reduction achieved at the national level. In other words, the effect of adopting power from shore leads to a greater overall reduction in global CO_2 emissions.

Based on the findings and results of the analyses, the thesis concludes that the BGE project with power from shore could be a promising and financially viable solution that holds great potential to reduce both national and global CO_2 emission. However, further evaluation of key input variables and additional analysis is required to address uncertainties and ensure the project's economic viability.

Table of Contents

List Of Figures

List Of Tables

Nomenclature

ABEX	=	Abandonment Expenditure
AC	=	Alternating Current
BGE	=	Balder & Grane Electrification
Boe	=	Barrel Of Oil Equivalent
CAPEX	=	Capital Expenditure
CH_4	=	Methane
CO_2	=	Carbon Dioxide
CO_2e	=	Carbon Dioxide Equivalent
DC	=	Direct Current
DR	=	Discount Rate
EØS	=	Det Europeiske Økonomiske Samarbeidsområde
ESG	=	Environmental, Social, And Governance
EU	=	The European Union
EU ETS	=	European Union Emission Trading System
FID	=	Final Investment Decision
FPSO	=	Floating Production Storage and Offloading
FPSO	=	Floating Production Storage and Offloading
GHG	=	Greenhouse Gas
GT	=	Gas Turbine
GWP	=	Global Warming Potential
IEA	=	International Energy Agency
IPCC	=	Intergovernmental Panel on Climate Change
IRR	=	Internal Rate of Return
KWh	=	Kilowatt-Hour
MJ	=	Megajoule
mmBtu	=	One Million British Thermal Units
MW	=	Megawatt
MWh	=	Megawatt-Hour
NCS	=	Norwegian Continental Shelf
NO2	=	Sørlandet
NOx	=	Nitrogen Oxides
NPD	=	The Norwegian Petroleum Directorate
NPV	=	Net Present Value
NVE	=	The Norwegian Water Resources and Energy Directorate
OPEX	=	Operational Expenditure
PFS	=	Power From Shore
POC	=	Point Of Connection
ROI	=	Return On Investment
Sm^3	=	Standard Cubic Meter
SSB	=	Statistisk Sentralbyrå
TTF	=	Title Transfer Facility
TWh	=	Terawatt Hour
WHRU	=	Waste Heat Recovery Unit
Yr	=	Year

1. Introduction

The global average temperature has risen 1.1 degrees since 1750 and melting glaciers and warmer sea temperature are causing the sea to rise faster than it has in the past. Globally, extreme weather and natural disasters such as floods, heat waves hurricanes and cyclones will occur more frequently (FN-Sambandet, 2023). Scientific evidence continues to show that it is extremely likely that global warming is caused mainly by human activities (NASA, 2023). As a result of this, the Paris Agreement entered into force in 2016. In the Paris Agreement, Norway has committed to reduce the emissions by at least 50% and up to 55% by 2030 compared to 1990 levels (Regjeringen, 2022b).

The oil- and gas industry is the largest source of emissions in Norway. 12.1 million tons CO_2 equivalents came from oil and gas extraction in 2021, which equivalates to ca. a quarter of all the CO_2 emission in Norway (SSB, 2022a). Most of the emission on the Norwegian continental shelf (NCS) comes from power production offshore using gas turbines. Replacing the gas turbines with power from shore or offshore wind turbines will therefore be crucial for Norway to reach their national climate goals. However, there are major disagreements between both researchers and politicians if electrification of the NCS with power from shore is a good measure to decrease CO_2 emissions globally.

Vår Energi, a leading independent oil and gas operator on the NCS, is committed to reducing its carbon footprint and contributing to the transition toward a low-carbon future. One of their main ambitions is to achieve a 50% reduction in greenhouse gas emissions from their operated fields by 2030. As part of this commitment, Vår Energi has initiated a project to decrease emissions on the Balder and Grane offshore fields by utilizing power from onshore sources. The electrification project is a joint venture between the Balder and Grane licenses where Vår Energi is the operator of Balder and Equinor is the operator of Grane.

1.1. Research Question & Goal for thesis

For this master's thesis, following research question has been developed in collaboration with Vår Energi:

"*Does the Balder/Grane electrification project provide a financially viable solution to reduce national and global CO_2 emissions?*".

The aim of this study is to conduct a screening of the electrification project, including an analysis of its economic and environmental impact. This will involve conducting CO_2 and fuel gas calculations, performing a net present value analysis, CO_2 abatement cost of the project, and calculating national and global CO_2 emissions. The purpose of this study is to evaluate the effectiveness of the electrification project as a means of reducing the carbon footprint, while also examining its financial viability. The results of this master thesis can provide valuable insights into the potential benefits of investing in similar electrification projects in the future.

To achieve these objectives, an upright methodology will be applied. This will involve a broad review of relevant literature, including industry reports and academic studies, to identify best practices and benchmarking data. To provide the best possible assessment of the economic and environmental impacts of this electrification project, available data from Vår Energi and relevant assumptions are needed. Chapter 2, 4 and 5 will provide more information on methods used in this master thesis.

1.2. Structure of the thesis

This thesis consists of 7 main chapters. These chapters provide relevant theory, data and methods utilized to do different analysis and answer the research question. Chapter 2-4 will provide insight into theory and general background before chapter 5 presents the methods, data and assumptions considered to do further work. This thesis examines the Balder/Grane Electrification (BGE) project as a case study to assess its economic viability and environmental impact. The focus of the thesis is twofold: conducting economic analyses of the electrification project and evaluating its environmental implications on both national and global scales. Additionally, the thesis includes calculations related to CO2 emissions and fuel gas consumption offshore.

After chapter 5 has presented the relevant data used in the analyses, the results and findings of both the economic and environmental impact analyses and the sensitivity analyses done will be discussed in chapter 6. It will also include calculations and reflections on the results. The discussion and results presented in this chapter will form the basis of the conclusion in Chapter 7. Additionally, a chapter on "Future Research" will provide recommendations for future studies that could contribute to new topics of research.

The thesis will include three appendices related to the work done in Excel. Appendix 1 will present the data, assumptions, and calculations performed for the analyses, including calculated CO_2 emissions and fuel gas consumption for the case study. Appendix 2 will demonstrate the step-by-step calculations leading to the results, covering both the environmental impact and economic analysis. In Appendix 3, the Excel sheet will display the actual Excel formulas used for the calculations.

2. Method

Research methodology is the specific procedures or techniques used to identify, select, process, and analyze information about a topic (University of the Witwatersrand, 2023). This chapter will go through the methods used to answer the research question.

2.1. Qualitative & Quantitative Method

Both quantitative and qualitative research has been widely used in this thesis. The combination of qualitative and quantitative research methods has enabled the thesis to provide a more comprehensive and reliable analysis of the project’s financial viability to reduce national and global emissions.

- Quantitative research has been used developing models to calculate the projects profitability, abatement cost, fuel gas consumptions and emissions (national and global). This method involves collection and analysis of numerical data used in the calculations. The approach has given the thesis a quantitative basis to evaluate project costs and benefits.
- Qualitative research has been used to gain knowledge about the economics and global impact of electrification projects. The global impact of electrification projects can be complex, and qualitative research has been necessary to make informed assumptions when developing the models.

2.2. Data Collection

The theoretical foundation for this thesis is based on data from a variety of sources. Close collaboration with Vår Energi has provided both qualitative and quantitative data through conversations with employees and access to relevant datasheets. Data which is also used to make necessary assumptions for the thesis.

Reports and studies from respected organizations like SSB, IEA, Konkraft, NPD, and NVE have also been utilized. However, due to the complexity of forecasting future market trends and the global CO_2 impact, some of the data used in the analyses has its uncertainties. Therefore, it has been critical to do research and compare various sources to ensure the reliability of the estimates.

Simplified price forecasts for future electricity and gas prices in the period of 2030-2050 have been based on data from both NVE and Equinor. The studies "Elektrifisering av olje- og gassektoren – har det global klimaeffekt?" (Thema Consulting Group, 2023) and “Netto klimagassutslipp fra økt olje- og gassproduksjon på norsk sokkel" (Rystad Energy, 2023) have played a notable role in this thesis.The data and information from these studies have served as a valuable source for the development of the environmental impact analysis, specifically focusing on the global CO_2 emissions influenced by electrification of offshore facilities on the NCS. Both Rystad Energy and Thema Consulting Group are trustworthy sources. However, it's important to keep in mind that the estimations in their studies are complex, and there are uncertainties related to them.

2.3. Excel Models

To answer the research question presented in chapter 1.1, two excel models have been developed to analyze the economics and environmental impact of the electrification project. As energy and volumes of petroleum (oil, condensate, Natural gas liquids and gas) can be quantified using multiple different units, much of the data obtained to create the excel models has been converted for the calculations to be correct. Unit converters from the websites of Equinor and Norwegian Petroleum has been useful tools to convert units quickly and precisely, (Equinor, n.d.-b) (Norsk Petroleum, n.d.-b).

The first model is an Economic analysis, which includes calculation of NPV, IRR and payback period of the case study (electrification project). These financial metrics are commonly used for evaluating and comparing different investment opportunities. The abatement cost is also integrated into the model to determine if the investment has socio-economic benefits. The environmental impact analysis is performed by developing a model that estimates the reduction in national and global CO_2 emissions from the electrification project. Estimates of reduced/saved CO_2 emissions and fuel gas consumption from the offshore facility are not only utilized to assess their global CO_2 emission impact, but also play a crucial role in economic analyses as a potential revenue source. This is primarily due to CO_2 taxes, quotas, and additional incentives are the main factors driving financial opportunities, including the potential for increased gas supply to Europe.

Overall, the financial analyses provide insights into the economic viability of the project, while the environmental impact analysis helps to determine the project's contribution to the national and global climate goals, as well as socio-economic benefits. By incorporating both analyses, the thesis can provide a more comprehensive and balanced assessment of the electrification project's overall impact. Chapter 5 will give more insight on methods, data and assumption utilized in the analyses.

3. General Background

3.1. Today's Climate Gas Emissions: Understanding the Current Situation

This chapter examines the petroleum industry's role in contributing to Norway's carbon footprint, particularly its significant CO_2 emissions. It provides an overview of the country's greenhouse gas emissions across various sectors and delves into the different sources of emissions from the petroleum sector.

3.1.1. The Paris Agreement & Climate Challenges

Climate change is one of the main challenges of our time, with about 70% of global Greenhouse gas (GHG) emissions being energy related. In order to reduce these emissions, rapid and profound system changes are required in most sectors in the coming decades, including changes in energy production and consumption patterns (Meld.St.36 (2020-2021), p.6-7 & p.11-13).

The Paris Agreement is a global framework aimed at addressing climate change and its impacts. It has secured commitments from almost all nations worldwide to collectively strive for a shared long-term goal of limiting the increase in the global average temperature to well below 2 degrees Celsius. To accomplish this, the primary objective is to achieve the long-term goal of limiting global warming. This involves taking immediate action to reach the peak of greenhouse gas emissions and then making significant reductions in line with the latest scientific knowledge. The aim is to establish a state of equilibrium, known as climate neutrality, where human caused emissions are balanced by the removal of greenhouse gases, ideally by the latter half of this century. However, this will require powerful reductions in global emissions and a rapid and comprehensive transformation in all countries and all sectors (Meld.St.36 (2020-2021), p.6-7).

Norway has made an agreement with the EU and Iceland to reduce greenhouse gas emissions by at least 40 percent compared to 1990 levels by 2030 as part of meeting the climate goals of the Paris Agreement. In February 2020, Norway submitted an enhanced climate target for 2030 under the Paris Agreement. This target aims to reduce emissions by at least 50 percent, and potentially up to 55 percent, compared to the reference year of 1990. The Norwegian government aims to fulfill this strengthened goal in collaboration with the European Union (EU). The EU has also increased its own emissions reduction target for 2030 to at least a 55 percent reduction in net emissions. To reach these goals, Norway is focusing on promoting the use of alternatives to fossil fuels, with electricity as a key emission free energy source. This is a crucial element in the country's efforts to transition to a low-emissions society by 2030 (Meld.St.36 (2020-2021), p.6-7 & p.11-13).

GWP100 is the measure of GHG gasses global warming potential in a 100-year perspective, relative to the warming potential of CO_2. Methan (CH4) has a GWP100 factor of 25, meaning that it has a 25 times greater warming potential than CO_2 over a 100-year period (DNV GL, 2015, p.28). However, when considering the total volume of GHG emissions on the NCS, CO_2 is 20 times more damaging to the climate than CH4 and is by far the most important GHG released on the NCS from a GWP100 perspective (DNV GL, 2015, p.5). Starting from 1880, Figure 1 indicates that there has been a strong correlation between the concentration of atmospheric CO_2 and temperature (El-Montasser & Ben-Salha, 2019, p.587).

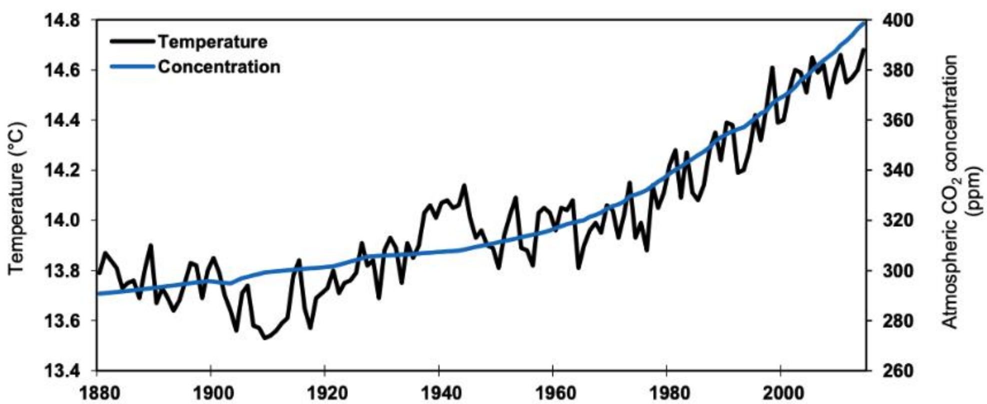


Figure 1: The correlation between atmospheric concentration of CO_2 and average global temperature

3.1.2. Greenhouse Gas Emissions in Norway's Petroleum Sector

In 2021, Norway's total GHG emissions corresponded to 48.9 million tons of CO_2-equivalent from a GWP100 perspective, with the petroleum industry being responsible for a significant portion of these emissions. At 12.1 million tones, or 24.7% of the total emissions, the petroleum industry remains one of the largest contributors to Norway's overall carbon footprint. Figure 2 below shows the total greenhouse gas emissions in Norway in 2021, divided into different sectors. The numbers are obtained from the Norwegian Environment Agency and Statistics Norway (Miljøstatus, 2022).

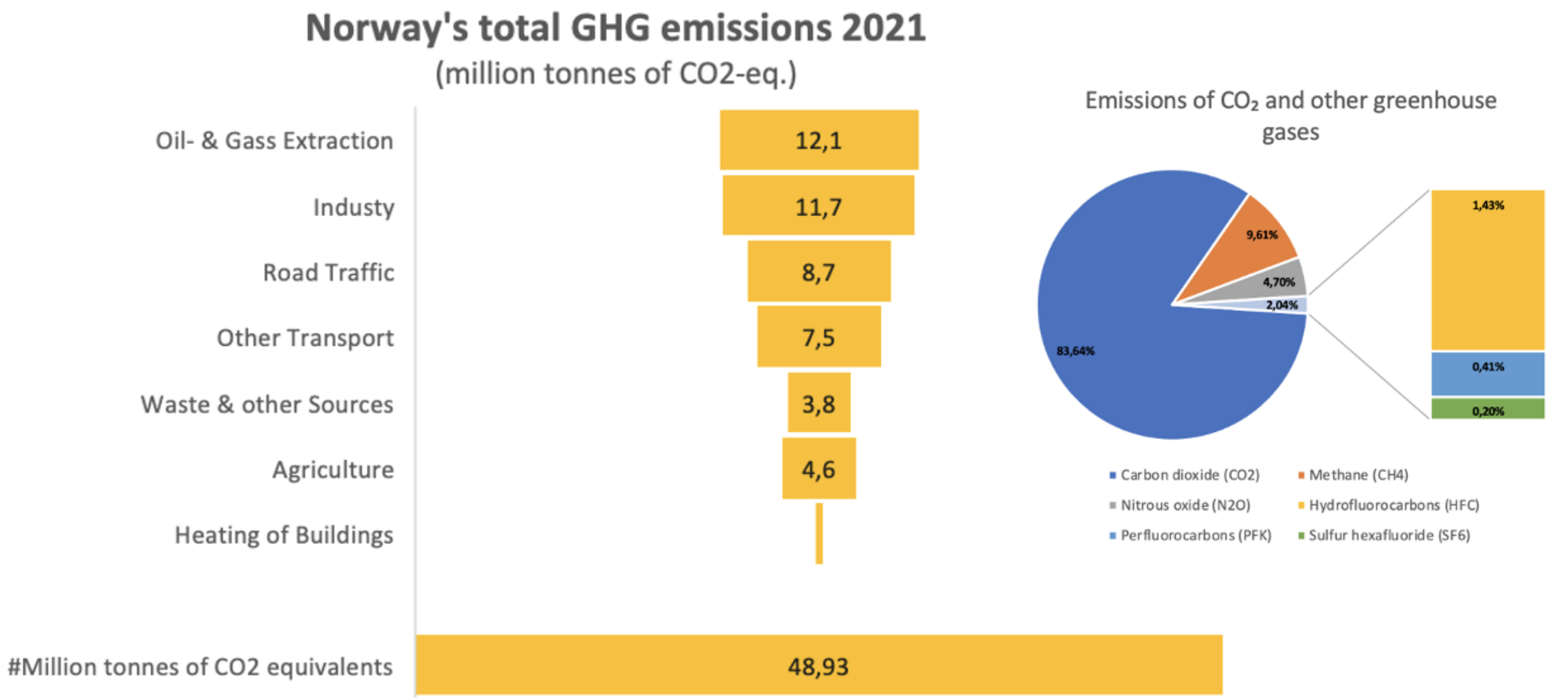


Figure 2: Total GHG emissions in Norway in 2021, divided into different sectors & percentages of the emissions.

The oil and gas industry is a major contributor to air pollution, with the combustion of natural gas and diesel in turbines and engines being the primary sources of emissions. Additionally, flaring of natural gas is allowed only for safety reasons, but still contributes to air pollution. The release of hydrocarbon gases directly into the atmosphere through cold venting and leaks, along with emissions from oil loading and well testing, further contribute to the issue. Figure 3 shows the Distribution of GHG emissions in the petroleum sector by emission sources. (Norsk Petroleum, 2022)

The amount of power generated by gas turbines and diesel engines on an oil platform can vary depending on the specific platform and its power requirements. However, in general, gas turbines and diesel engines are used as the primary power sources on oil & gas platforms, with other sources of power potentially also being used. Reducing emissions from gas turbines and diesel engines is important to lessen the negative environmental impact of the oil and gas industry. Electrifying oil fields has emerged as a solution to achieve this. The shift towards electrification is not only a solution to reduce GHG emissions on the NCS but can also contribute to reducing emissions nationally and globally.

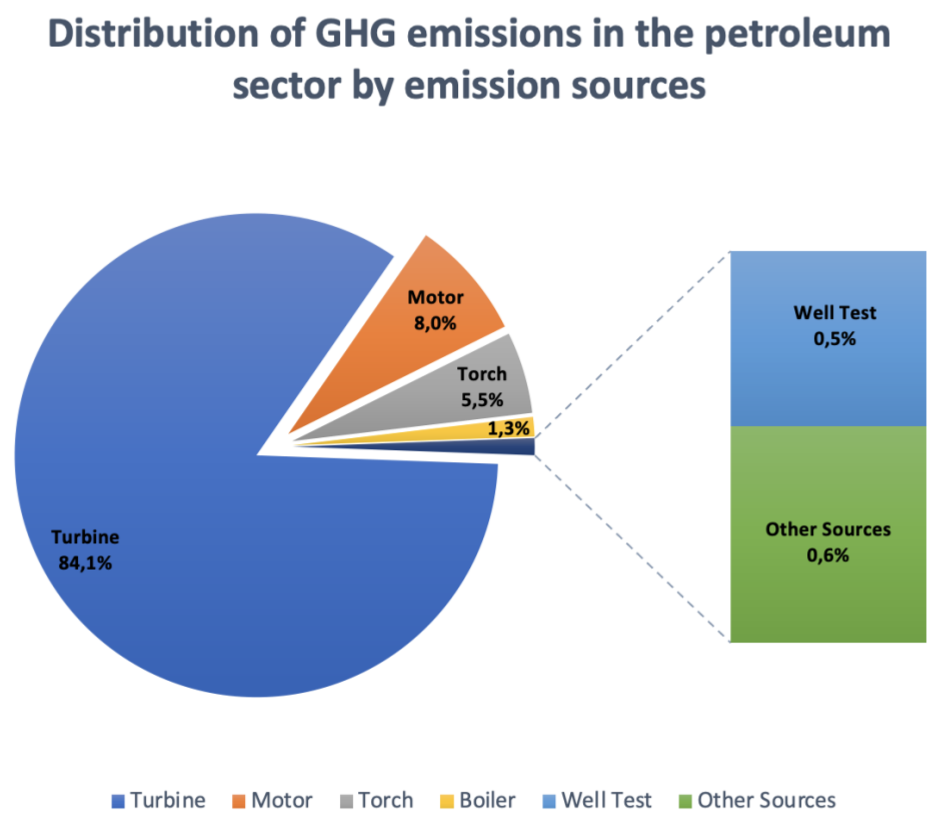


Figure 3: Distribution of GHG emissions in the petroleum sector by emission. Made with data from the Norwegian Petroleum Directorate (Norsk Petroleum, 2022).

In this context, leading companies such as Vår Energi in Norway have made a commitment to a more environmentally friendly petroleum production. Vår Energi has a clear ambition to become an ESG (Environmental, Social and Governance) leader, while becoming a net-zero producer by 2050. They have adopted various strategies to achieve this, and one important approach is to electrify their offshore assets on the Norwegian Continental Shelf. This means they will use electricity from either onshore power sources or offshore wind turbines to power their operations instead of relying solely on traditional energy sources. By making this shift, Vår Energi aims to significantly reduce their carbon footprint and contribute to a more sustainable future.

3.2. Vår Energi's ambitions to reduce GHG Emissions

In a world facing pressing environmental challenges, organizations like Vår Energi are stepping up to make a difference. With a deep sense of responsibility towards the planet and the communities they operate in, Vår Energi has embraced the principles of Environmental, Social, and Governance (ESG). By prioritizing safe operations, emission reduction, and value creation, Vår Energi aims to be a leader in promoting sustainable practices. Following statement by Torger Rød, CEO at Vår Energi confirms this:

"*It is important that we are responding to the ESG and being ESG leader. It is about safe operations, minimizing emission and value creation from society and local communities. Where we are operation and have activities, we are going to create activates and value. This is integrated in our business, strategy and who we are, hence very important for us.*

Our vison is to deliver a better future, that is about energy security and low emission. We are also committed and utilizing the sustainability goals actively to really set direction and framework on how we work." - Torger Rød, CEO at Vår Energi. (Rød, T., 2023, 1:03:20)

Vår Energi is a leading independent oil and gas operator on the NCS. The company has set ambitious goals to become the safest operator, the preferred partner and a leader in sustainability. They have made a commitment to reduce their carbon footprint and playing a role in the transition towards a low-carbon future. This commitment is reflected in some of Vår Energi' main ambitions (Vår Energi, 2021, p.6).

1. 50 % reduction in scope 1 GHG emissions from operated assets within 2030
2. Net zero emissions in scope 1 and 2 by 2030.
3. Near zero emissions from operated assets by 2050

The baseline for the goals is 2005. Scope 1 covers direct GHG emissions from operated assets and partner operated assets, while Scope 2 covers emissions that the company makes indirectly (e.g office buildings and offshore electrified assets). To be able to reach their goals, Vår Energi have initiated an electrification project to reduce emissions on the Jotun FPSO and Ringhorne facilities, for which Vår Energi are operators, as well as the Grane field, operated by Equinor. The base case is to provide the facilities with power from shore. Vår Energi are also exploring alternative options to minimize their carbon footprint, which includes considering offshore wind as a renewable energy source. This approach aims to contribute to a more sustainable energy mix.

3.3. Supply Of Power and Heat - Offshore Facilities

Electrification is the process of replacing fossil fuel power sources on offshore platforms with renewable energy sources, which helps to reduce carbon emissions. The concept of "Electrification with power from shore" involves abandoning the use of gas turbines powered by natural gas extracted offshore and instead using cables to transmit electricity from shore (Equinor, n.d.-a). Currently, most offshore platforms rely on gas turbines that use natural gas extracted offshore for power generation (Norsk Petroleum, 2022). As the shift to power from shore reduces the amount of natural gas combusted offshore, a greater volume of gas is enabled to be exported to Europe. This chapter will consider three different methods to supply power and heat to offshore facilities.

3.3.1. Gas turbine Cycle

Offshore oil and gas facilities commonly rely on gas turbines to supply both heat and power. One prevalent layout for offshore installations is the Gas Turbine Cycle, which employs simple gas turbine cycles. In this system, the power generated by the gas turbines covers the power demand, while waste heat recovery units (WHRUs) extract the thermal energy available in the gas turbine exhaust gas to supply process heat (Metro Services, 2020). The GTs + WHRU system enables local offshore power generation to meet the plant's energy demand without drawing power from onshore sources (Riboldi & Nord, 2017, p.866-867).

Each installation is equipped with an independent power generation system (GTs + WHRUs) to ensure energy autonomy. Typically, offshore facilities are equipped with one or more turbines to provide heat and power throughout the plant's lifetime. The strategy related to load and turbine availability varies among offshore facilities, but typically the load allocation strategy between the operating gas turbines considers splitting the total load equally between them (Riboldi et al., 2019, p.4).

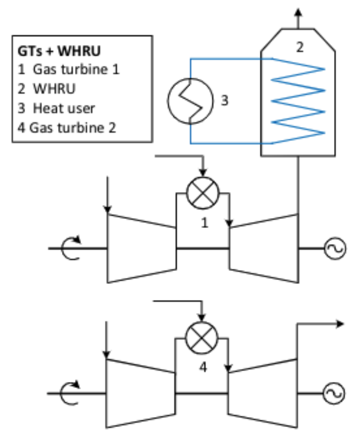


Figure 4: Schematic of the GTs + WHRU (Riboldi & Nord, 2017, p.867)

The efficiency of gas turbines plays a crucial role in their use as a source of power generation. In simple terms, gas turbine efficiency refers to the ratio of energy converted into usable power by the turbine to the energy input into the system. The efficiency of gas turbines is influenced by several factors, including the design of the turbine, the operating conditions, and the quality of fuel used. On offshore installations, the efficiency of gas turbines typically ranges between 25-35%, depending on the type, age, and load operation of the facility. By contrast, the efficiency of gas power plants, particularly combined cycle power plants on land in Europe, is around 50-60%. Apart from design and maintenance, the efficiency of gas turbines can be further improved through the adoption of waste heat recovery units (WHRUs). These units capture and reuse waste heat from the turbine's exhaust gas to generate additional power, thereby increasing the overall efficiency of the system. (Konkraft, 2021, p.18).

However, it is important to note that the operating conditions of the turbine also play a crucial role in determining its efficiency. For example, running the turbine at high temperatures and pressures can enhance its efficiency, but it may also reduce its lifespan. Therefore, a balance must be struck between the efficiency and the longevity of the turbine to ensure optimal performance and longevity. The efficiency of turbines can also vary based on the load they are operating at. Running a turbine at a low load can result in reduced efficiency, while running it at high load can result in increased efficiency. (Cuviella-Suarez et al., 2019, p.724)

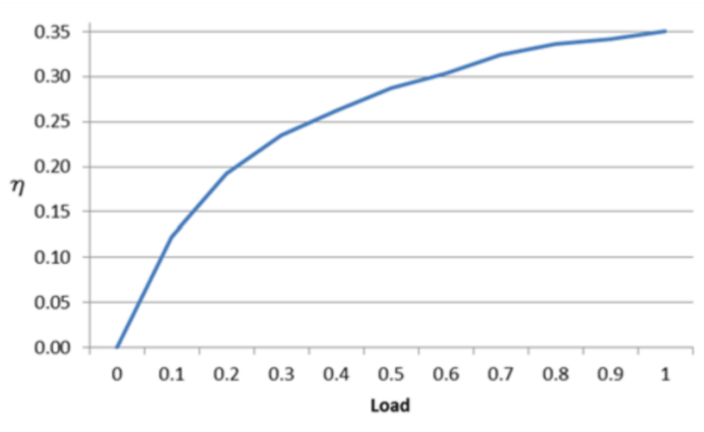


Figure 5: Efficiency of a gas turbine versus load (Cuviella-Suarez et al., 2019, p.724).

3.3.2. Full Electrification

One approach to reducing local gas consumption in offshore facilities is full electrification, this involves complete electrification of the facility, with onshore grid being the primary source of power (Riboldi et al., 2019, p.5-6). This method of utilizing shore power (PFS) has been shown to significantly reduce the amount of gas burned locally, resulting in a greater demand for gas compression and output. In addition to meeting the power needs, this approach also provides the required heat using electric heaters installed on the platforms. This strategy of full electrification with PFS can effectively cover both power and heat demands of offshore plants (Gravdal, 2022, p.21).

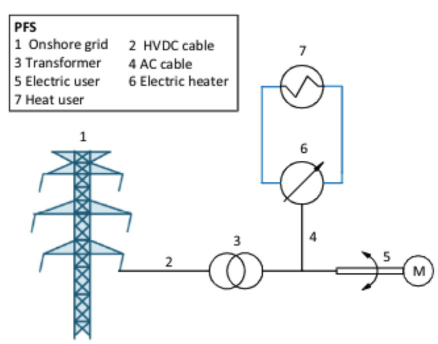


Figure 6: Schematic of the PFS (Riboldi & Nord, 2017, p.869)

3.3.3. Part Electrification

Part electrification is a hybrid from the two previous approaches. Gas turbines (GTs) and waste heat recovery units (WHRUs) are used to locally produce heat, while the remaining power demand is met by power from shore (PFS). To optimize CO_2 emissions, a constrained optimization process determines the appropriate load balance between offshore power generation and onshore power supply. However, using gas combustion for heat production results in reduced gas export and increased CO_2 emissions compared to PFS (Riboldi et al., 2019, p.5). When using turbines for only heat generation the load on the turbine is usually lower, which results in a lower turbine efficiency (shown in figure 7 below.)

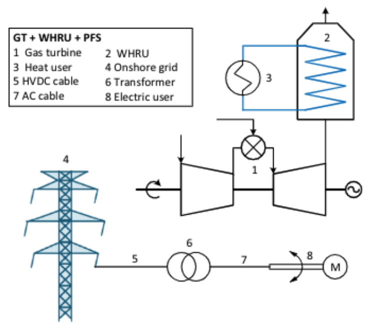


Figure 7: Schematic of the GT+ PFS + WHRU (Riboldi & Nord, 2017, p.868)

3.3.4. Power from shore

Several offshore fields in Norway have installations that are powered by electricity from shore, and these fields contribute significantly to the country's oil and gas production. There are plans in place to have even more installations powered by electricity from shore in the coming years (NPD, 2020, p.26). Currently, the Troll, Gjøa, Ormen Lange, Valhall, Martin Linge, Edvard Grieg, Ivar Aasen, Goliat, and Johan Sverdrup fields have installations that are powered by electricity from shore. The fields and facilities receiving power from the shore are represented in the figure below, which also illustrates the evolution of power transmission from land to the offshore sector since 1996. The amount of power transmitted has significantly increased since 2008 (Andreev & Skulstad, 2020, p.13). Electrification of the continental shelf will require 22.5 TWh in 2030, compared to 4 TWh in 2018. The power requirement for the remaining electrification projects is estimated to be around 10 terawatt hours (Nilsen, 2022).

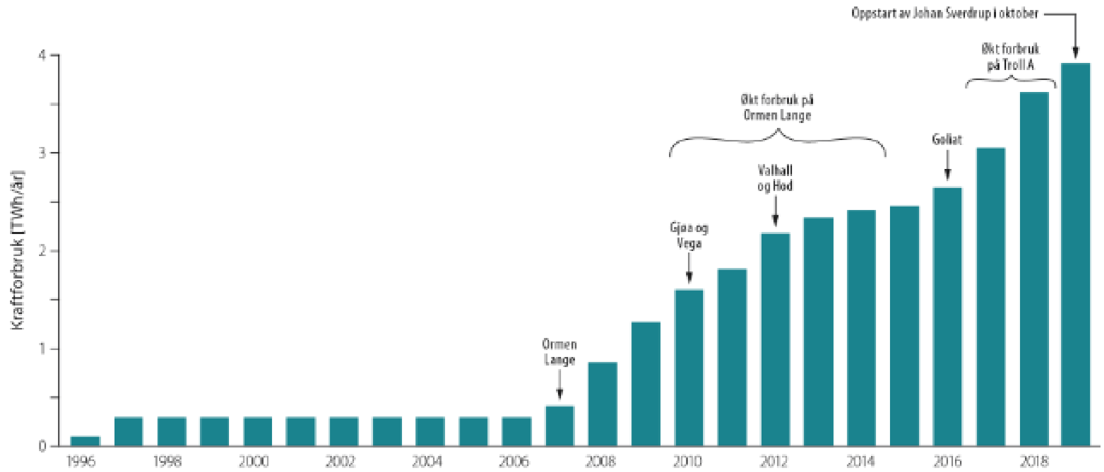


Figure 8: Development of power transmission from shore to the offshore sector (Andreev & Skulstad, 2020, p.14).

Power from shore is a highly effective measure for reducing greenhouse gas emissions in offshore oil and gas operations. This involves transmitting power to facilities through cables from the onshore power grid, eliminating the need for on-site generation using gas or diesel.

The two ways of transmitting power from shore are direct current (DC) and alternating current (AC). DC is ideal for long-distance transmission of large amounts of power. Nevertheless, a significant challenge of DC transmission is the requirement to convert power to DC onshore to align with the DC power grid and infrastructure. Then the converted power needs to be converted back to AC for use in offshore installations, necessitating the use of heavy, space-consuming, and expensive converter equipment (Gravdal, 2022, p.21). In contrast, AC transmission does not necessitate conversion, resulting in lower costs due to the reduced need for heavy and extensive equipment at both ends. However, AC transmission has limitations regarding long-distance power transmission.

Overall, the benefits of power from shore make it a valuable strategy for reducing emissions in offshore oil and gas activities, with the choice of DC or AC transmission depending on factors such as distance, cost, and existing infrastructure (NPD, 2020, p.23). Figure 9 illustrates the various offshore installations that are electrified from shore, taking into account the distance from shore, the power supply and both AC and DC transmission.

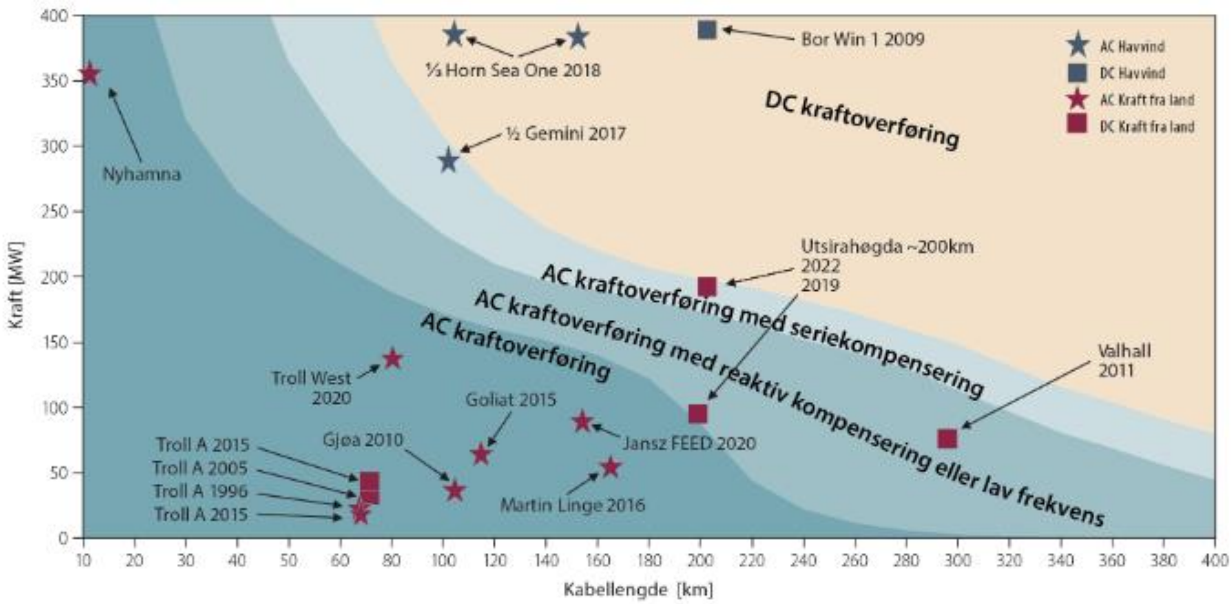


Figure 9: Different offshore installations as a function of power supply and cable length (NPD, 2020, p.23)

3.4. Environmental effect of electrification with PFS

When the NCS is provided with PFS, the emissions will be reduced nationally. However, electrification projects will also affect the power market in Europe and the global gas market. This chapter will go through how electrification projects on the NCS affect the global environment through the power-, gas- and quota market.

3.4.1. Power Market

Norway has the greatest proportion of electricity from renewable sources in Europe and exhibits the lowest emissions from its power industry. The Norwegian power production was 145,9 TWh in 2022 with hydropower as the largest source, as illustrated in figure 10 (SSB, n.d.).

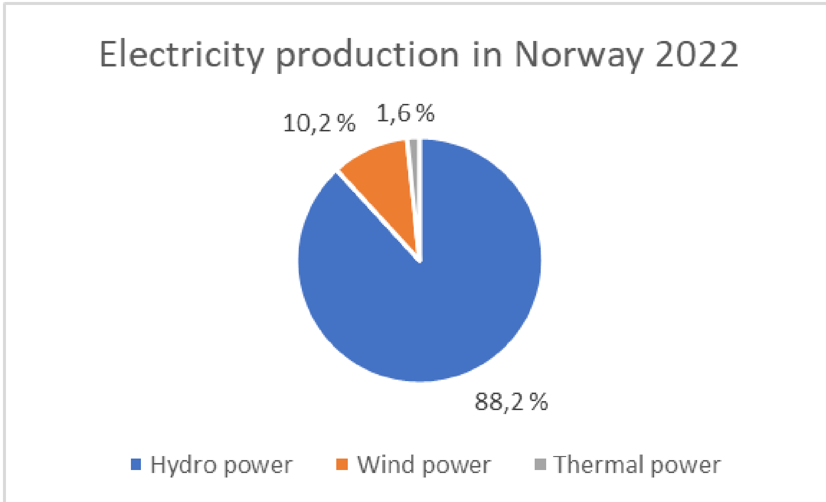


Figure 10: Electricity production in Norway, 2022. Made with data from SSB statbank.

As there are low emissions associated with power production, replacing offshore gas turbines with power from shore will reduce the emissions nationally. However, electrification of the NCS does not only have an effect on the power market nationally. Norway is a part of the Nordic single power market which is divided into different price areas. The Norwegian power market is also connected with direct cables to Great Britain, Netherlands, and Germany. Figure 11 shows the power flow between different price areas. The prices are a result of the supply and demand for power in different price areas and the power flow from low-price areas to high-price areas (Statnett, n.d.)

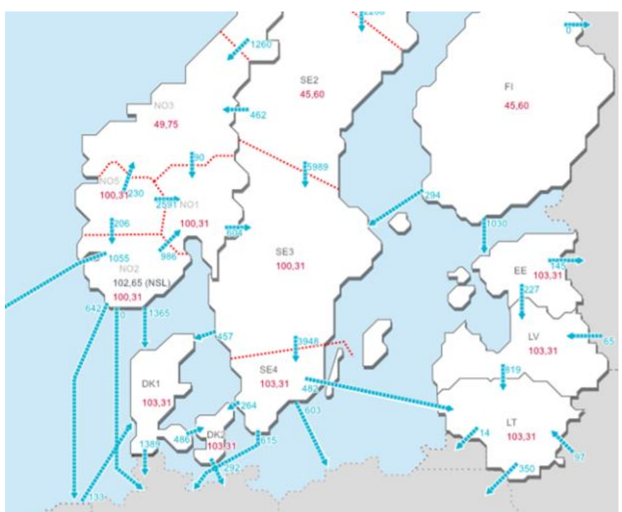


Figure 11: Nordic power flow 21.03.2023. Blue arrows illustrate the direction of flow, and the red numbers show price (Euros/MWh) for each price-area. (Statnett, n.d.)

Thema Consulting Group published a study report 06.01.2023 about the global effect of electrification of the oil- and gas sector in Norway. They estimated that emissions from quota-obliged countries in Europe will be reduced with 80% of the reduced emissions on the NCS (Thema Consulting Group, 2023, p.1). This estimate only considers the power market in Europe and does not consider the global effect of increasing gas production on the NCS.

When a new electrification project becomes known to the market it changes the expectation of future supply and demand. An electrification project with PFS increases the demand for power which will lead to higher power prices. According to Thema, increased demand in the short term is covered by increased prices or increased production (typically gas and coal) on existing power plants. If increased demand and prices is expected in the long term however, the market participants will invest in new power plants. Electrification projects are time consuming and are known to the market several years before it is realized. Thema have therefore assumed that the production capacity will to a large degree already be adapted when the power demand increases (Thema Consulting Group, 2023, p.11-12). Investments in new power plants are partly driven by politics and partly driven by market competition. Because of a stricter climate policy, an increase of coal-power capacity is not applicable. Increased power production will be based on a mix of gas and renewables instead. As a result, the emissions from increased power production in Europe are expected to increase significantly less compared to the reduced emissions on the NCS (Thema Consulting Group, 2023, p.11-12).

3.4.2. Gas Market

Gas is an important energy source in Europe. It is mostly used for heating buildings, power generation and in the petrochemical industry (Norsk petroleum, 2023b). Gas from Norway covers approximately 20-25 % of the gas demand in EU and United Kingdom (UK). A total amount of 117.7 billion Sm^3 natural gas was exported from Norway in 2022 (SSB, 2023).

The Norwegian pipeline network is integrated with the three onshore gas processing plants Kårstø, Kollsnes and Nyhamna. The plants receive rich gas from the fields and undergo separation to obtain dry gas for transportation. The receiving terminals are located in Germany, Belgium, France and UK.

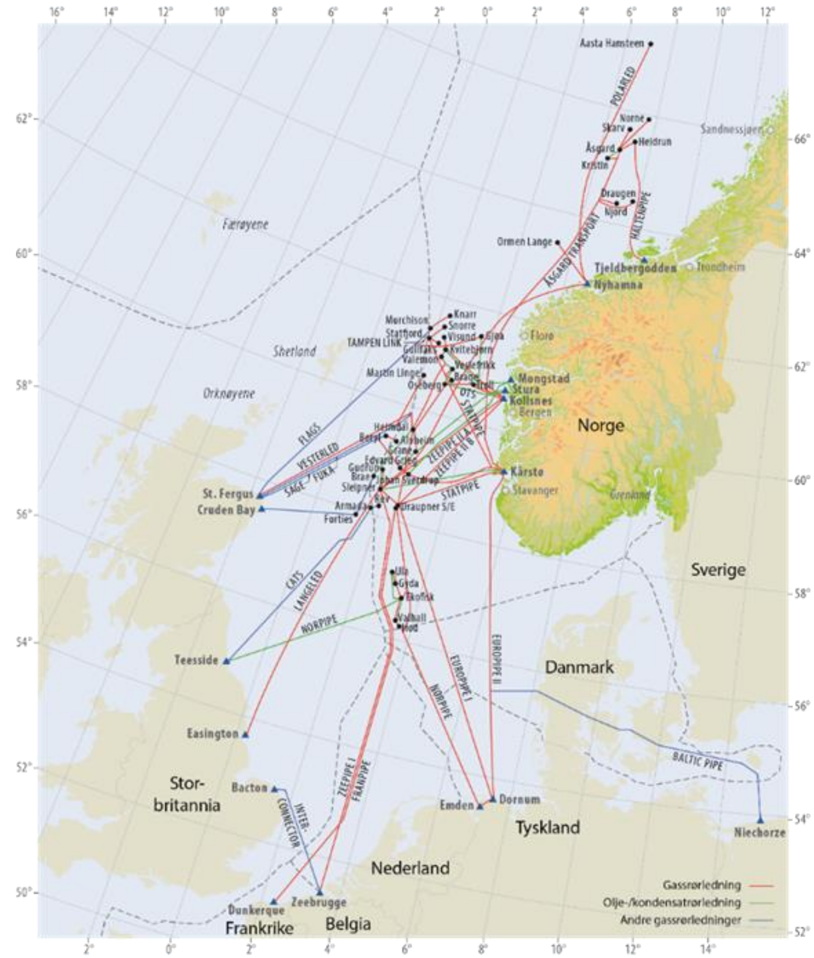


Figure 12: Pipelines on the NCS (Norsk petroleum, 2023a)

When gas turbines are replaced with power from shore, there will be more gas left over than can be exported. According to KonKraft's status report from 2021, the Norwegian gas exported to Europe are used far more efficient than on the NCS. About 30 percent of the gas in EU and the UK is used in gas-fired power plants and 40% is used in households and commercial buildings. The efficiency of gas-turbines used on the NCS usually are between 25-35%. Gas-fired power plants and especially combined cycle gas-turbines in Europe usually achieve an efficiency of 50-60% and the use of gas in households and commercial buildings is above 80% more efficient than on the NCS (Konkraft, 2021, p.18).

The environmental impact of electrification through the gas market is influenced by more than just how efficiently the Norwegian gas is used. Increased supply of gas to Europe will affect the gas market globally as it will reduce EUs gas import from countries outside of Europe (Thema Consulting group, 2023, p.13). Rystad Energy released a report in February 2023 about the global climate effect of increasing oil- and gas supply on the NCS. An increased supply of gas from Norway will naturally lead to an increased demand of gas in Europe. However, Rystad estimated that 123 kg CO_2 equivalents will be reduced globally for every barrel of oil equivalent (BOE) gas produced on the NCS (Rystad Energy, 2023, p.3). Their analysis is based on a three-step model that will be used as a part of the case study for this thesis (Chapter 5.5).

3.4.3. EU Emissions Trading System

Carbon tax and emission quotas are the two main instruments to achieve cost-effective decrease in GHG-emissions. The EU Emissions Trading System (EU ETS) is the world's largest carbon market. Norwegian companies have been a part of the EU ETS through the Agreement on the European Economic Area (EEA) since 2008 (Regjeringen, 2020). The system covers CO_2 emissions from electricity and heat generation, energy-intensive heavy industries (e.g., the oil- and gas industry) and civil aviation (European Commission, n.d.-a). EU ETS works as a cap-and-trade system and is designed to reduce GHG emissions within EU. Companies are allocated a certain amount of emission allowances which they can either use or trade with other companies. If a company exceeds its emissions cap, it can purchase additional allowances from other companies that have surplus allowances. A market stability reserve (MSR) was established in 2019 to contribute to reducing the annual emission cap. This market mechanism ensure that the surplus of quotas is reduced through removing available quotas and place them in the MSR when the surplus exceeds a certain value. From 2023, the surplus of quotas is permanently removed if the number of quotas in the MSR exceeds the previous year's auction volume (European Commission, n.d.-b).

According to Thema, reduced emissions in sectors covered by EU ETS leads to reduced prices and increased surplus of quotas. This will increase the probability of quotas being permanently removed and a cut in the emission cap (Thema Conculting Group, 2013, p.2). When analyzing the effect of electrification projects on the NCS it is therefore necessary to consider the dynamics of the carbon market.

3.4.4. Politics and debate

It is agreed that the NCS must be electrified for Norway to reach its climate goals within 2030. However, the topic has created a heated debate in Norway over the last few years and there are still disagreements about whether using power from shore is a good solution or not. The debate has arisen mostly due to uncertainties about the measure's global climate effect and the social cost it leads to.

Today, there are still many uncertainties surrounding the global effect of electrification. The Norwegian government presented a statement from the Storting in 2021 about the value creation from Norwegian energy resources. The message stated that electrification with power from shore reduces the emissions from the NCS, but that the effects on the emissions in short and long term on a global level are more uncertain due to the European quota system for GHG emissions (Meld.St.36. (2020-2021), p.155). Even though several researchers have shown skepticism towards the measure's contribution to reducing global emissions, the recent studies done by Rystad and Thema indicate that the global effect may be more positive than previously expected.

Electrification with PFS makes up a significant part of the expected increase in power demand in Norway throughout the next years. Statnett estimates that the normal annual power consumption in Norway will increase from 140 TWh in 2022 to 164 TWh in 2027. The energy balance is estimated to go from a surplus of approximately 18 TWh in 2022 to a deficit of 2 TWh in 2027 (Statnett, 2022, p.11). Electrification with PFS will contribute to increased power prices and pressure on the Norwegian power grid system. Some researchers suggest that it would be more beneficial to use the power in other sectors in Norway or export it.

4. Economic Analyses

Several PFS projects being considered for existing offshore facilities require investments in the range of four to five billion kroner. The expenses for modifications vary based on the specific facility and the extent of equipment replacement required. The cost is higher when replacing direct-drive equipment compared to replacing only the gas turbines that generate electricity. To minimize costs, it makes sense to recover the heat from the turbine exhaust to meet the facility's heating needs, especially if some turbine operation is still required. The size, existing equipment, installation type, distance from shore, and weight capacity are all factors that determine the scale and cost PFS conversions (NPD, 2020, p.20-21).

In any economic analysis, it is crucial to use appropriate financial metrics and tools to evaluate the feasibility and profitability of a project. These metrics can provide valuable insights into the potential risks and benefits of a project, helping decision-makers make informed choices about whether to invest in it or not. (The Investopedia Team, 2023).

4.1. CapEx, OpEx & ABEX

Capital expenditures (CapEx), are funds that companies use to acquire, upgrade, and maintain physical assets like property, plants, buildings, technology, or equipment. CapEx is usually employed by companies to undertake new projects or investments, such as purchasing equipment or constructing new facilities. These fixed assets help companies expand their operations or add future economic benefits to their operations. In summary, CapEx is a type of financial investment made by companies to improve or increase their physical assets and capabilities (Fernando, 2023b). Operational expenses (OpEx) on the other hand, should not be confused with CapEx. Operating expenses are the costs that companies have to pay regularly to keep their business running. These expenses are different from capital expenditures because they are not long-term investments. Unlike capital expenditures, operating expenses can be fully deducted from a company's taxes in the same year that the expenses occur (Ross, 2023).

The cost that a company must pay to properly shut down and dispose of an asset that is no longer needed, is called Abandonment expenditure (ABEX). In other word, ABEX is the term used to describe the costs that a company incurs when it decides to discontinue the use of a physical asset or facility and must undertake actions such as closure, decommissioning, removal, or abandonment of the asset (Law Insider, n.d).

4.2. NPV, IRR & Payback Period

When evaluating potential investments, financial analysts often use two key metrics: net present value (NPV) and internal rate of return (IRR). NPV calculates the difference between the present value of incoming and outgoing cash flows over a specific period (Gallant, 2022), while IRR estimates the potential profitability of an investment by determining the discount rate that would make the NPV of all cash flows equal zero in a discounted cash flow analysis (Fernando, 2023a).

In essence, NPV and IRR are both important tools for determining the financial viability of an investment opportunity. By assessing the present value of future cash flows and considering the time value of money, analysts can gain a better understanding of the potential risks and rewards associated with a particular investment. The formulas for both NPV and IRR are presented under:

Formula for NPV is (Gallant, 2022):

$$NPV = \sum_{t=0}^{n} \frac{Rt}{(1+i)^t} \tag{1}$$

Where:

- Rt = Net cash inflow-outflows during a single period, t
- I = Discount rate or return that could be earned in alternative investments
- t = Number of timer periods

Formula for IRR is (Fernando, 2023a):

$$0 = NPV = \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} - C_0 \tag{2}$$

Where:

- C_t = Net cash inflow during the period t
- C_0 = Total initial investment costs
- IRR = The internal rate of return
- T = The number of time periods

Calculating the return on investment (ROI) is a step for investors and corporations when evaluating potential investments. One widely used metric for this purpose is the payback period, which calculates the time required to recoup the initial investment costs associated with a project or investment (Ross et al., 2018, p.200). The payback period is a valuable tool in investment decision-making, especially in cases where time is of the essence, and swift decisions must be made. By determining the amount of time it will take to recover the initial investment costs, investors can better assess the risks and rewards of a particular investment opportunity. To calculate the payback period, a simple formula is used, which considers the initial investment costs and the expected future cash flows from the investment. The formula for Payback period is (Kagan, 2023):

$$Payback\ periode = \frac{Cost\ of\ Investment}{Average\ Annual\ Cash\ Flow} \tag{3}$$

4.3. Abatement cost

The Abatement cost is expressed as a net socio-economic cost per ton of CO_2 reduced as a result of a specific measure. It is calculated by quantifying the monetary value of various impacts associated with implementing measures to reduce emissions and dividing it by the amount of emissions reduced. Both the direct economic effects and the discounted benefits of emission reductions are taken into account. Essentially, abatement cost is a simplified way of evaluating the costs and benefits of emission reduction measures. The lower the abatement cost, the more cost effective the measure is considered to be. (NPD, 2020, p.32). The analysis is done before tax and does not consider the company's capital costs or other business financial conditions. It is assumed that the expected quota price and tax level express the societal value of emission reductions. In this case, an abatement cost that is lower than the sum of these would indicate that the project is economically profitable for society (cost effective). The formula for calculating abatement cost, as provided by the Norwegian Petroleum Directorate, is presented below (NPD, 2020, p.60):

$$\frac{NOK}{Ton\ Reduced\ CO2} = \frac{NPV(CAPEX + OPEX)_{PFS} - NPV(CAPEX + OPEX)_{APS}}{NPV(CO2\ Emissions)_{APS} - NPV(CO2\ Emissions)_{PFS}} \tag{4}$$

Where:

- NPV = Net Present Value, PFS = Power from shore, APS = Alternative Power Source

4.4. Tax & Depreciation

In Norway, all activities related to extracting petroleum from the NCS are subject to taxation. The taxation is based on the net income generated, at a marginal tax rate of 78%. This tax rate consists of two components: the ordinary corporate income tax rate of 22%, and an additional special tax rate of 56%. While all income generated from upstream petroleum activities is subject to the ordinary 22% corporate income tax rate, only income generated from offshore production and pipeline transportation of petroleum from the NCS falls under the additional 56% special tax rate. Under the new tax system implemented in 2022, the calculation of taxes on upstream petroleum activities in Norway now involves two steps. The first step involves calculating taxes on the ordinary 22% tax base. In the second step, the resulting tax amount is deducted from the special tax base, and a technical special tax rate of 71.8% is applied to ensure that the total effective tax rate remains at 78% (Pwc, 2023b)

Depreciation expense of a company results in a reduction of the earnings subject to taxation, leading to a decrease in the amount of taxes to be paid. If the depreciation expense is higher, the taxable income reduces further, resulting in a reduced tax liability for the company. Depreciation rates vary depending on the asset group. The table taken from PWC tax summaries in Norway shows the different asset groups (maximum rates) (Pwc, 2023a):

Table 1: Different depreciation rates in % (Pwc, 2023a)

Asset	Depreciation rate (%)
Office equipment machines, etc. (asset group a)	30
Acquired goodwill/business value (asset group b)	20
Trucks, lorries, buses, taxis, vehicles for persons with disabilities (asset group c)	24/30 (1)
Machinery, cars, tractors, instruments, fixtures and furniture, etc. (asset group d)	20
Ships, vessels, offshore rigs, etc. (asset group e)	14
Aircraft, helicopters (asset group f)	12
Plant for transmission and distribution of electric power and electronic equipment in a power company (asset group g)	5
Buildings and construction, hotels, hostels, inns, etc. (asset group h)	4/6/10/20 (2)
Office buildings (asset group i)	2
Fixed technical installations in buildings (e.g. heating, cooling and freezing installations, electrical installation, sanitary installations, elevators). (aset group j)	10

5. Case Study Description & Data

This chapter provides information about Vår Energi's electrification project undertaken as a case study and outlines its objectives and necessary data required to conduct various analyses. The case study examines the economic and environmental aspects of the project. Additionally, chapter 5.5 named "Development of Models," provides an overview of how the Excel models were set up to address the research question.

The objective of this chapter is to provide an explanation of the case study, including assumptions and limitations, in a clear and concise manner. This will make it easier to understand the project and its analyses.

5.1. Balder/Grane Electrification Project

This section provides an overview of the case study conducted in this master's thesis, presenting fundamental details and information.

5.1.1. Project Description

The Balder-Grane electrification (BGE) project aims to select a solution for electrifying the facilities in the Balder and Grane licenses. The purpose is to reduce CO_2 emissions and meet Vår Energi's emissions reduction targets of 50% by 2030. Vår Energi, as Balder field Operator, is heading the development, with Equinor as a participant being the Operator of the Grane field. The objective of the project is to reduce both CO_2 and NOx-emissions on the Jotun FPSO, Ringhorne and Grane facilities using power from shore to reach company sustainability goals. This master thesis has its focus on CO_2 emissions, hence NOx values in this case study will be excluded.

Vår Energi and the BGE project have been granted a connection of up to 140 MW at the Statnett Gismarvik Substation. This station is planned to be built as part of the Blåfalli project to deliver up to 500 MW power to the new industrial area at Haugalandet. The proposed solution for the BGE project has an onshore Point of Connection (POC) located at Gismarvik. This will be connected to a jacket hub through a cable spanning 196 kilometers, as shown in Figure 13. The project has a Final Investment Decision (FID) scheduled for 2026. Its objective is to develop an area solution in partnership with the Grane license, and the project timeline is aligned with theirs. The BGE project is planned to have its start-up in the fourth quarter of 2029.

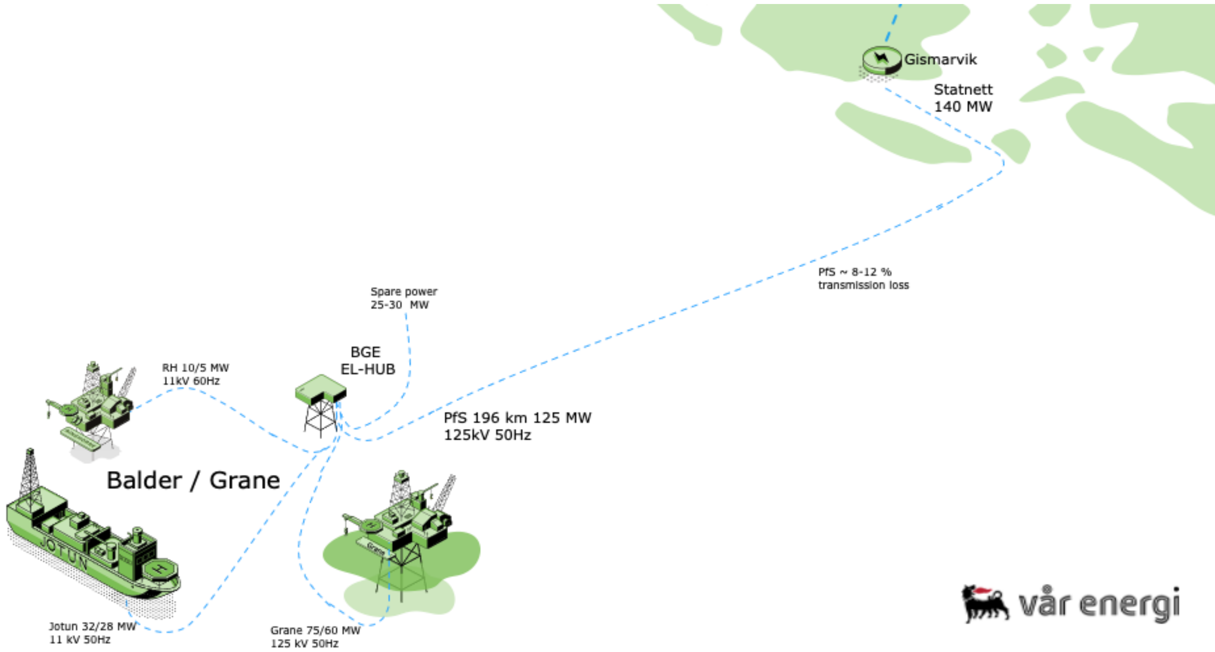


Figure 13: BGE Base Case Visualization

The Balder X project involves a significant redevelopment of the Jotun and Ringhorne fields in the North Sea. As part of the redevelopment, the Jotun FPSO, a Floating Production Storage and Offloading facility, will undergo upgrades and life extension to continue producing crude oil and gas at sea. Currently, the Jotun FPSO is being upgraded to enhance its capabilities (Offshore Technology, 2020).

Once the upgrades are complete, the Jotun FPSO will complement operations starting in 2024, and from 2029/2030, it will take over economic wells when Balder is brought ashore. The crude oil produced in the area will then be stored in tanks and transported directly to tankers for shipment (Vår Energi, 2020). However, in this case, the gas extracted will primarily be transferred onshore through pipelines instead of being used as fuel for gas turbines (if electrification) (Kawasaki Kisen Kaisha LTD, n.d.). Equinor and Vår Energi have a combined ownership of approximately 65% in the Grane field, which is part of the BGE project located east of Balder. Vår Energi specifically holds a 90% ownership in Balder. (Norsk Petroleum, n.d.-a). The objective of this case study is to examine the various offshore facilities in relation to the BGE project.

5.1.2. The Zero Alternative & Base Case

In this master thesis, two scenarios will be compared and evaluated in order to analyze the costs and benefits of the BGE project. The first scenario, referred to as "*The Zero Alternative"*, describes a situation in which no action is taken offshore, and gas turbines generate power and heat for the offshore facilities. This solution is not aligned with Vår Energi´s strategic beliefs and goals as it leads to large quantities of GHG emissions. Therefore, it is clear that the zero alternative is not a viable solution and alternative approaches must be explored. The second scenario, *"The Base Case*", involves electrification and how it will be implemented. The strategic approach adopted for electrification plays a crucial role in determining the extent to which CO2 emissions can be reduced and the quantity of gas that can be exported to Europe. Therefore, it is critical to evaluate the available strategic approaches and choose one that is aligned with Vår Energi´s strategic beliefs and goals to ensure successful implementation of the electrification project. Figure 16 in chapter 5.5 "Model development" shows a simplified process chart of the two scenarios.

Chapter 3.3 describes some possibilities to supply power and heat to offshore installations. There are different electrification concepts and strategies that one could discuss. In this case study of BGE project, it is considered that both Ringhorne and Grane facilities will be fully electrified while Jotun A will be operated in a hybrid mode. In hybrid power generation, one of the gas turbines is required to run at 30% load in combination with power from shore. Table 2 presents the minimum power needs of each facility in the Zero Alternative and Base Case scenarios. This data has been gained from diverse sources, including meetings and discussions with Vår Energi, as well as internal project documents, which have contributed valuable insights into the project's requirements. In the Zero alternative scenario, a minimum of 63 MW power is required from turbines. However, in the base case, only 6 MW power is required for heating generation (turbine 30% load), while the remaining power needs will be sourced from shore. This data will be used to carry out further calculations and analyses of the electrification project. However, it is important to note that the effect of gas fired heaters has not been included in this case study.

Table 2: Shows assumed power required from turbines for each facility.

Facilities	The Zero Alternative	Base Case
Jotun A – FPSO	28 MW	0 MW
Jotun A-Heating generation	-	6 MW
Ringhorne	5 MW	0 MW
Grane	30 MW	0 MW

It has also been assumed that the power demand from each offshore facility will remain constant over the project's lifetime during the analysis. Further details on the utilization of this data will be provided in the subsequent chapters.

5.2. Economic data Considerations & Assumptions

The BGE project's FID is set for 2026, hence the economic analyses will consider investments from 2026 and project start-up in 2030. For the economic analyses of the project, various financial metrics such as Net Present Value (NPV), Internal Rate of Return (IRR), payback period, and abatement cost will be calculated. To achieve credible economic results, there will be considered various factors that influence the results. These factors are such as Capital Expenditure (CapEx), Operating Expenditure (OpEx), Abandonment Expenditure (ABEX), revenue, cost savings, inflation, and other relevant considerations. These financial metrics will serve as critical indicators of the project's economic viability and will form the basis of the project's financial evaluation. The green outline in figure 14 shows what this thesis has considered, the figure also shows a projects timeline from idea to termination.

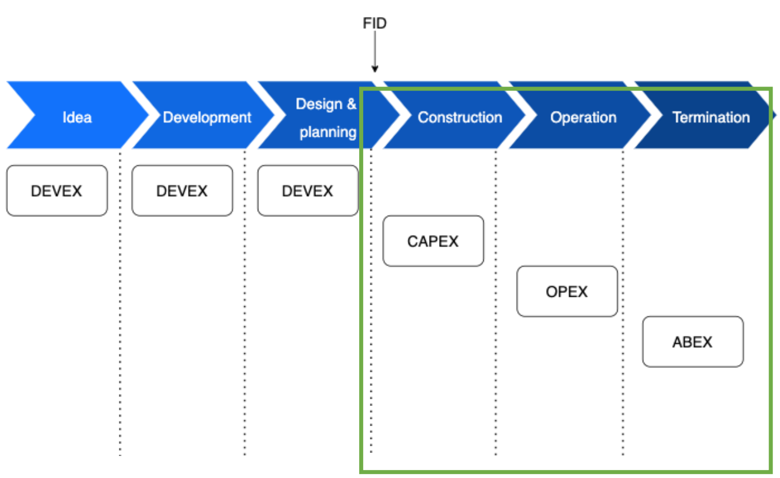


Figure 14: Shows what the economic analyses have included in the calculations.

5.2.1. Case Study CapEx, OpEx & ABEX

This master thesis is based on certain assumptions regarding CapEx, OpEx, and ABEX due to the limited data available and time constraints. The data provided by Vår Energi has been utilized to make additional assumptions to fill in the gaps on missing data for Grane, which is operated by Equinor. While the accuracy of these assumptions may be improved, conversations have been held with Vår Energi to ensure that the data is not too far off. Thus, the thesis relies on assumptions to some extent to compensate for missing data on Grane.

It should be noted that the given data has been simplified to a certain extent due to the complexity of the subject matter, and as a result, some assumptions have been made in order to provide a complete analysis. CapEx, OpEx, and ABEX are crucial input values for conducting economic analyses. It is assumed that Grane has the same CapEx, OpEx, and ABEX as Balder, resulting in a multiplication factor of 2x for those values. However, when it comes to modifications specific to Grane, it is assumed that the cost would be 10 times higher than the modifications for Jotun and Ringhorne. Following tables will show cost estimations, simplification and assumptions done on the input data used in the analyses:

Table 3: CapEx cost estimation

CAPEX COST ESTIMATE - TOPSIDE/JACKET			
Onshore development	**MNOK**	**-**	**1 000**
Offshore facilities:			
Topsides/jacket	MNOK	-	3 892
Subsea Power Cable	MNOK	-	3 368
Jotun modifications	MNOK	-	112
Ringhorne modifications	MNOK	-	70
Grane modifications	MNOK	-	1 820
Offshore logistics	MNOK	-	90
Sum offshore facilities	**MNOK**	**-**	**9 352**
Marine installations	**MNOK**	**-**	**400**
Sum CAPEX estimate	**MNOK**	**-**	**10 752**

Table 4: OpEx reduction cost estimation

OPEX **REDUCED** COST ESTIMATE - TOPSIDE/JACKET					
		2030	2031	2032	2033
Reduced manning offshore Jotun	MNOK/yr	3	3	3	3
Reduced manning offshore RH	MNOK/yr	5	5	5	5
Reduced manning offshore Grane	MNOK/yr	3	3	3	3
Sum reduced manning offshore cost	**MNOK/yr**	**11**	**11**	**11**	**11**
Logistics - Jotun	MNOK/yr	1	1	1	1
Logistics - RH	MNOK/yr	2	2	2	2
Logistics - Grane	MNOK/yr	2	2	2	2
Sum reduced Logistics cost	**MNOK/yr**	**5**	**5**	**5**	**5**
Turbine maintenance General Jotun	MNOK/yr	1	1	1	1
Turbine maintenance General RH	MNOK/yr	2	2	2	2
Turbine maintenance General Grane	MNOK/yr	2	2	2	2
Turbine maintenance change out Jotun	MNOK/4yr	0	0	0	25
Turbine maintenance change out RH	MNOK/4yr	15	0	15	0
Turbine maintenance change out Grane	MNOK/4yr	15	0	15	0
Sum reduced Turbine maintenance cost	**MNOK/yr**	**35**	**5**	**35**	**30**
External fibre contract	**MNOK/yr**	**16**	**16**	**16**	**16**
Sum OPEX reduced cost estimate	**MNOK/yr**	**67**	**37**	**67**	**62**

Table 5: OpEx increased cost estimation

OPEX **INCREASED** COST ESTIMATE - TOPSIDE/JACKET		
Manning offshore - Jotun A & RH	MNOK/yr	-2
Manning offshore - Grane	MNOK/yr	-2
Manning offshore hub	MNOK/yr	-4
Manning onshore	MNOK/yr	-16
Sum manning increased cost	**MNOK/yr**	**-24**
Power from shore service	MNOK/yr	-2
Onshore facilties Maintenance	MNOK/yr	-2
Topsides facilties Maintenance	MNOK/yr	-6
Subsea facilties Maintenance	MNOK/yr	-3
Subsea power cable Maintenance	MNOK/yr	-4
Sum Service/Maintenance increased cost	**MNOK/yr**	**-34**
Logistics - Jotun	MNOK/yr	-1
Logistics - Grane	MNOK/yr	-1
Logistics - Offshore hub	MNOK/yr	-20
Sum logistics increased cost	**MNOK/yr**	**-22**
Sum OPEX increased cost estimate	**MNOK/yr**	**-80**

Table 6: ABEX cost estimation

ABEX COST ESTIMATE - TOPSIDE/JACKET				
	Qty	Rate		Estimate (MNOK)
Owner's cost			**MNOK**	**-80,0**
Contractor Management & Engineering			**MNOK**	**-82,0**
Topsides / Jacket removal				
Topsides deconstruction, lifting and removal	1	145,83	MNOK	-145,8
Jacket lifting & removal	1	117,25	MNOK	-117,3
Sum Topsides / Jacket removal			**MNOK**	**-526,2**
Subsea removal				
Rock dumping of ends	10 000	0,0009	MNOK	-9,0
Post removal survey	4	1	MNOK	-4,0
Disposal/Scrapping	6000	0,003	MNOK	-18,0
Sum subsea removal			**MNOK**	**-62,0**
Sub total			**MNOK**	**-750,2**
Contingency	**30%**		**MNOK**	**-225,0**
Total ABEX Estimate			**MNOK**	**-975,2**

5.2.2. Discount Rate, Inflation & Depreciation

The discount rate is an important factor used in analyses to determine the net present value (NPV) and the abatement cost of a project. Typically, the evaluation of petroleum investments associated with the government's review of development plans employs a discount rate of 7% (NPD, 2020, p.60). However, the Norges vassdrags- og energidirektorat (NVE) indicates that the Ministries of Finance prescribe a 4% interest rate for computing socio-economic analyses spanning up to 40 years (NVE, 2022). This case study will incorporate these two different discount rates, 4% and 7%, to analyze the BGE project. The analyses will assess the net present value (NPV) and abatement cost of the project using both discount rates, which will allow for a comprehensive understanding of the financial implications of the project under different scenarios. The findings and discussion of these analyses' results will be presented in Chapter 6.

Inflation rates will also be used in this case study. The Norwegian Bank's goal of achieving an annual increase in consumer prices that is approximately 2 percent over time will be used to adjust inflation in the economic analysis (Norges Bank, 2020). Furthermore, tax and depreciation rates will be considered. Chapter 3.5.4 provides a theoretical overview about tax and depreciation, and table 1 illustrates the diverse depreciation rates of various assets. For this study, the “asset group g" with a depreciation rate of 5% will be utilized.

The economic analyses have been done with some simplified market prognoses for the years 2030 to 2050. This includes gas, power, and CO_2 prices, which are all significant factors that can impact the economic outcome. Chapter 5.4 will go deeper into these market assumptions.

5.3. CO_2 Emission Calculation data - Considerations & Assumptions

To carry out a thorough economic and environmental impact analysis of a project, it is crucial to gather information and perform calculations regarding the overall CO_2 emissions and gas fuel consumption of both the Zero alternative and Base case. These values are essential in determining the various financial metrics such as NPV, IRR, and payback periods, as well as calculating the global CO_2 emissions. Chapter 5.5, "Development of Models", provides insight on how the calculation will be done and table 7 includes several data assumptions required to perform calculations and achieve the desired CO_2 and fuel gas values of the two scenarios. The calculations are presented in appendix 1.1a & 1.1b, which shows the calculated data that will be utilized in the economic and environmental impact analyses. During the calculation process, it has been crucial to always maintain correct units. Dividing and multiplying various units together to get the desired values has been a big part of these calculations, therefore, ensuring accurate unit conversions is of utmost importance.

Table 7: Data used for calculation CO2 Emission and fuel gas consumption.

Specification	Value	Unit	Source/Assumption
Fuel gas - emission of 1 Sm3 gas - wet	2,34	ton CO2/1000 Sm3	(SSB, 2022b, p.1)
Fuel gas - emission of 1 Sm3 gas - dry	1,99	ton CO2/1000 Sm3	(SSB, 2022b, p.1)
Turbine efficiency - NG turbines on the NCS	30%		(Konkraft, 2021, p.18)
Turbine efficiency - 1X30% load	22%		(Cuviella-Suarez et al., 2019, p.724)
Hours in operation	8 760,00	Hours/yr	Assumption
Availability of power turbines	100%		Assumption
1 boe	1 638,00	kWh	(Rystad Energy, 2023, p.10-Appendix)
1 kWh	3,60	MJ	(Norsk Petroleum, n.d.-b).
1 Sm3	40,00	MJ	(Norsk Petroleum, n.d.-b).
1 Sm3	11,11	kWh	Calculated: 40/3,6
Average The efficiency in a gas power plant	49%		(Rystad Energy, 2023, p.10-Appendix)

Konkraft's 2021 status report “Framtidens Energinæring På Norsk Sokkel” states that the turbine efficiency on the NCS ranges between 25-35% depending on the type, age, and operational conditions (Konkraft, 2021, p.18). For this case study, an average turbine efficiency of 30% will be used, but a lower value of 22% will also be used for turbines with a 30% load in the Base Case scenario. The 22% is based on Figure 5, presented in Chapter 3.3.1, which indicates the assumed turbine efficiency based on load.

It is important to make a clear distinction between wet and dry gas values in this case study. Wet gas value, which is gas from the continental shelf, will be used to calculate CO_2 emissions for the Zero alternative scenario. On the other hand, dry gas is utilized in calculations and plays a significant role in analyzing the global CO2 emissions. The information and calculations regarding wet and dry gas have been obtained from SSB (2022b) and Rystad Energy (2023). Accuracy and reliability in the analyses have been ensured by relying upon these sources. Additionally, careful selection of other data used in this analysis has been undertaken to maintain a certain level of accuracy and reliability. In accordance with the data presented in table 7, it is assumed that one barrel of oil equivalent containing natural gas provides 1638 kWh of energy (Rystad Energy, 2023, p.10-Appendix).

5.4. Market Assumptions 2030-2050

In this chapter, the market assumptions made in this case study are examined, focusing specifically on the estimated values for power, gas, and CO2 prices throughout the projected lifetime of the project, spanning from 2030 to 2050. The economic results of the study rely on the assumed and estimated values. Recognizing the significance of accurate assumptions, the master thesis incorporates data from reliable sources such as Equinor, NVE, and the Government of Norway to conduct simplified price prognoses, ensuring the credibility and accuracy of the analysis. Note that an exchange rate from Euro to NOK of 9.9 is used.

5.4.1. Power Price

In order to conduct simplified price prognoses for power prices from 2030 to 2050, data from NVE's "Langsiktig Kraftmarkedsanalyse 2021-2040" report was utilized (NVE, 2021, p.59). The estimated future power prices in various price areas in Norway are presented in the table 8 below. Statnett's substation that are planned to provide power to Balder and Grane is located in Gismarvik, belonging to the NO2 region. In the economic analyses, an average power price of 526.67 NOK/MWh will be utilized as a representative value over the entire lifetime of the project. The price data table is visualized as a scatter plot in Appendix 1.2.

Table 8: Estimated average power price for period 2030-2050.

	LOW			BASE			HIGH		
	2025	2030	2040	2025	2030	2040	2025	2030	2040
Norway	41	40	38	50	52	50	60	67	63
Sweden	41	39	36	49	50	48	60	64	60
Finland	40	36	37	48	47	49	57	59	60
Denmark	46	43	40	55	55	53	67	70	68
Germany	47	44	40	57	56	54	70	73	70
NO1	44	43	40	53	55	53	64	71	67
NO2	44	42	38	53	54	51	64	70	65
NO3	40	39	38	49	49	50	58	63	63
NO4	31	34	33	39	44	43	46	57	54
NO5	43	42	39	53	54	52	64	69	65

Price in øre/kWh. EUR-NOK: 9,9

	LOW	BASE	HIGH
	2025-2040	**2025-2040**	2025-2040
Norway	39,67	**50,67**	63,33
NO2	41,33	**52,67**	66,33

Price in øre/kWh. EUR-NOK: 9,9

Average NO2 power price -Used in NPV	
52,67	øre/Kwh
526,67	**NOK/MWh**

5.4.2. Gas Price

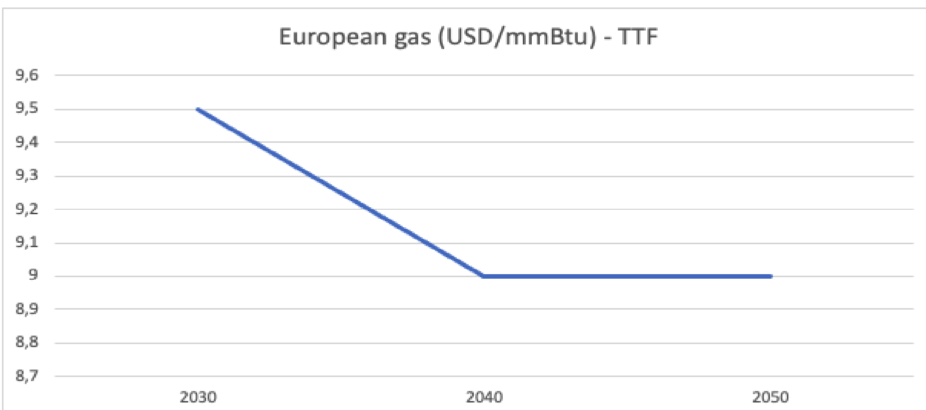
Gas prices were estimated using data from Equinor's third-quarter 2022 Financial statements and review report (Equinor, 2022, p.25). The calculated average gas price of 3.44 NOK/Sm3 corresponds to the TTF (Title Transfer Facility) gas price. This value will be utilized as the representative gas price for the entire lifetime of the project. The simplified calculations leading to this average TTF gas price are presented in Table 9.

Table 9: Estimated average gas price 2030-2050

	2030	2040	2050	
European gas (USD/mmBtu) - TTF	9,5	9	9	
mmBtu	26,37	26,37	26,37	Sm3
European gas - TTF	94,05	89,10	89,10	NOK/mmBtu
European gas - TTF	3,57	3,38	3,38	NOK/Sm3

Average 2030-2050	**3,44 NOK/Sm3**

USD/NOK -Used in calcualtions		
	USD/NOK	9,9



5.4.3. CO_2 Price

The Ministry of Finance has established regulations on how greenhouse gas emissions should be considered in socio-economic analyses of government measures. According to these regulations, the analyses should utilize annually updated carbon price paths from the Ministry of Finance. The government's website provides information on the specific price path for the petroleum sector that should be used in analyses conducted in 2023 (Regjeringen, 2022a). Figure 15 illustrates how the average CO_2 price was calculated for this case study, where the red box indicates the calculated period, resulting in an average of 2230 NOK/ton CO_2.

The data sheet used to calculate the average CO_2 price for the given period is presented in Appendix 1.3.

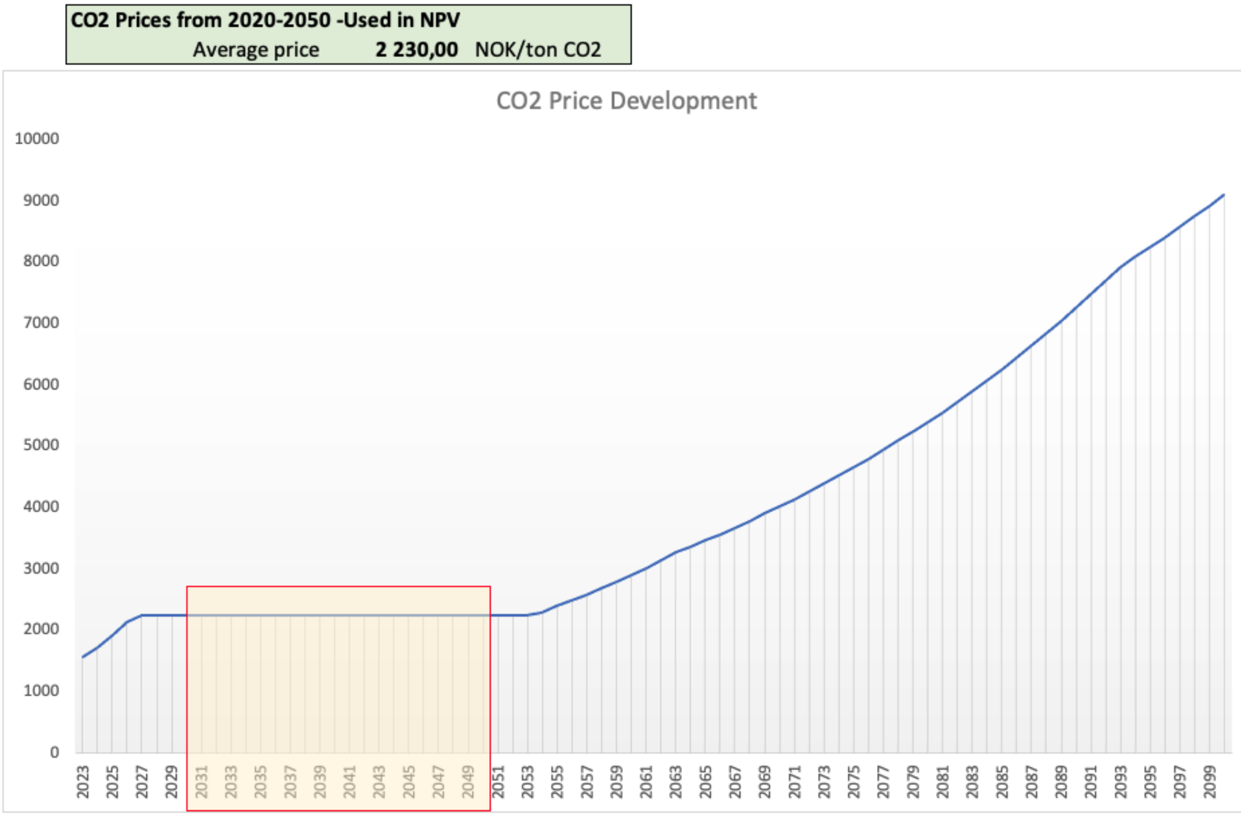


Figure 15: Estimated average CO2 price 2030-2050

5.5. Development of Models

This master thesis will provide a detailed analysis of the potential environmental and economic impacts of the BGE project. Chapter 5.3 describes the calculations and data used to estimate the levels of CO_2 emissions and fuel gas (Sm^3) associated with the two different scenarios. These calculated values are crucial for further analysis in this study.

For the economic analyses, the calculated values for total reduced CO_2 emissions, additional gas export to the EU, and required power purchases will be incorporated into the cash flow for the analyses. On the other hand, the global environmental impact analysis will rely on both the Zero Alternative and Base Case data to provide an understanding of the project's environmental impact. To get a better understanding of the two scenarios and their effects on the gas, Figure 16 below has been included.

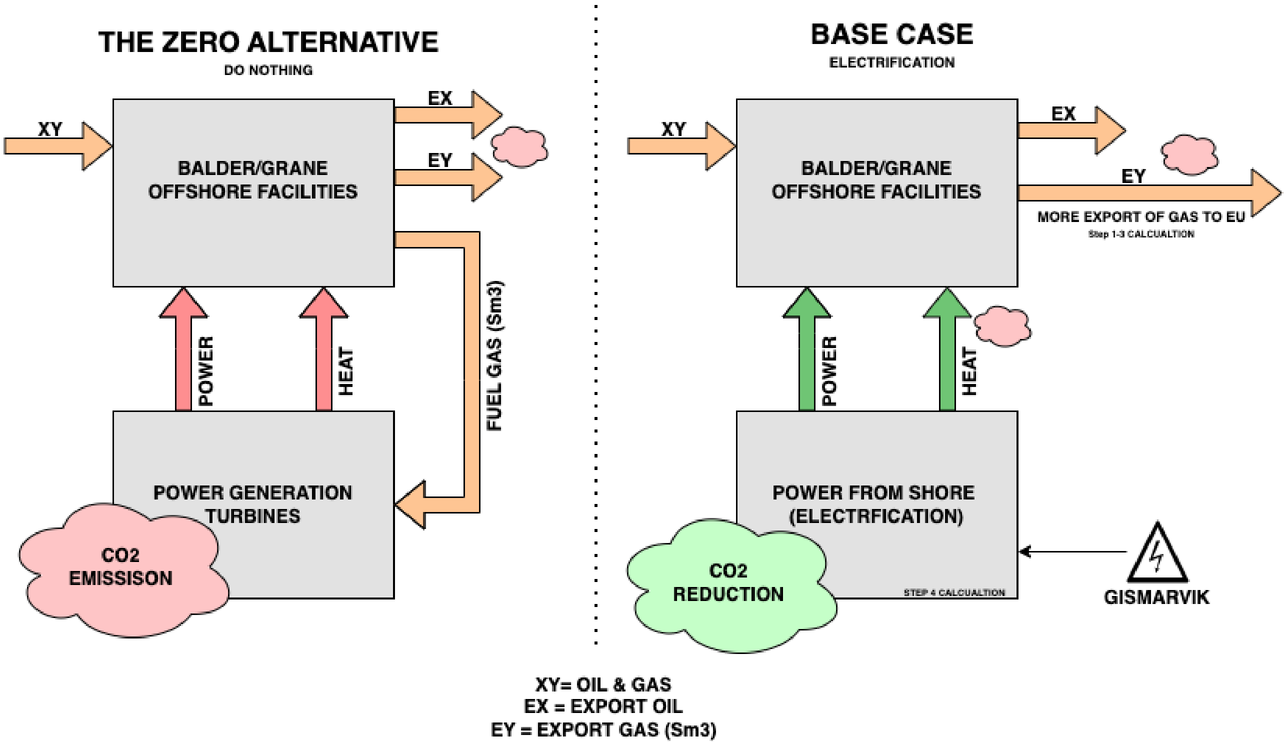


Figure 16: Simplified process chart of The Zero Alternative & Base Case scenario

Figure 16 shows that there is an increased amount of gas available for export through electrification (Base Case). It is anticipated that this gas will be sold to Europe without any issues concerning GASSCO's (or others) gas pipeline capacity (Gassco, n.d.).

In addition to performing economic analyses, this master's thesis aims to calculate the environmental impacts both at the national and global level. Calculation on the global CO_2 emission involves four steps that have been inspired by the two recent studies from Rystad Energy Consulting and Thema Consulting Group. It is important to note that Rystad's study primarily focuses on the impact of increased gas supply to Europe and does not explicitly consider the power market in its analysis. Conversely, Thema's study specifically addresses the power market. By considering these two studies together, they complement each other and provide a more comprehensive understanding of the overall impact of the gas and power market.

The following paragraphs provide a description of the data and assumptions that will be used to develop and calculate steps 1 to 4 in the environmental impact analysis of the global CO_2 emission. The first three steps draw inspiration from the Rystad study, while step 4 is based on the Thema study.

Step 1 – Increased EU consumption due to market effect

According to Rystad's analysis, 77% of the additional gas supply from Norway is expected to replace other existing gas production, while the remaining 23% is anticipated to be absorbed through higher demand (Rystad Energy, 2023, p.17). In simpler terms, Increased consumption due to market effect of increased supply of gas to Europe. This mechanism applies to new Norwegian pipeline gas delivered to the European market, which also affects the global LNG market.

Step 2 – Demand substitution due to increased gas from Step 1

According to Rystad Energy's analysis (Rystad Energy, 2023, p.20), approximately 70% of the energy displaced by the increased gas supply is estimated to come from coal, while the remaining 30% is sourced from emission-free alternatives. The availability of more gas (23%) at lower prices will lead to a partial substitution of coal consumption in countries that import liquefied natural gas (LNG). To calculate the impact, the study assumes an average turbine efficiency of 49% for gas power plants and employs a gas-to-energy conversion factor of 1638 kWh/boe. Additionally, the study assumes a coal power CO2 emission factor of 0.86 kg CO2/kWh (Rystad Energy, 2023, p.10-Appendix). The study focuses on the time horizon of 2030, and the relevant assumptions are highlighted in yellow in Table 10.

However, to account for the period from 2030 to 2050, this master thesis incorporates additional assumptions regarding the percentage of gas replacing coal power. These assumptions were derived by estimating the expected total energy supply from 2030 to 2050 based on data from the International Energy Agency (IEA, 2021) and Rystad Energy. The grey highlighted area in the table represents the assumptions made in this thesis, while the yellow highlights correspond to the data used in the Rystad Energy study.

Table 10: Data used in step 3 Calculations.

	2030	2035	2040	2045	2050
Increased share of gas replacing coal power	70%	65%	60%	55%	50%
Increased share of gas replacing renewable power	30%	35%	40%	45%	50%
Assumed gas turbine efficiency (gas power plant)	49%	49%	49%	49%	49%
Energy content in 1 boe gas to power	1 638	1 638	1 638	1 638	1 638
CO2 Emission factor coal power	0,86	0,86	0,86	0,86	0,86

Step 3 – Supply substitution due to increased gas from Step 1

The surplus gas from Norway will primarily be transported to Europe through pipelines, displacing emissions from 0.77 boe (77%) of LNG, as described in Step 1. The displaced LNG is assumed to originate from the USA, as the Rystad report identifies the USA as a long-term marginal supplier of gas to Europe (Rystad Energy, 2023, p.22). The gas production that replaces other energy sources, as mentioned in Step 1, is assumed to substitute LNG imports from the USA. Notably, the upstream, midstream, and methane intensities associated with the USA's LNG production are significantly higher than those of Norwegian gas production. This difference in emission intensity between Norwegian gas production and USA's LNG production ensures a reduction in emissions. The relevant emission parameters utilized for the calculations are summarized in Table 11.

Table 11: Data used in step 3 Calculations.

Share of increased gas supply to Europe displacing LNG from the USA	77%	
Avoided CO2 emissions from LNG gas from the USA		
Upstream intensity (LNG USA)	16,0	kg CO2/boe
Midstream intensity (LNG USA)	65,0	kg CO2/boe
Methane intensity (LNG USA)	27,0	kg CO2/boe
Upstream Intensity platform electrified	0,0	kg CO2/boe
Midstream intensity	3,0	kg CO2/boe
Methane intensity	0,0	kg CO2/boe

Step 4 – Increased emissions from increased power production for platform electrification

To perform the necessary calculations, the case study relies on a study conducted by Thema Consulting. This study provides valuable information on the long-term marginal emission factors, which are the emissions associated with meeting the increased demand in the power market. When there is a short-term increase in demand for electricity, it is usually met through either higher prices or by ramping up production from existing power plants, mainly fueled by gas or coal. However, in this case, the focus is on the long-term outlook. Table 12, sourced from Thema Consulting's study, presents the Marginal Emission Factors per MWh consumption specifically for the period between 2030 and 2050 (Thema Consulting Group, 2023, p.20). These emission factors play a crucial role in accurately estimating the amount of CO2 emissions generated by various offshore facilities.

Table 12: Marginal emission factors per MWh consumption

	2030	2035	2040	2045	2050	
CO2 Emissions linked to new power generation for platform electrification	0,195	0,140	0,080	0,045	0,010	t CO2/MWh el

6. Case Study Results & Discussion

6.1. Pre-Results – CO_2 Emission & Fuel Gas Consumption

In Chapters 2, 4 and 5 of this study, the methodology used for calculating CO_2 emissions and fuel gas consumption for each relevant facility in the case study is described. The summarized data from these calculations is presented in Table 13, sourced from the "Economic Analyses" Excel sheet (appendix 1.1b). This table provides a comparison of the final CO_2 emissions, fuel gas consumption, and power requirements between the Zero Alternative and Base Case (electrification) scenarios at a national level.

The data shows that in the Zero Alternative scenario, the turbines on Jotun A, Ringhorne, and Grane collectively emit 387,419 tons of CO_2 each production year, consume 165,564,000 standard cubic meters of fuel each year, and generate 551,880 megawatt hours of power each year. In contrast, the Base Case scenario would reduce national/local CO_2 emissions by 337,105 tons each year, save 144,062,181 standard cubic meters of fuel gas (which can be exported to Europe as extra gas), and require a total power purchase from shore of 499,320 megawatt hours each year. Appendix 1.1a and 1.1b provide the Excel sheets where the calculations leading to these results were performed. These results were then used to conduct the economic and global environmental impact analyses, the findings of which are presented in subsequent Chapters 6.2 - 6.4 of the thesis.

Table 13: CO2, Fuel Gas & Power Summary

SUMMARY - THE ZERO ALTERNATIVE & ELETRIFICATION CASE (BASE CASE)					
USED IN NPV CALCULATIONS					
The zero alternative (No electrification, CO2 Emission)			Base case - Electrification study (Reduced CO2)		
CO2 Emissions from Turbines			CO2 reduction from turbines due to electrification		
Jotun A	ton CO2/yr	172 186,56	Jotun A	ton CO2/yr	172 186,56
Ringhorne	ton CO2/yr	30 747,60	Jotun A 1x30%	ton CO2/yr	- 50 314,25
Grane	ton CO2/yr	184 485,60	Ringhorne	ton CO2/yr	30 747,60
			Grane	ton CO2/yr	184 485,60
Sum CO2 Emission	**ton CO2/yr**	**387 419,76**	**Sum CO2 reduction**	**ton CO2/yr**	**337 105,51**
Fuel gas used offshore - turbines			Saved fuel gas offshore (extra supply)		
Jotun A	Sm3/yr	73 584 000,00	Jotun A	Sm3/yr	73 584 000,00
Ringhorne	Sm3/yr	13 140 000,00	Jotun A 1x30%	Sm3/yr	- 21 501 818,18
Grane	Sm3/yr	78 840 000,00	Ringhorne	Sm3/yr	13 140 000,00
			Grane	Sm3/yr	78 840 000,00
Sum fuel gas used offshore - turbines	**Sm3/yr**	**165 564 000,00**	**Saved fuel gas offshore (extra supply)**	**Sm3/yr**	**144 062 181,82**
Power production from turbines			Power purchase from shore		
Jotun A	MWh/yr	245 280	Jotun A	MWh/yr	245 280
Ringhorne	MWh/yr	43 800	Jotun A	MWh/yr	- 52 560
Grane	MWh/yr	262 800	Ringhorne	MWh/yr	43 800
			Grane	MWh/yr	262 800
Summary			Summary		
Sum CO2 Emission	**ton CO2/yr**	**387 419,76**	**Sum CO2 reduction**	**ton CO2/yr**	**337 105,51**
Sum fuel gas used offshore - turbines	**Sm3/yr**	**165 564 000,00**	**Saved fuel gas offshore (extra supply)**	**Sm3/yr**	**144 062 181,82**
Sum power production from turbines	**MWh/yr**	**551 880**	**Sum power purchase from shore**	**MWh/yr**	**499 320**

It is important to note that several assumptions were made during these calculations, including assumptions about the turbine efficiency, power needed, availability on turbines, CO_2 emission of 1 Sm^3 gas, as well as other relevant assumptions of the offshore facilities. The accuracy of the results will be influenced by these assumptions, and it is essential to carefully consider them when interpreting the thesis's final results.

The summary data from table 13 has been used to further develop two separate Excel spreadsheets to execute the Economic and Environmental impact analyses. These excel spreadsheets allow for variable changes if the data used is incorrect. However, it is noteworthy to mention that the data used in the Excel spreadsheets has been carefully chosen and analyzed to achieve the best possible level of accuracy within the time scope of this thesis. Having presented the calculations for CO_2 emissions, fuel gas consumption, and power requirements in the Zero Alternative and Base Case scenarios, the next step is to analyze the economic implications of these findings. The next chapter, chapter 6.2, will explore the results of the economic analyses, which take into account factors such as investment costs, operational costs, and potential revenue streams for the offshore facilities.

6.2. Results - Economic Analyses

This thesis has analyzed the BGE project using discount rates of 4% and 7% to assess its net present value (NPV) and abatement cost. By doing so, the economic implications of the project have been evaluated under different scenarios to support the decision making regarding its economic viability and societal impact.

The economic analyses of the BGE project reveal its potential to generate economic value. With a discount rate of 4% before tax, the project demonstrates a positive NPV of 3493 MNOK, indicating a net economic gain. However, accounting for tax obligations, the after-tax NPV is reduced to 279 MNOK. When the discount rate is increased to 7% before tax, the NPV declines to 121 MNOK, and the after-tax NPV turns negative at -452 MNOK. These figures show that the project is not financially feasible when considering a higher discount rate. Furthermore, the project's internal rate of return (IRR) is 7.16% before tax and 4.93% after-tax (Figure 17). The calculated payback period for this case study is 126 months, which implies that it takes around 10.5 years to cover the initial investment cost.

The scatter plot in Figure 17 shows the calculated NPV results before and after tax. Although the discount rate of 7% was used, authorities commonly use a discount rate of 4%, and thus this rate has also been employed.

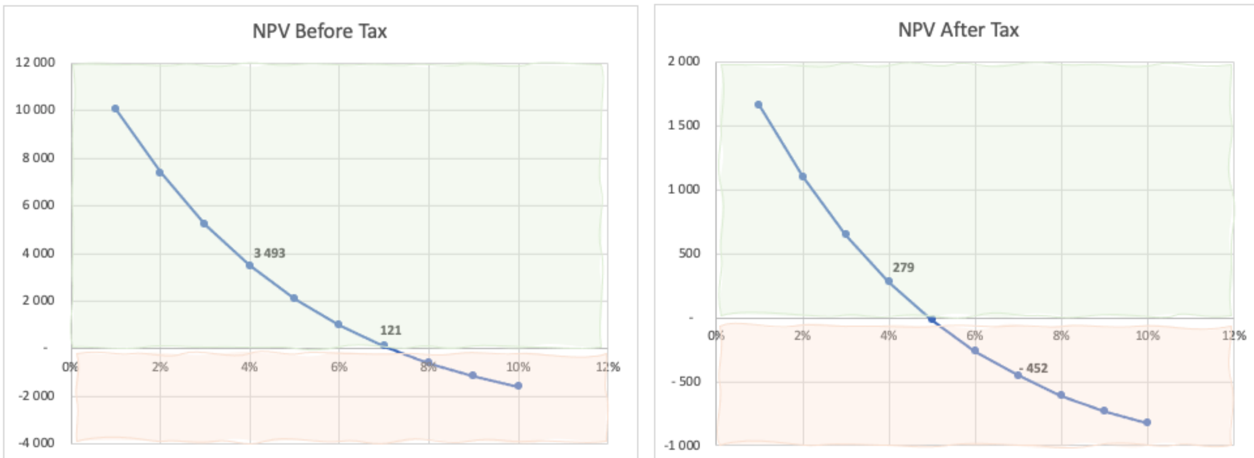


Figure 17: Scatter plot - NPV Before & After Tax (Appendix 2.1-2.4)

Sensitivity analyses are an essential tool for assessing the risk and uncertainty of a project's financial performance by evaluating the effect of changes in key input variables on the project's NPV. In this context, Figure 18 (next page) illustrates the results of such analyses performed on the NPV before tax, utilizing a discount rate of 7% and a sensitivity range of plus/minus 10%. To ensure that the most significant input variables are identified, a thorough analysis of the project's financial parameters was undertaken. As a result, the gas turbine efficiency, CapEx, CO_2 price, discount rate, electricity price, gas price, and ABEX were selected as the most critical input variables to be evaluated.

The efficiency of the gas turbine has a significant impact on the net present value of the project. This is because it directly affects the project's revenue by influencing both the reduction of CO_2 emissions and gas consumption. A high starting point value for the turbine efficiency rate (>30%) results in less CO_2 emissions when comparing the Zero Alternative (no electrification) and the Base Case (electrification). If the difference between the two scenarios is small, it will lead to lower project revenue due to lower CO_2 reduction and fuel gas consumption. On the other hand, a lower starting point for the turbine efficiency rate (<30%) in the calculations will increase revenue. This is because there is greater room for improvement, resulting in greater CO_2 reduction and fuel gas consumption. The more CO_2 emissions and fuel gas consumption in the Zero Alternative, the higher the NPV will be for the BGE project. This is because there will be more gas available for extra gas export and a greater revenue due to significant CO_2 reduction.

Furthermore, the CapEx has the second most significant impact on the NPV. This finding is not surprising, as the CapEx represents a significant portion of the project's initial investment cost. As such, a change in CapEx would significantly affect the NPV, resulting in either increased or decreased project profitability. Additionally, the CO_2 price and discount rate had a considerable impact on the NPV. A higher CO_2 price resulted in increased revenue as the project's CO_2 reduction benefits became more valuable, while a higher discount rate reduced the project's future cash flows, leading to a lower NPV. On the other hand, the electricity price, gas price, and ABEX had a less great impact on the NPV. According to the results, the impact of both ABEX and OpEx (not included in figure 18) on the profitability of the project was found to be minimal.

Figure 18 note: Dark blue = 10% increase, Light blue = -10% decrease

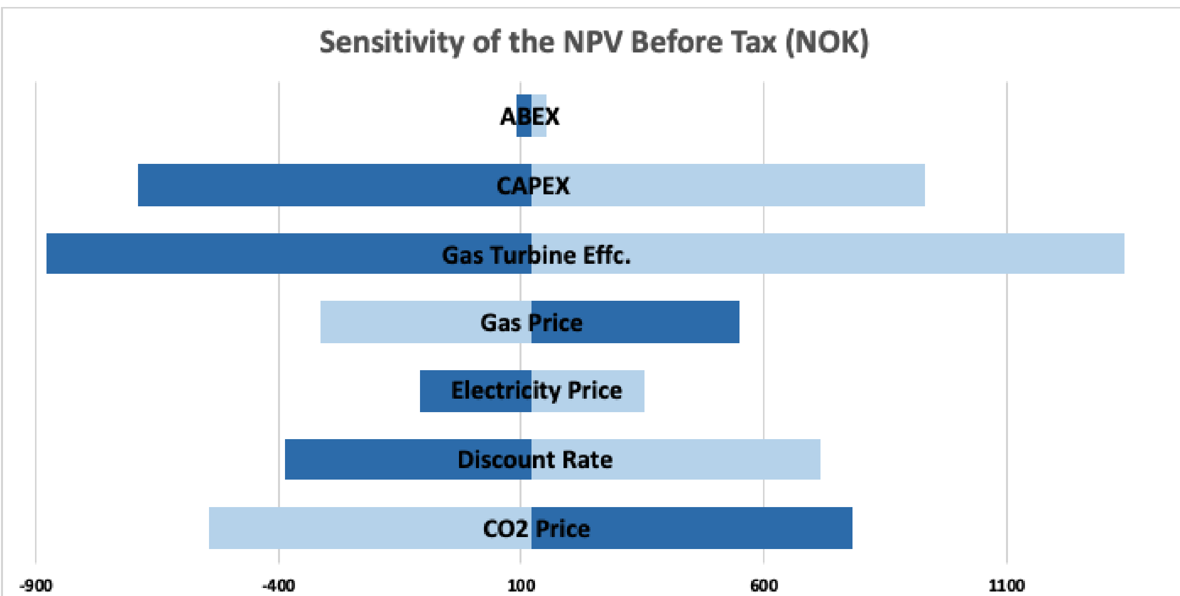


Figure 18: Tornado Diagram - NPV Sensitivity +-10% (Appendix 2.5)

6.3. Results - Environmental Impact Analysis: Global CO_2 Emissions

The objective of this study was to investigate the impact of electrifying offshore facilities. In this study, the BGE case study was examined, and the national CO_2 emission was further analyzed to determine the global CO_2 emission by implementing this electrification project. The Base case study indicates that the BGE project will lead to a reduction of 337,4105 tons of CO_2 emissions annually. This is a significant national CO_2 reduction, and it is mainly due to the substitution of gas turbines with power from shore.

Electrification projects with PFS do also have a global impact because of more available gas for export and increased demand of power in Europe. The analysis conducted in this study showed that the global CO_2 emissions reduction from the case study is more significant than the national CO_2 reduction. In 2030, the global CO_2 emissions reduction is estimated to be 350,485 tons per year, while in 2050, it is estimated to be 421,554 tons per year. These estimates are compared to the national CO_2 reduction of 337,4105 tons per year. Figure 19 illustrates the changes in CO_2 emissions, including reductions and increases, in 2030 and 2050, along with the total reduction achieved during the period.

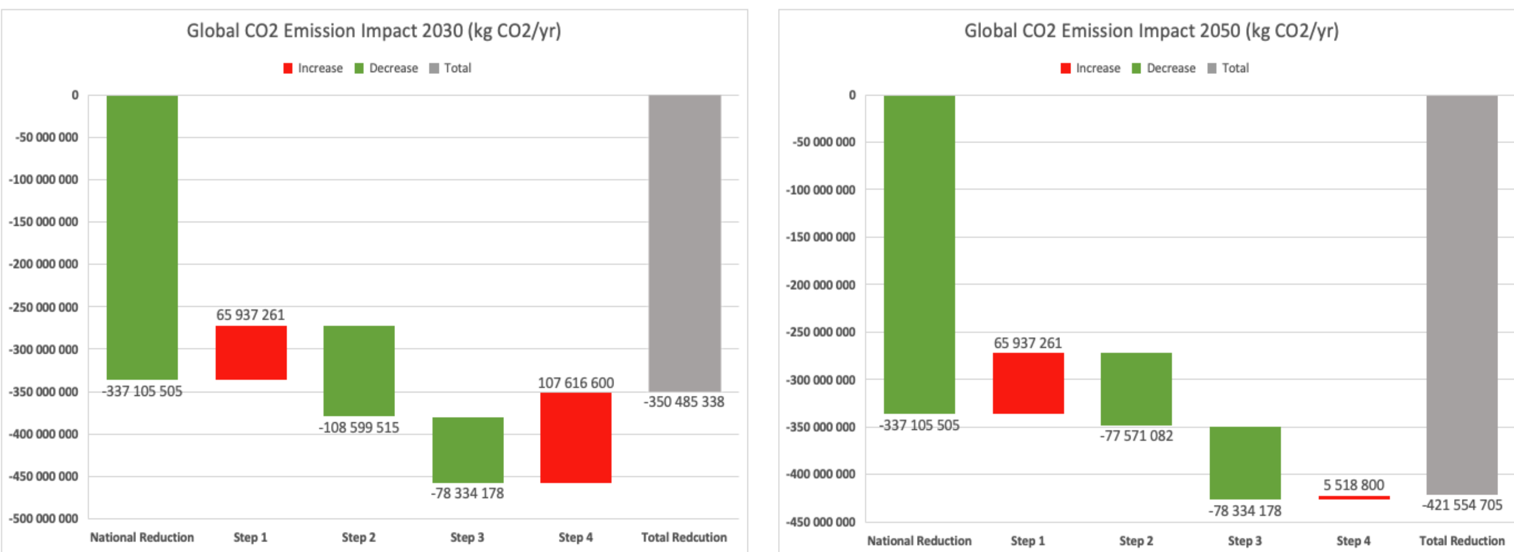


Figure 19: Waterfall Diagram - Net Global CO2 Reduction (Appendix 2.8)

The analysis presents four calculation steps to determine the global CO_2 emissions impacted by the BGE project. Step 1 resulted in an increased CO_2 emission of 65,937 tons per year due to increased gas consumption in Europe. This is because Norwegian gas production will displace other gas production, while 23% will be absorbed through increased demand. Step 2 resulted in a reduction of CO_2 emissions by 108,599 tons per year due to the substitution of coal with gas. The increased supply of gas will reduce coal consumption in LNG-importing countries. Step 3 resulted in a further reduction of CO_2 emissions by 78,834 tons per year due to the displacement effect of Norwegian gas production. This effect is based on the emissions associated with the production, processing, and transport of Norwegian gas, which is subtracted from the avoided emissions from displaced LNG production. Step 4 of the analysis predicts an increase in CO_2 emissions of 107,616 tons by 2030 because of higher power production needed for electrification of offshore facilities. By 2050, it is estimated that the rate of CO_2 emission increase will be reduced by an average of 24%, leading to an expected emission level of 5,518 tons. Calculations on steps (1 to 4) is presented in appendix 2.9-2.12.

The impact of each calculation step on CO_2 emissions reduction from 2030 to 2050 is presented in Figure 20. The figure provides a visual representation of the impact of each step, showing that Step 2 has the most impact on CO_2 emissions reduction, followed by Step 3. Step 1 has the least impact, while Step 4 shows an increase in CO_2.

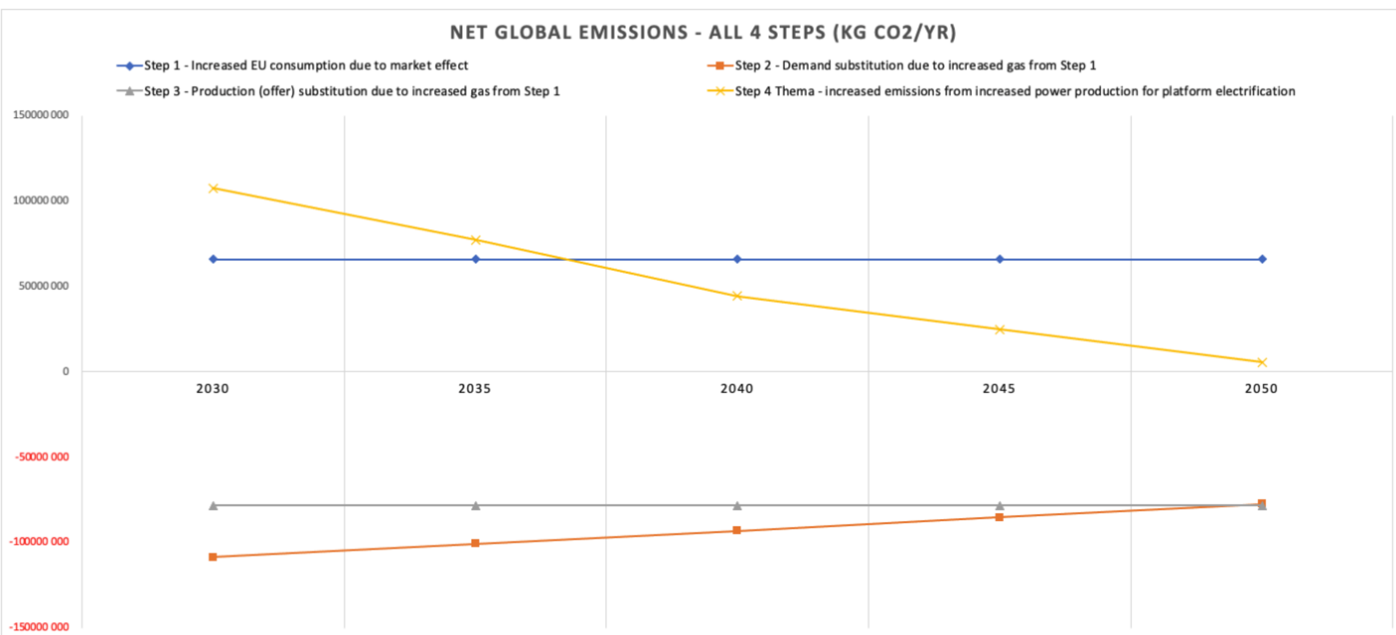


Figure 20: Scatter plot - Step 1-4 Global CO2 Impact Results (Appendix 2.8)

Figure 21 below provides a visual representation of the CO_2 reduction potential of the BGE project, highlighting its positive impact at both national and global levels. The graph shows the annual CO_2 reduction over the project's lifespan, with the blue and green lines representing the national and global levels. It shows that if the BGE project is implemented, it will have a greater impact on reducing global CO_2 emissions compared to reducing emissions at the national level. The results indicate that by 2030, the project will reduce CO_2 emissions by an additional 4% more than the national CO_2 reduction, while it will be 25% in 2050. Over time, the global CO_2 reduction is getting more significant because of the expected reduction in CO_2 emissions linked to new power generation in Step 4.

These findings emphasize the significant contribution of the BGE project in tackling climate change on a global scale. The project's ability to achieve greater CO_2 reductions worldwide indicates its importance in not only addressing national emissions but also making a significant impact towards global CO_2 reduction goals. While the study provides valuable insights into the potential impact of offshore electrification (BGE), the results are based on a specific set of data and assumptions. Changing the input variables for each calculation step would result in different outcomes. Therefore, it is crucial to critically evaluate the data sources and assumptions made in the study to fully understand the impact.

	2030	2035	2040	2045	2050	
National CO2 Reduction	337 105 505	337 105 505	337 105 505	337 105 505	337 105 505	kg CO2/yr
Global CO2 Reduction	350 485 338	373 081 629	398 437 321	409 996 013	421 554 705	kg CO2/yr
Global CO2 Reduction effect vs National	104%	111%	118%	122%	125%	

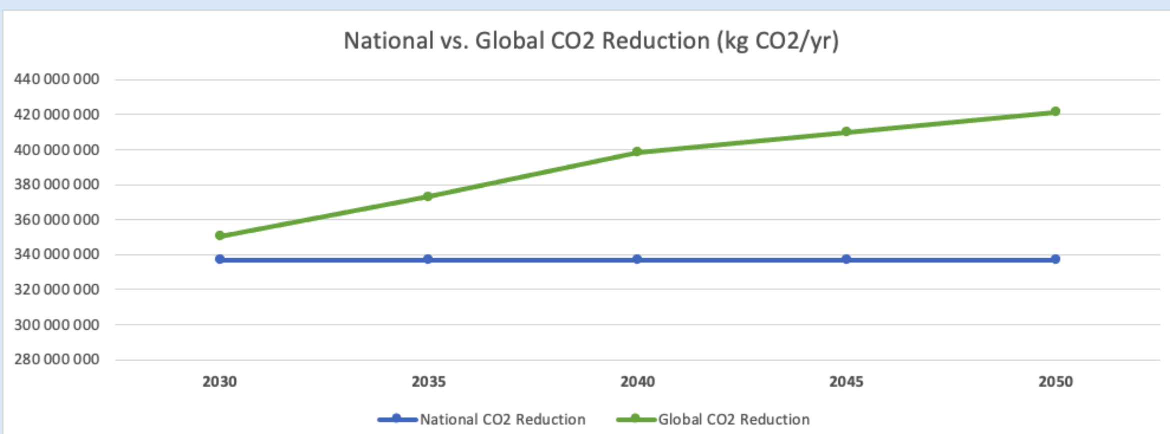


Figure 21: National vs Global CO2 Reduction (Appendix 2.8)

A sensitivity analysis was performed to assess how sensitive the results of the Environmental Impact Analysis are to different variables used in the calculations. Figure 22 shows how a 10% increase and decrease of the presumed most important estimates and assumptions, used in step 1-4, affects the average global CO_2 reduction annually. It is important to acknowledge that certain variables have a greater potential for variability compared to others.

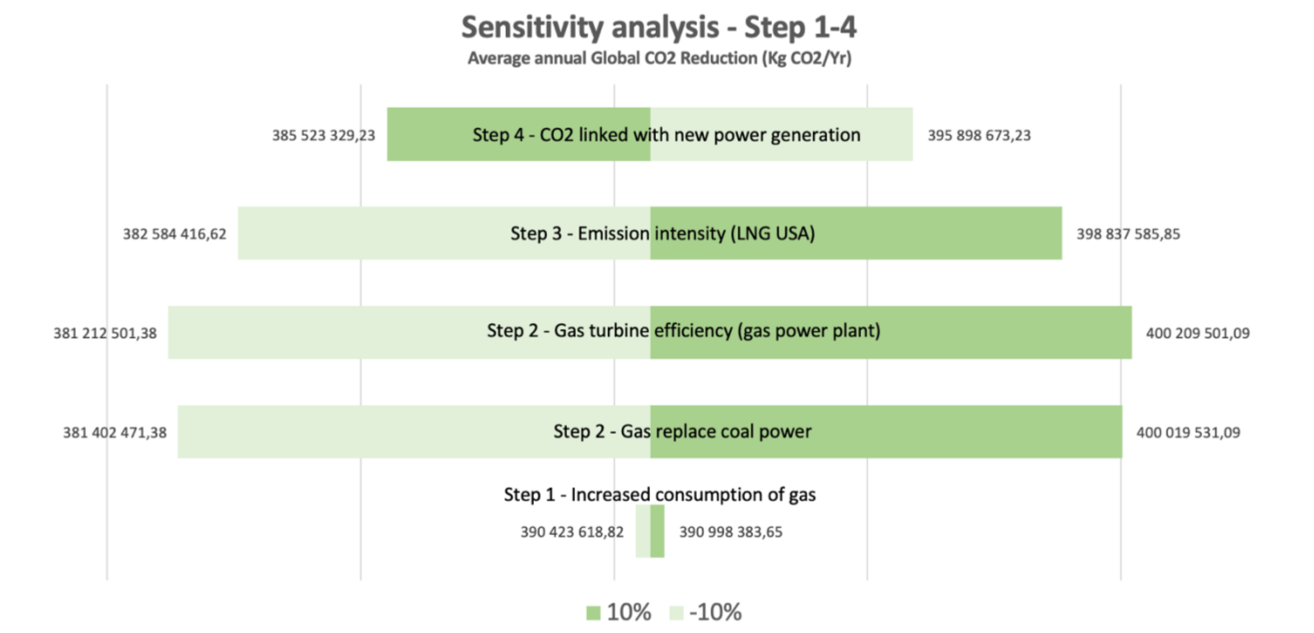


Figure 22: Sensitivity analysis -step 1-4 (appendix 2.8)

The results show that the Environmental Impact analysis was most sensitive to a 10% change in gas turbine efficiency on power plants, from step 2. Emission intensity from LNG production in USA (step 3) and the percentage of gas replacing coal power (step 2) does also have a notable impact. On the other hand, step 1, which examines increased gas consumption, has a relatively minor effect compared to the other steps.

It is important to note that the uncertainties related to emission intensity from LNG production (step 3) and gas turbine efficiency on power plants (step2) are considerably smaller than the uncertainties surrounding the other variables. Therefore, while the sensitivity analysis highlights their influence on the results, the likelihood of significant changes happening is low.

The percentage of gas replacing coal power (step 2) is obtained from Rystad Energy. They estimated that 70% of the increased gas supply to Europe will replace coal power in 2030. This estimate contains large uncertainties as it involves predicting several factors about the future energy market. In the Environmental Impact Analysis for this thesis, it is assumed that the percentage decreases by 1 each year during the BGE project's lifetime. This is also an assumption about the future energy market that could potentially have large deviations from reality. CO2 emissions linked with new power generation (step 4), relies on data provided by Thema Consulting Group. These estimates are a result of several assumptions of how a permanent increased demand in the power market impact emissions in quota-obliged sectors in Europe. It is therefore important to be aware that the data collected from this study also contains considerable uncertainties.

Overall, the sensitivity analysis highlights the varying impacts of different steps in the Environmental Impact Analysis. It is important to consider the degree of uncertainties surrounding the variables when interpreting the analysis. Therefore, the percentage of gas replacing coal power (step 2) and CO2 emissions linked with new power generation (step 4) may be the most important inputs to consider in the Environmental Impact analysis.

6.4. Results – CO_2 Abatement cost

Figure 23 illustrates the results from the abatement cost analysis, whereas a 7% discount rate (DR) give an abatement cost of 2812 NOK/ton CO_2. Since it is common for authorities to use a discount rate of 4 %, the abatement cost would then be reduced to 1870 NOK/ton CO_2 for the Base Case. The societal value of the emissions reduction is considered by using the expected quota price and tax level, which is 2230 NOK in this case. In conclusion, the analysis reveals that the choice of discount rate significantly impacts the economic viability of the BGE project. When using a 4% discount rate, the CO_2 abatement cost is lower than the societal value of 2230 NOK. This indicates that the project is economically profitable for society (cost effective). However, when a higher discount rate of 7% is employed, the estimated CO_2 abatement cost rises to 2812 NOK per ton of CO_2. This exceeds the current CO_2 price, indicating that the project is economically unprofitable for society. It is noteworthy to keep in mind that the results of the Environmental impact analysis presented in Chapter 6.3 indicate that there will be a greater CO_2 reduction globally compared to nationally. This raises the question of whether a high abatement cost can be accepted considering its potential as a significant measure for reducing CO_2 not only at a national level but also globally.

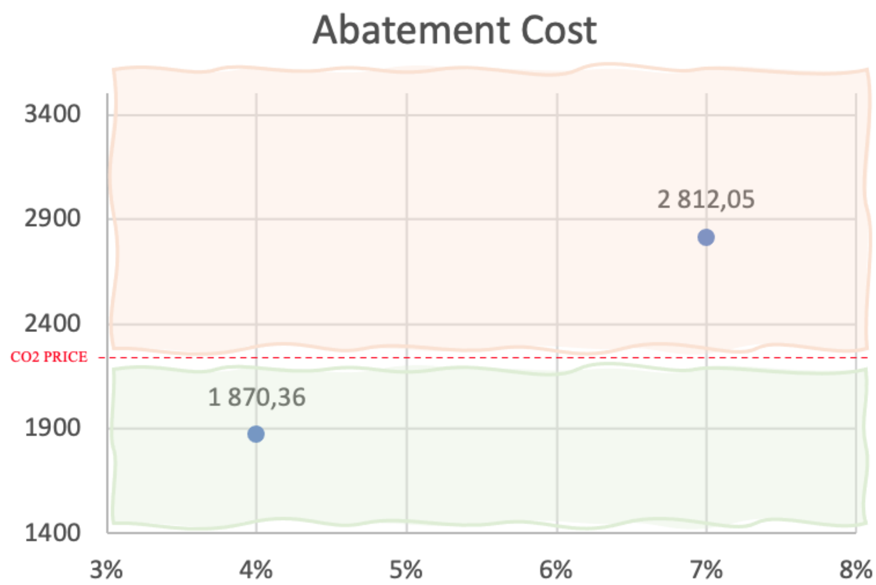


Figure 23: Abatement Cost - 4% & 7% DR

A sensitivity analysis is done on the abatement cost, by using a discount rate of 7% and a sensitivity range of plus/minus 10%. Figure 24 presents the finding of the sensitivity done. To ensure that the most significant input variables are identified, a thorough analysis of the project's financial parameters was undertaken. As a result, the CapEx, gas turbine efficiency, gas price, electricity price, discount rate and CO_2 price were selected as the most critical input variables to be evaluated. The accuracy of the abatement cost result is influenced by assumptions and simplifications made during data gathering, particularly regarding CapEx and gas turbine efficiency. These two input variables have the greatest impact on the calculated abatement cost. To achieve a greater accuracy on the abatement cost it would be necessary to have the exact turbine efficiney and CapEx values from each offshore facility. Therefore, it is important to acknowledge these assumptions and their effects on the result.

The Norwegian Petroleum Directorate (NPD) considers the CO_2 abatement cost when evaluating the feasibility of a power from shore project. If the abatement cost exceeds the current CO_2 price, NPD may not approve the project. When the CO_2 price increases, it becomes more favorable for NPD to justify the project as it becomes more socioeconomically beneficial (NPD, 2020, p.32). The CO_2 price does not have a direct impact on the abatement cost, but there is an indirect impact that should be taken into consideration. The price of CO_2 is a factor that influences energy prices, and in turn, affects the abatement cost indirectly.

Figure 24 note: Light green = 10% increase, Dark green = -10% decrease

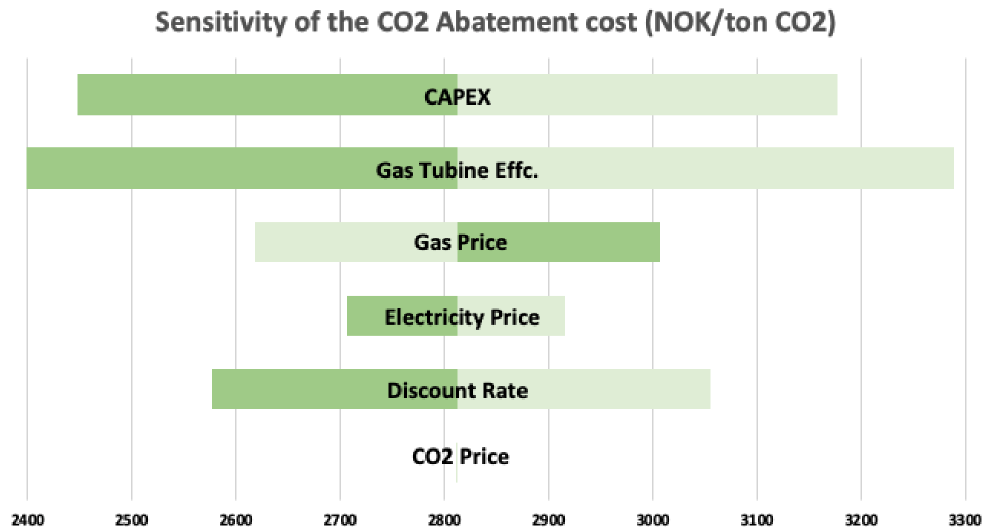


Figure 24: Tornado Diagram - Abatement Cost Sensitivity +-10% (Appendix 2.6)

The abatement cost, which is the cost per unit of emissions reduced, is influenced by several factors, including the level of emissions reduced, investment costs, power prices, and revenues generated from the sales of gas (extra). The greater the emissions reduction and the lower the investment costs, the lower the abatement cost will be. On the other hand, increased electricity prices lead to higher abatement costs, while a decrease in fuel gas consumption due to electrification and an increase in gas prices will lower the abatement cost. Additionally, as mentioned the choice of discount rate also affects the CO2 abatement cost. If the discount rate is raised, such as to 7%, the abatement cost will be higher.

7. Conclusion

This master thesis includes analyses and an evaluation of the BGE project to determine if it provides a financially viable solution for reducing national and global CO_2 emissions. Specifically, this thesis has explored the potential for electrification of three oil and gas facilities on the Norwegian Continental shelf, focusing on the Jotun A, Ringhorne and Grane facilities. In order to analyze the impact of the project, two scenarios have been compared. The first scenario, known as the Zero Alternative, involves powering the facilities with gas turbines, while the second scenario, called the Base Case, involves powering the facilities with electricity from shore.

Based on the economic analysis, the BGE project has been found to have a positive net present value after tax of 279 MNOK when a 4% discount rate is applied. However, when the discount rate is increased to 7%, the NPV becomes -452 MNOK. The project's financial viability depends not only on the choice of discount rate but also on the accuracy of other estimates and assumptions. At a national level, the BGE project is anticipated to annually reduce CO_2 emissions by 337,106 tons through the replacement of gas turbines with power sourced from the shore. Furthermore, when considering global CO_2 reduction, it was estimated that the project would contribute to even greater emissions reductions compared to the national. By 2030, the annual global CO_2 reduction is projected to reach 352 million tons, and by 2050, it is expected to reach 420 million tons. This indicates that the BGE project, along with other electrification projects on the NCS may have a higher potential for reducing CO_2 emissions than previously anticipated.

In order for the project to be considered a cost-effective measure for reducing national CO_2 emissions, it is desired that the abatement cost of the project remains below the CO_2 price, which is 2230 NOK over the project's lifetime. This signifies that the project is economically profitable for society. At a discount rate of 4%, the estimated CO_2 abatement cost is 1870 NOK/ton, falling comfortably below the CO_2 price. However, at a discount rate of 7%, the abatement cost rises to 2812 NOK/ton, exceeding the CO_2 price. The results of both the NPV and abatement cost are highly influenced by factors such as investment costs, gas turbine efficiency, discount rate and the CO_2 price, as revealed in the sensitivity analysis.

In conclusion, the Balder/Grane electrification project could be a promising solution for effectively reducing both national and global CO_2 emissions in alignment with the goals outlined in the Paris Agreement. Additionally, it contributes significantly to Norway's commitment to attaining carbon neutrality by 2050. The viability of the project, as indicated by the net present value (NPV) and CO_2 abatement cost, depends on the chosen discount rate. However, the project holds potential as a financially feasible investment, particularly if efforts are made to reduce the associated investment costs. If successfully executed, the project can serve as a positive example for the oil and gas industry, showcasing how a transition to cleaner energy sources can be achieved. By taking such action, the project plays a vital role in global efforts to combat climate change.

Although this is the conclusion for this master thesis, a careful evaluation of the key input variables and further analysis is necessary to ensure the project's economic viability and reduce uncertainties related to the case study. All in all, the BGE project could be a promising and financially viable solution that holds great potential to reduce CO_2 emissions.

Future Research

Based on the analyses and evaluation of the Balder/Grane electrification project, there are several areas of future work that could be undertaken to improve the accuracy and reliability of the results. Firstly, it is important to gather more accurate data around the gas turbines, that would have been used in the zero alternative, to reduce uncertainties around the CO_2 emission, fuel gas consumption and power generation from the two scenarios. The second area involves gathering more data and information to improve estimates such as future gas prices, power prices, CapEx, OpEx and ABEX. The third area requires considering the yearly production (oil and gas) variations, which would impact the results.

To complete this master thesis within the given timeframe, various assumptions had to be made and simplifications applied to enable the necessary calculations and analyses. Ideally, to improve prediction accuracy, it is helpful to gather estimates from different sources and organize them systematically. By utilizing Monte Carlo simulations, a better assessment can be made regarding the likelihood of various outcomes.

Lastly, possibilities for future work could be to compare the PFS with offshore wind electrification and gas power plant with carbon capture. This could help to determine the viability of offshore electrification with the use of different power sources. By addressing these areas of future work, the analysis and evaluation of the Balder/Grane electrification project can be improved, making it a more valuable contribution to the energy and climate policy debates.

Bibliography

Andreev, L. & Skulstad, A. (2020). *Ringvirkninger av å elektrifisere sokkelen og fergedriften.* (VA-rapport 2020/25). Retrieved from https://vista-analyse.no/site/assets/files/6897/va-rapport_2020-25_ringvirkninger_av_a_elektrifisere_sokkelen_og_fergedriften.pdf

Cuviella-Suarez, C., Colmenar-Santos, A., Borge-Diez, D., Rosales-Asensio, E. (2019). Sanitary-ware factories: heat recovery strategies to optimize energy and water consumption. *Energy Procedia. 157*, 719-736. https://doi.org/10.1016/j.egypro.2018.11.238

DNV GL. (2015). *Teknologiutvikling og klimagassutslipp fra petroleumsvirksomheten fram mot 2030 og et lavutslippssam funn i 2050* (Sluttrapport 1, Rev. 4). Retrieved from https://www.miljodirektoratet.no/globalassets/publikasjoner/m393/m393.pdf

El-Montasser, G., Ben-Salha, O. (2019). A new methodology for assessing the energy use-environmental degradation nexus. *Environ Monit Assess 191(9).* https://doi.org/10.1007/s10661-019-7761-0

Equinor. (2022). *Third quarter 2022 review.* Retrieved from https://cdn.equinor.com/files/h61q9gi9/global/47fc2210056cff86ad250974c1d874389dd414ab.pdf?q3-2022-financial-statements-and-review.pdf

Equinor. *Electrification of platforms.* Retrieved from 2023a, April 10 https://www.equinor.com/energy/electrification-of-platforms

Equinor. *Natural Gas Converter*. Retrieved from 2023b, March 30 https://ngc.equinor.com/

European Commission. *EU Emissions Trading System (EU ETS).* Retrieved from 2023a, May 11 https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en

European Commission. *Market Stability Reserve.* Retrieved from 2023b, May 11 https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/market-stability-reserve_en

Fernando, J. (2023a, March 30). *Internal Rate of Return (IRR) Rule: Definition and Example*. Investopedia. https://www.investopedia.com/terms/i/irr.asp

Fernando, J. (2023b, May 4). *Capital Expenditure (CapEx).* Investopedia. https://www.investopedia.com/terms/c/capitalexpenditure.asp

FN-Sambandet (2023, March 21): KlimaEndringer. https://www.fn.no/tema/klima-og-miljoe/klimaendringer

Gallant, C. (2022, May 23). *Net Present Value vs. Internal Rate of Return*. Investopedia. https://www.investopedia.com/ask/answers/05/npv-irr.asp

Gassco. *The integrated gas transport system.* Retrieved from 2023, May 3 https://www.gassco.no/static/transport-2.0/

Gravdal, M. (2022). *Offshore Electrification – An overview of technologies, risks and costs associated to the Norwegian Continental Shelf.* [Master's thesis]. University of Stavanger. *https://uis.brage.unit.no/uis-xmlui/handle/11250/3022371*

IEA. (2021, May 17). *Net Zero by 2050 Data Explorer*. https://www.iea.org/data-and-statistics/data-tools/net-zero-by-2050-data-explorer

Kagan, J. (2023, February 26). *Payback Period Explained, With the Formula and How to Calculate it.* Investopedia. https://www.investopedia.com/terms/p/paybackperiod.asp

Kawasaki Kisen Kaisha LTD. *What is an FPSO*. Retrieved from 2023, May 15 https://www.kline.co.jp/en/service/energy/about/fpso.html#:~:text=What%20is%20an%20FPSO%3F,or%20transferred%20onshore%20through%20pipeline

Konkraft. (2021). *Framtidens Energinæring På Norsk Sokkel - Statusrapport 2021* (Konkraftrapport 2021-2). Retrieved from *https://offshorenorge.no/contentassets/f1b1a7da6aaa4a9aa95b7e3b96630283/statusrapport-2021---framtidens-energinaring-pa-norsk-sokkel---klimastrategi-mot-2030-og-2050.pdf*

Law Insider. *Abandonment Costs definition.* Retrieved from 2023, May 10 https://www.lawinsider.com/dictionary/abandonment-costs

Megavind. (2015). *Megavind LCOE Model Guidelines and documentation.* Retrieved from *https://megavind.greenpowerdenmark.dk/files/media/document/1500318%20Documentation%20and%20guidelines.pdf*

Meld.St.36. (2020-2021). *Energi til arbeid – langsiktig verdiskaping fra norske energiressurser*. Ministry of Petroleum and Energy. https://www.regjeringen.no/contentassets/3d9930739f9b42f2a3e65adadb53c1f4/no/pdfs/stm202020210036000dddpdfs.pdf?fbclid=IwAR2i1trad7ezHt_xs7JGtT08HqARFAF4V4q8mImKw1EbOvyq_EMmpEFoCF0

Metro Services. (2020, May 15). *Waste Heat Recovery Systems.* https://metroservicesinc.com/combustion-engineering-maintenance-chattanooga/waste-heat-recovery-systems#:~:text=Methods%20for%20waste%20heat%20recovery,create%20electrical%20or%20mechanical%20power

Miljøstatus. (2022, November 3). *Norske utslipp og opptak av klimagasser.* Miljødirektoratet. https://miljostatus.miljodirektoratet.no/tema/klima/norske-utslipp-av-klimagasser/

NASA. (2023, April 20). *The causes of climate change*. https://climate.nasa.gov/causes/

Nilsen, J. (2022, June 20). *Kan frigjøre 11 TWh ved å elektrifisere sokkelen med flytende havvind.* Europower. https://www.europower.no/havvind/-kan-frigjore-11-twh-ved-a-elektrifisere-sokkelen-med-flytende-havvind/2-1-1226491

Norges Bank. (2020, April 2). *Inflasjon. https://www.norges-bank.no/tema/pengepolitikk/Inflasjon/*

Norsk Petroleum. (2022, June 6). *Utslipp til luft*. ttps://www.norskpetroleum.no/miljo-og-teknologi/utslipp-til-luft/#:~:text=Olje-%20og%20energidepartementet-,Utslipp%20av%20klimagasser,av%20de%20samlede%20norske%20klimagassutslippene

Norsk Petroleum. (2023a, Januar 24). *Rørtransportsystemet,* https://www.norskpetroleum.no/en/production-and-exports/the-oil-and-gas-pipeline-system/

Norsk Petroleum. (2023b, March 29). *Eksport av olje og gass.* https://www.norskpetroleum.no/produksjon-og-eksport/eksport-av-olje-og-gass/

Norsk Petroleum. *Grane*. Retrieved from 2023a, May 15 https://www.norskpetroleum.no/fakta/felt/grane/

Norsk Petroleum. *Omregning.* Retrieved from 2023b, April 10 https://www.norskpetroleum.no/kalkulator/om-kalkulatoren/

NPD. (2020). *Kraft Fra Land til norsk sokkel.* (Rapport 2020). Retrieved from https://www.npd.no/globalassets/1-npd/publikasjoner/rapporter/2020/kraft-fra-land-til-norsk-sokkel/kraft-fra-land-til-norsk-sokkel-rapport-2020.pdf

NVE. (2021). *LANGSIKTIG KRAFTMARKEDSANALYSE 2021 – 2040* (NVE Rapport nr. 29/2021). Retrieved from:https://publikasjoner.nve.no/rapport/2021/rapport2021_29.pdf?fbclid=IwAR3F7o_oVtogzR1ROROgREh2GKyYgyKaWqdypoBWP7rOctQYyZUE4rmSqrE

NVE. (2022, December 16). *Samfunnsøkonomiske vurderinger*. https://www.nve.no/energi/energisystem/nett/kraftsystemutredninger/veiledningsmateriale/samfunnsoekonomiske-vurderinger/

Offshore Technology. (2020. April 16). *Ringhorne Field, North Sea.* https://www.offshore-technology.com/projects/ringhorne-field-north-sea/

Pwc. (2023a, February 9). *Corporate – Deductions.* https://taxsummaries.pwc.com/norway/corporate/deductions

Pwc. (2023b, February 9). *Corporate – Taxes on corporate income.* *https://taxsummaries.pwc.com/norway/corporate/taxes-on-corporate-income*

Regjeringen. (2020, August 12). *Dette er klimakvoter*.https://www.regjeringen.no/no/tema/klima-og-miljo/klima/innsiktsartikler-klima/klimakvoter/id2076655/

Regjeringen. (2022a, December 22). *Karbonprisbaner for bruk i samfunnsøkonomiske analyser.* https://www.regjeringen.no/no/tema/okonomi-og-budsjett/statlig-okonomistyring/karbonprisbaner-for-bruk-i-samfunnsokonomiske-analyser/id2878113/

Regjeringen. (2022b, November 3). *Nytt norsk klimamål på minst 55 prosent.* https://www.regjeringen.no/no/aktuelt/nytt-norsk-klimamal-pa-minst-55-prosent/id2944876/

Riboldi, L. & Nord, L.O. (2017). Concepts for lifetime efficient supply of power and heat to offshore installations in the North Sea. *Energy Conversion and Management*, *148*, 860-875. https://doi.org/10.1016/j.enconman.2017.06.048

Riboldi, L., Völler, S., Korpås, M., & Nord, L. O. (2019). An Integrated Assessment of the Environmental and Economic Impact of Offshore Oil Platform Electrification. *Energies*, *12*(11), 2114. http://dx.doi.org/10.3390/en12112114

Ross, S. (2023, April 27). *CapEx vs. OpEx: What's the Difference?,* Investopedia. https://www.investopedia.com/ask/answers/112814/whats-difference-between-capital-expenditures-capex-and-operational-expenditures-opex.asp

Ross, S.A., Westerfield, R.W., Jaffe, J.F. & Jordan, B.D. (2018). *Corporate Finance: Core principles & Applications* (5th ed.). McGraw-Hill Education.

Rystad Energy. (2023). *Netto klimagassutslipp fra økt olje- og gassproduksjon på norsk sokkel.* Retrieved from https://www.regjeringen.no/contentassets/f5fc522f50674c1f9e0b5db47c264dbe/netto-klimagassutslipp-fra-okt-olje-og-gassproduksjon-pa-norsk-sokkel_hovedrapport.pdf

Rød, T. (2023, Februar 16). *Capital Markets update*. Vår Energi. https://cmu.plaii.no/main.php

SSB. (2022a, November 3). *Utslipp til luft.* https://www.ssb.no/natur-og-miljo/forurensning-og-klima/statistikk/utslipp-til-luft

SSB. (2022b). *Emission factors used in the estimation of emissions from combustion.* Retrieved from *https://www.ssb.no/_attachment/404602/*

SSB. (2023, Januar 18). *Skyshøye gasspriser ga historisk høy eksport I 2022.* https://www.ssb.no/utenriksokonomi/utenrikshandel/statistikk/utenrikshandel-med-varer/artikler/skyhoye-gasspriser-ga-historisk-hoy-eksport-i-2022

SSB. *12824: Electricity balance (MWh) 2010M01 – 2023M03*. Retrieved from 2023, March 23 https://www.ssb.no/en/statbank/table/12824/

Statnett. (2022). *Kortsiktig Markedsanalyse 2022-27*. Retrieved from https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/kma2022-2027.pdf

Statnett. *Data from the power system*. Retrieved from 2023, March 21 https://www.statnett.no/en/for-stakeholders-in-the-power-industry/data-from-the-power-system/

The Investopedia Team. (2023, March 17). *Feasibility Study*. Investopedia. https://www.investopedia.com/terms/f/feasibility-study.asp

Thema Consulting Group. (2023). *Elektrifisering av olje- og gassektoren – har det global klimaeffekt?* (2022-23). Retrieved from https://offshorenorge.no/contentassets/97cb69dec47d4ecbaff23c16af5ce50c/thema-rapport-2022-23_elektrifisering-av-olje--og-gassektoren-_har-det-global-klimaeffekt---endelig.pdf

University of the Witwatersrand. (2023, April 6). *Research Support: Research Methodology.* https://libguides.wits.ac.za/c.php?g=693518&p=4914913

Vår Energi. (2020, June 15). *Prosjektstart for storsatsing i Nordsjøen.* https://varenergi.no/nyheter/prosjektstart-for-storsatsing-i-nordsjoen/

Vår Energi. (2021). *Sustainability report 2021*. Retrieved from *https://varenergi.no/wp-content/uploads/2022/04/Va%CC%8Ar-Energi-Sustainability-report-2021-web.pdf*

Appendix

Appendix 1 Case study - Description & Data

Appendix 1.1a: *Input data – CO2 & Fuel gas calculation: Further used in Environmental Impact Analysis*

JOTUN A - NO ELECTRIFICATION/ELECTRIFICATION

Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh

Jotun A - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification

Power generation		28,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		245 280	MWh/yr
Turbine efficiency		30,00%	
Fuel gas consumption (turbin)		817 600	MWh/yr
Fuel gas consumption (turbin)		499 145	boe/yr
Emission from turbines		172 186 560,00	kg CO2/yr
Emission from turbines		172 186,56	**ton CO2/yr**
Reduced emissions due to electrification			
100% eletrification	-	172 186,56	ton CO2/yr
Extra gas - export (fuel gas)		73 584 000,00	**Sm3**

RINGHORNE - NO ELECTRIFICATION/ELECTRIFICATION

Fuel	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh

Ringhorne - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification

Power generation		5,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		43 800	MWh/yr
Turbine efficiency		30%	
Fuel gas consumption (turbin)		146 000	MWh/yr
Fuel gas consumption (turbin)		89 133	boe/yr
Emission from turbines		30 747 600,00	kg CO2/yr
Emission from turbines		30 747,60	ton CO2/yr
Reduced emissions due to electrification			
100% eletrification	-	30 747,60	**ton CO2/yr**
Extra gas - export (fuel gas)		13 140 000,00	**Sm3**

GRANE - NO ELECTRIFICATION/ELECTRIFICATION

Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh

Grane - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification

Power generation		30,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		262 800	MWh/yr
Turbine efficiency		30%	
Fuel gas consumption (turbin)		876 000	MWh/yr
Fuel gas consumption (turbin)		534 799	boe/yr
Emission from turbines		184 485 600,00	kg CO2/yr
Emission from turbines		184 485,60	ton CO2/yr
Reduced emissions due to electrification			
100% eletrification	-	184 485,60	**ton CO2/yr**
Extra gas - export (fuel gas)		78 840 000,00	**Sm3**

JOTUN A - BASE CASE (ELECTRIFICATION), 1X30% FOR HEATING GENERATION

Fuel gas	Source: SSB	2,34	**ton CO2/1000 Sm3**
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	**kg CO2/boe**
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh

Jotun A - Calculation assumptions, Gas use, CO2 Emission & Electrification

Power generation		6,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		52 560	MWh/yr
Turbine efficiency		22%	
Fuel gas consumption (turbin)		238 909	MWh/yr
Fuel gas consumption (turbin)		145 854	boe/yr
Emission from turbines		50 314 254,55	kg CO2/yr
Emission from turbines		50 314,25	ton CO2/yr
CO2 emission - heating generation due to electrification			
Increased CO2 due to eletrification		50 314,25	**ton CO2/yr**
Fuel gas		21 501 818,18	**Sm3**

DATA FROM RYSTAD ENERGY REPORT - USED IN STEP 1-4 CALCUALTIONS

Rystad energy & Thema Consulting groupe studies

Data

Fuel gas	1,99	**ton CO2/1000 SM3**
Fuel gas	1,99	kg CO2/Sm3
Fuel gas	179,1	g CO2/kWh
Fuel gas	293,37	**kg CO2/boe**
1 boe (NCV)	1 638,00	kWh
1 kWh	3,60	MJ
1 SM3 (GCV)	40,00	MJ
1 SM3 (GCV)	11,11	kWh

Appendix 1.1b: *Input data – CO2 & Fuel gas calculation: Further used in Economic Analysis*

JOTUN A - NO ELECTRIFICATION/ELECTRIFICATION			
Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh
Jotun A - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification			
Power generation		28,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		245 280	MWh/yr
Turbine efficiency		30,00%	
Fuel gas consumption (turbin)		817 600	MWh/yr
Fuel gas consumption (turbin)		499 145	boe/yr
Emission from turbines		172 186 560,00	kg CO2/yr
Emission from turbines		172 186,56	ton CO2/yr
Reduced emissions due to electrification			
100% eletrification		172 186,56	**ton CO2/yr**
Extra gas - export (fuel gas)		73 584 000,00	**Sm3**

RINGHORNE - NO ELECTRIFICATION/ELECTRIFICATION			
Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh
Ringhorne - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification			
Power generation		5,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		43 800	MWh/yr
Turbine efficiency		30%	
Fuel gas consumption (turbin)		146 000	MWh/yr
Fuel gas consumption (turbin)		89 133	boe/yr
Emission from turbines		30 747 600,00	kg CO2/yr
Emission from turbines		30 747,60	ton CO2/yr
Reduced emissions due to electrification			
100% eletrification		30 747,60	**ton CO2/yr**
Extra gas - export (fuel gas)		13 140 000,00	**Sm3**

GRANE - NO ELECTRIFICATION/ELECTRIFICATION			
Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh
Grane - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification			
Power generation		30,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		262 800	MWh/yr
Turbine efficiency		30%	
Fuel gas consumption (turbin)		876 000	MWh/yr
Fuel gas consumption (turbin)		534 799	boe/yr
Emission from turbines		184 485 600,00	kg CO2/yr
Emission from turbines		184 485,60	ton CO2/yr
Reduced emissions due to electrification			
100% eletrification		184 485,60	**ton CO2/yr**
Extra gas - export (fuel gas)		78 840 000,00	**Sm3**

JOTUN A - BASE CASE (ELECTRIFICATION), 1X30% FOR HEATING GENERATION			
Fuel gas	Source: SSB	2,34	ton CO2/1000 Sm3
Fuel gas		2,34	kg CO2/Sm3
Fuel gas		210,6	g CO2/kWh
Fuel gas		344,96	kg CO2/boe
1 boe		1 638,00	kWh
1 kWh		3,60	MJ
1 SM3		40,00	MJ
1 SM3		11,11	kWh
Jotun A - Calculation assumptions, Gas use, CO2 Emission & Electrification			
Power generation		6,00	MW
Hours/yr		8 760,00	
Availability of power turbines		100%	
Power production per year		52 560	MWh/yr
Turbine efficiency		22%	
Fuel gas consumption (turbin)		238 909	MWh/yr
Fuel gas consumption (turbin)		145 854	boe/yr
Emission from turbines		50 314 254,55	kg CO2/yr
Emission from turbines	-	50 314,25	ton CO2/yr
CO2 emission - heating generation due to electrification			
Increased CO2 due to eletrification	-	50 314,25	**ton CO2/yr**
Fuel gas	-	21 501 818,18	**Sm3**

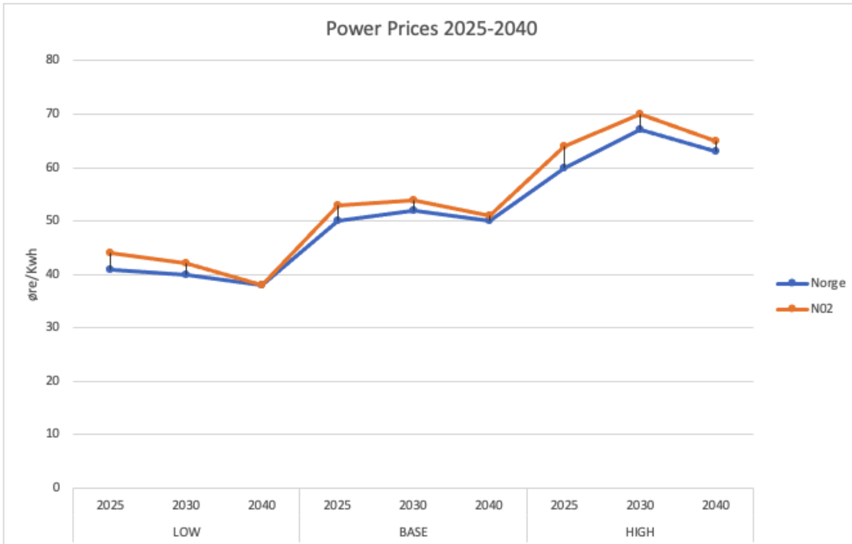
SUMMARY - THE ZERO ALTERNATIVE & ELETRIFICATION CASE (BASE CASE)

USED IN NPV CALCULATIONS

The zero alternative (No electrification, CO2 Emission)			
CO2 Emissions from Turbines			
Jotun A	ton CO2/yr		172 186,56
Ringhorne	ton CO2/yr		30 747,60
Grane	ton CO2/yr		184 485,60
Sum CO2 Emission	**ton CO2/yr**		**387 419,76**
Fuel gas used offshore - turbines			
Jotun A	Sm3/yr		73 584 000,00
Ringhorne	Sm3/yr		13 140 000,00
Grane	Sm3/yr		78 840 000,00
Sum fuel gas used offshore - turbines	**Sm3/yr**		**165 564 000,00**
Power production from turbines			
Jotun A	MWh/yr		245 280
Ringhorne	MWh/yr		43 800
Grane	MWh/yr		262 800
Summary			
Sum CO2 Emission	**ton CO2/yr**		**387 419,76**
Sum fuel gas used offshore - turbines	**Sm3/yr**		**165 564 000,00**
Sum power production from turbines	**MWh/yr**		**551 880**

Base case - Electrification study (Reduced CO2)			
CO2 reduction from turbines due to electrification			
Jotun A	ton CO2/yr		172 186,56
Jotun A 1x30%	ton CO2/yr	-	50 314,25
Ringhorne	ton CO2/yr		30 747,60
Grane	ton CO2/yr		184 485,60
Sum CO2 reduction	**ton CO2/yr**		**337 105,51**
Saved fuel gas offshore (extra supply)			
Jotun A	Sm3/yr		73 584 000,00
Jotun A 1x30%	Sm3/yr	-	21 501 818,18
Ringhorne	Sm3/yr		13 140 000,00
Grane	Sm3/yr		78 840 000,00
Saved fuel gas offshore (extra supply)	**Sm3/yr**		**144 062 181,82**
Power purchase from shore			
Jotun A	MWh/yr		245 280
Jotun A	MWh/yr	-	52 560
Ringhorne	MWh/yr		43 800
Grane	MWh/yr		262 800
Summary			
Sum CO2 reduction	**ton CO2/yr**		**337 105,51**
Saved fuel gas offshore (extra supply)	**Sm3/yr**		**144 062 181,82**
Sum power purchase from shore	**MWh/yr**		**499 320**

Appendix 1.2 *Power prices – NO2 vs. Norway*



Appendix 1.3*: Table of data used to calculate co2 prices [source]*

	1. Kvotepliktig utslipp (unntatt luftfart og petroleum)	2. Ikke-kvotepliktig utslipp	3. Petroleum	4. Luftfart	5. Opptak og utslipp i skog- og arealbruk
2023	798	952	1559	1447	798
2024	836	1135	1724	1611	836
2025	872	1317	1907	1796	872
2026	915	1500	2121	2016	915
2027	937	1682	2230	2230	937
2028	961	1865	2230	2230	961
2029	985	2047	2230	2230	985
2030	1010	2230	2230	2230	1010
2031	1065	2230	2230	2230	1065
2032	1123	2230	2230	2230	1123
2033	1185	2230	2230	2230	1185
2034	1249	2230	2230	2230	1249
2035	1318	2230	2230	2230	1318
2036	1390	2230	2230	2230	1390
2037	1466	2230	2230	2230	1466
2038	1546	2230	2230	2230	1546
2039	1631	2230	2230	2230	1631
2040	1720	2230	2230	2230	1720
2041	1743	2230	2230	2230	1743
2042	1766	2230	2230	2230	1766
2043	1789	2230	2230	2230	1789
2044	1812	2230	2230	2230	1812
2045	1836	2230	2230	2230	1836
2046	1860	2230	2230	2230	1860
2047	1885	2230	2230	2230	1885
2048	1909	2230	2230	2230	1909
2049	1935	2230	2230	2230	1935
2050	1960	2230	2230	2230	1960
2051	2038	2230	2230	2230	2038
2052	2120	2230	2230	2230	2120
2053	2205	2230	2230	2230	2205
2054	2293	2293	2293	2293	2293
2055	2385	2385	2385	2385	2385
2056	2480	2480	2480	2480	2480
2057	2579	2579	2579	2579	2579
2058	2682	2682	2682	2682	2682
2059	2790	2790	2790	2790	2790
2060	2901	2901	2901	2901	2901

Economic analyses

Appendix 2.1: *Draft of Excel Sheet Calculations – Operational, Cost and Market Assumptions*

Oper. Year (0=no;1=yes)	20	-	-	-	-	-	-	-	1	1	1	1	1	1	1	
Years in operation		-	-	-	-	-	-	-	1	2	3	4	5	6	7	
Years in operation		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037

OPERATINOAL ASSUMPTIONS

Start			2030													
Years	yrs	*	20													
The zero alternative data (no electrification)		SUM	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power genearation offshore (turbines)																
Balder facilities (RH & Jotun A)	MWh/yr		-	-	-	-	-	-	-	289 080	289 080	289 080	289 080	289 080	289 080	289 080	289
Grane facilities	MWh/yr		-	-	-	-	-	-	-	262 800	262 800	262 800	262 800	262 800	262 800	262 800	262
Sum power generation (turbines)	MWh/yr	11 037 600	-	-	-	-	-	-	-	551 880	551 880	551 880	551 880	551 880	551 880	551 880	551
CO2 emission (turbines)																
Balder facilities	ton CO2/yr		-	-	-	-	-	-	-	202 934	202 934	202 934	202 934	202 934	202 934	202 934	202
Grane facilities	ton CO2/yr		-	-	-	-	-	-	-	184 486	184 486	184 486	184 486	184 486	184 486	184 486	184
Sum CO2 emission (turbines)	Kg CO2/yr	7 748 395	-	-	-	-	-	-	-	387 420	387 420	387 420	387 420	387 420	387 420	387 420	387
Sum fuel gas consumption - turbine	MSm3	3 311	-	-	-	-	-	-	-	166	166	166	166	166	166	166	
Electrification data		SUM														
Heating generation offshore -Jotun A	MWh/yr	1 051 200	-	-	-	-	-	-	-	52 560	52 560	52 560	52 560	52 560	52 560	52 560	52
Sum power purchase from shore	MWh/yr	9 986 400	-	-	-	-	-	-	-	499 320	499 320	499 320	499 320	499 320	499 320	499 320	499
Total CO2 reduction	ton CO2/yr	6 742 110	-	-	-	-	-	-	-	337 106	337 106	337 106	337 106	337 106	337 106	337 106	337
Sum saved fuel gas (extra supply to EU)	MSm3	2 881	-	-	-	-	-	-	-	144	144	144	144	144	144	144	

COST & MARKET ASSUMPTIONS

Topside/jacket - details in "input -CAPEX, OPEX & ABEX" sheet

CAPEX			SUM	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	
• Share %/yr			100%	0%	0%	0%	25%	25%	25%	25%	0%	0%	0%	0%	0%	0%	0%	
Onshore development cost	MNOK (real)	-	1 000	-	-	- -	250 -	250 -	250 -	250	-	-	-	-	-	-	-	
Total offshore facilities cost	MNOK (real)	-	9 352	-	-	- -	2 338 -	2 338 -	2 338 -	2 338	-	-	-	-	-	-	-	
Marine installations	MNOK (real)	-	400	-	-	- -	100 -	100 -	100 -	100	-	-	-	-	-	-	-	
Sum Capex	MNOK (real)	-	10 752	-	-	- -	2 688 -	2 688 -	2 688 -	2 688	-	-	-	-	-	-	-	
OPEX																		
Operation and maintanance cost																		
Sum manning increased cost	MNOK (real)	-	480	-	-	-	-	-	-	- -	24 -	24 -	24 -	24 -	24 -	24 -	24 -	
Sum Service/Maintenance increased cost	MNOK (real)	-	680	-	-	-	-	-	-	- -	34 -	34 -	34 -	34 -	34 -	34 -	34 -	
Sum logistics increased cost	MNOK (real)	-	440	-	-	-	-	-	-	- -	22 -	22 -	22 -	22 -	22 -	22 -	22 -	
Sum Opex cost	MNOK (real)	-	1 600	-	-	-	-	-	-	- -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	
Operation and maintanance cost reduction																		
Sum reduced manning offshore cost	MNOK (real)		220	-	-	-	-	-	-	-	11	11	11	11	11	11	11	
Sum reduced Logistics cost	MNOK (real)		100	-	-	-	-	-	-	-	5	5	5	5	5	5	5	
Sum reduced Turbine maintenance cost	MNOK (real)		525								35	5	35	30	35	5	35	
External fibre contract	MNOK (real)		320	-	-	-	-	-	-	-	16	16	16	16	16	16	16	
Sum Reduced Opex	MNOK (real)		1 165	-	-	-	-	-	-	-	67	37	67	62	67	37	67	
Power Purchase	MNOK (real)	-	5 260	-	-	-	-	-	-	- -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	
ABEX																		
Owner's cost	MNOK (real)		-80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Contractor Management & Engineering	MNOK (real)		-82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Sum Topsides / Jacket removal	MNOK (real)		-526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Sum subsea removal	MNOK (real)		-62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Contingency	MNOK (real)		-225	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Sum ABEX	MNOK (real)		-975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Price assumptions																		
• Power price	NOK/MWh		526,67	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527
• Gas price	NOK/Sm3 (real)		3,44	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4
CO2 price	NOK/ton CO2		2230,00	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230

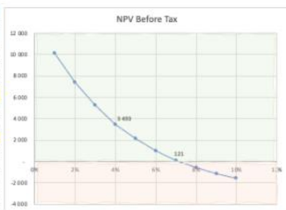
Appendix 2.2: *Draft of Excel Sheet Calculations - Results, Tax, Depreciation (Real and Nominal)*

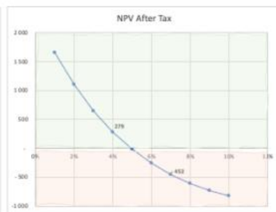
RESULTS, TAX & DEPRECIATION (REAL & NOMINAL) -Electrification

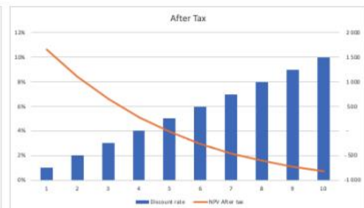
			SUM	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Investments		-	10 752	-	-	- -	2 688 -	2 688 -	2 688 -	2 688	-	-	-	-	-	-	-	-	-	-	-	-
Revenue																						
Saved fuel gas (revenue)	MNOK/yr		9 916	-	-	-	-	-	-	-	496	496	496	496	496	496	496	496	496	496	496	496
Saved CO2 costs (revenue)	MNOK/yr		15 035	-	-	-	-	-	-	-	752	752	752	752	752	752	752	752	752	752	752	752
Sum revenue	MNOK/yr		24 950	-	-	-	-	-	-	-	1 248	1 248	1 248	1 248	1 248	1 248	1 248	1 248	1 248	1 248	1 248	1 248
Costs																						
O&M cost	MNOK/yr	-	1 600	-	-	-	-	-	-	- -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	80 -	80 -
O&M reduced cost	MNOK/yr		1 165	-	-	-	-	-	-	-	67	37	67	62	67	37	67	62	67	37	67	62
Power purchase	MNOK/yr	-	5 260	-	-	-	-	-	-	- -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	263 -	263 -
Total ABEX	MNOK/yr	-	975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sum cost	MNOK/yr	-	6 670	-	-	-	-	-	-	- -	276 -	306 -	276 -	281 -	276 -	306 -	276 -	281 -	276 -	306 -	276 -	281 -
Cash flow before tax (real)	MNOK/yr		7 529	-	-	- -	2 688 -	2 688 -	2 688 -	2 688	972	942	972	967	972	942	972	967	972	942	972	967
Tax (nom)	MNOK/yr	-	11 105	-	-	-	1 012	2 044	2 088	2 132	646 -	855 -	874 -	903 -	922 -	929 -	948 -	980 -	1 000 -	1 007 -	1 028 -	1 063 -
NOMINAL Cash flow before tax	**MNOK nom/yr**			**-**	**-**	**- -**	**2 853 -**	**2 910 -**	**2 968 -**	**3 027**	**1 116**	**1 103**	**1 161**	**1 178**	**1 208**	**1 194**	**1 257**	**1 275**	**1 308**	**1 293**	**1 360**	**1 380**
NOMINAL Cash flow after tax	**MNOK nom/yr**		**2 346**	**-**	**-**	**- -**	**1 841 -**	**866 -**	**880 -**	**895**	**1 762**	**248**	**288**	**275**	**286**	**265**	**309**	**295**	**307**	**285**	**332**	**318**
Cumulative cash flow	MNOK nom/yr			-	-	- -	1 841 -	2 706 -	3 586 -	4 482 -	2 719 -	2 472 -	2 184 -	1 909 -	1 623 -	1 358 -	1 049 -	754 -	447 -	161	171	488
Payback periode (months)				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	126	-

NET PRENSENT VALUE, IRR AND PAYBACK

NOMINAL		
%	MNOK	
Discount rate	NPV before tax	NPV After tax
1%	10 079	1 659
2%	7 381	1 100
3%	5 222	646
4%	3 493	279
5%	2 109	- 19
6%	1 003	- 259
7%	121	- 452
8%	- 581	- 606
9%	- 1 136	- 729
10%	- 1 573	- 825
IRR	7,16%	4,93%
Payback (months)		126







Abatement cost

Discount Rate	Abatement calc.
4%	1870,361117
7%	2812,047519

ABATEMENT COST

Discount rate 7%

				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Parameters (excl. CO2)			**NPV**																			
Delta capex	MNOK nom	-	8 113	-	-	- -	2 853 -	2 910 -	2 968 -	3 027	-	-	-	-	-	-	-	-	-	-	-	-
Delta opex	MNOK nom	-	192	-	-	-	-	-	-	- -	15 -	50 -	16 -	22 -	16 -	55 -	17 -	24 -	17 -	59 -	18 -	26 -
Gas sales	MNOK nom		4 369	-	-	-	-	-	-	-	569	581	592	604	616	629	641	654	667	681	694	708
Power purchase	MNOK nom	-	2 318	-	-	-	-	-	-	- -	302 -	308 -	314 -	321 -	327 -	334 -	340 -	347 -	354 -	361 -	368 -	376 -
Sum Cost befor tax (excl CO2)	MNOK nom		6 254																			
Sum Cost before tax (excl CO2) - NOK	MNOK nom		**6 254**																			
			NPV																			
NPV CO2 emissions (no eletrification)	Ton CO2		2 555 971	-	-	-	-	-	-	-	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76	387 419,76
NPV CO2 emissions (Eletrification)	Ton CO2		331 944	-	-	-	-	-	-	-	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25	50 314,25
Total CO2 reduction	**MTon CO2**		**2,224**																			

Abatement calcualtion **2 812,05** Nok/ton CO2

Appendix 2.3: *Draft of Excel Sheet Calculations – Tax Calculations*

Tax Calcualtions

				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Inflation													
Inflations adjusted for tax calculations				2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Inflation factor				1	1,02	1,04	1,06	1,08	1,10	1,13	1,15	1,17	1,20
Ordinary corporate tax (CT)													
Tax rate	22%		SUM										
Total revenues	MNOK nom/yr		34 818	-	-	-	-	-	-	-	1 433	1 462	1 491
Total costs	MNOK nom/yr	-	9 610	-	-	-	-	-	-	- -	317 -	358 -	330 -
Calculated revenues to onshore	MNOK nom/yr		-	-	-	-	-	-	-	-	-	-	-
Depreciation for CT	MNOK nom/yr	-	10 664	-	-	- -	2 587 -	2 639 -	2 692 -	2 746	-	-	-
Tax base for CT	MNOK nom/yr		14 545	-	-	- -	2 587 -	2 639 -	2 692 -	2 746	1 116	1 103	1 161
Tax liability	**MNOK nom/yr**		3 200	**-**	**-**	**- -**	**569 -**	**581 -**	**592 -**	**604**	**246**	**243**	**255**
Tax payment	**MNOK nom/yr**		3 200	**-**	**-**	**- -**	**285 -**	**575 -**	**586 -**	**598 -**	**179**	**244**	**249**
Special tax (SPT)													
Tax rate	71,8%												
Total revenues	MNOK nom/yr		34 818	-	-	-	-	-	-	-	1 433	1 462	1 491
Total costs	MNOK nom/yr	-	9 610	-	-	-	-	-	-	- -	317 -	358 -	330 -
Depreciation for SPT	MNOK nom/yr	-	10 664	-	-	- -	2 587 -	2 639 -	2 692 -	2 746	-	-	-
CT tax - for deduction against SPT	MNOK nom/yr	-	3 200	-	-	-	569	581	592	604 -	246 -	243 -	255 -
Tax base for SPT	MNOK nom/yr		11 345	-	-	- -	2 018 -	2 058 -	2 100 -	2 142	870	860	906
Tax liability	**MNOK nom/yr**		8 146	**-**	**-**	**- -**	**1 449 -**	**1 478 -**	**1 507 -**	**1 538**	**625**	**618**	**650**
Tax payment	**MNOK nom/yr**		8 146	**-**	**-**	**- -**	**724 -**	**1 463 -**	**1 493 -**	**1 523 -**	**456**	**621**	**634**
Onshore coporate tax calcualtions													
Tax rate	22%												
Onshore depreciation	MNOK nom/yr			-	-	- -	13 -	26 -	39 -	51 -	48 -	46 -	44 -
Tax base onshore	MNOK nom/yr			-	-	- -	13 -	26 -	39 -	51 -	48 -	46 -	44 -
Tax liability	**MNOK nom/yr**			**-**	**-**	**- -**	**3 -**	**6 -**	**8 -**	**11 -**	**11 -**	**10 -**	**10 -**
Tax payment	**MNOK nom/yr**			**-**	**-**	**- -**	**3 -**	**6 -**	**8 -**	**11 -**	**11 -**	**10 -**	**10 -**

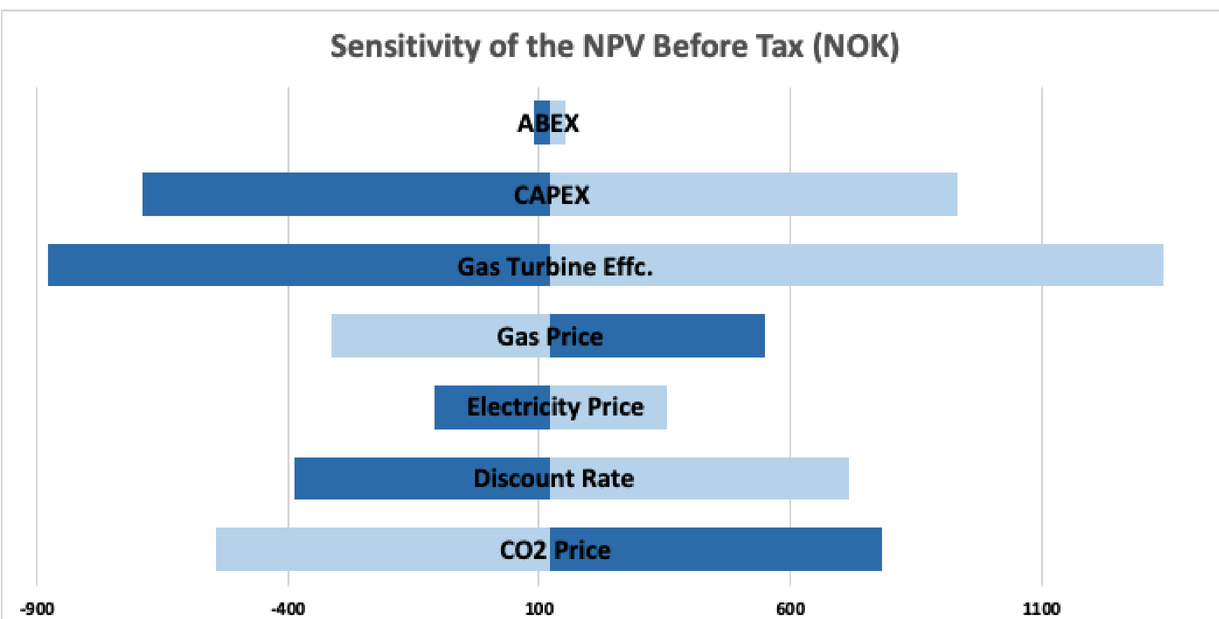
__Appendix 2.4:__ Draft of Excel Sheet Calculations – Tax Depreciation

Tax Depreciation		SUM										
Offshore tax depreciation												
Capex	MNOK nom	11 757	-	-	-	2 853	2 910	2 968	3 027	-	-
Capex allocated onshore (neg.)	MNOK nom	- 1 093	-	-	-	- 265	- 271	- 276	- 282	-	-
Total capex for offshore depreciation	MNOK nom	10 664	-	-	-	2 587	2 639	2 692	2 746	-	-
Depreciation for CT	MNOK nom	10 664	-	-	-	2 587	2 639	2 692	2 746	-	-
Depreciation for SPT	MNOK nom	10 664	-	-	-	2 587	2 639	2 692	2 746	-	-
Onshore tax depreciation											
Depreciation rate (asset group g)	5,0%										
Opening balance	MNOK nom		0	0	0	0	252	497	734	965	916
Capex allocated onshore	MNOK nom	1093	0	0	0	265	271	276	282	0	0
Declining balance depreciation	MNOK nom	1093	0	0	0	13	26	39	51	48	46
Closing tax balance	MNOK nom		0	0	0	252	497	734	965	916	871
Cumulative investments	MNOK nom		0	0	0	265	536	812	1093	1093	1093

^depreciation rate - Plant for transmission and distribution of electric power and electronic equipment in a power company (asset group g)

__Appendix 2.5:__ Excel Calculations - Sensitivity of the NPV

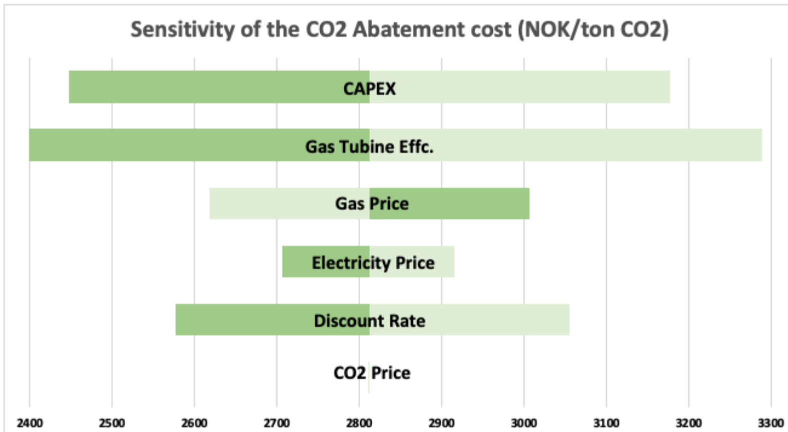
+- 10%	NPV Before Tax Sensitivity					
Discount rate 7 %	Used	-10%	10%		-10%	10%
CO2 Price	2230	2007,0	2453,0	CO2 Price	-542,00	783,00
Discount rate	7%	6,30%	7,70%	Discount rate	717,00	-387,00
Electricity Price	526	473,4	578,6	Electricity Price	355,00	-108,00
Gas price	3,44	3,10	3,78	Gas price	-313,00	551,00
Gas turbine effc.	30	27,0	33,0	Gas turbine effc.	1342,00	-879,00
	22	19,8	24,2	CAPEX	932	-691
CAPEX	10752	9677	11827	ABEX	151	89
ABEX	975	857	1098			



Appendix 2.6: *Excel Calculations - Sensitivity of the CO_2 Abatement*

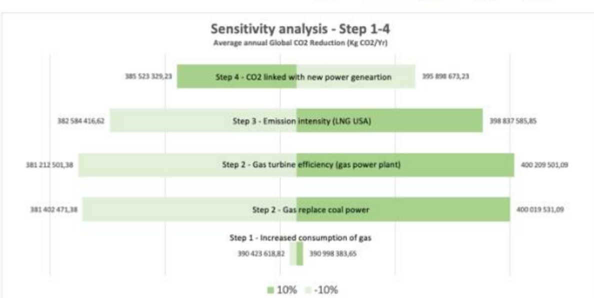
+- 10%			
Discount rate 7 %	Used	-10%	10%
CO2 Price	2230	2007	2453
Discount rate	7%	6,30%	7,70%
Electricity Price	526	473	579
Gas price	3,44	3,10	3,78
Gas turbine effc.	30	27	33
	22	19,8	24,2
CAPEX	10752	9676,8	11827,2

Abatement cost sensitivity			
	-10%	10%	Abatement cost
CO2 Price	2812,00	2812,00	2812,05
Discount rate	2577,46	3055,68	2812,05
Electricity Price	2705,86	2915,60	2812,05
Gas price	3006,95	2618,76	2812,05
Gas turbine effc.	2334,38	3289,71	2812,05
Capex	2447,24	3176,85	2812,05



Appendix 2.7: *Excel Calculations - Sensitivity of the Global CO_2 Reduction*

DATA				
Step 1 Variable		**Value**	**-10%**	**10%**
Increased consumption due to market effect of increased supply of gas to Europe		23%	20,7%	25,3%
Step 2 Variable	**Year**			
Increased share of gas replacing coal power	2030-2050	70%-50%	63%-45%	77%-55%
Assumed gas turbine efficiency (gas power plant)	2030-2050	49%	44%	54%
Step 3 Variable				
Avoided CO2 emissions from LNG gas from the USA				
Upstream intensity (LNG USA)		16,00	14,40	17,60
Midstream intensity (LNG USA)		65,00	58,50	71,50
Methane intensity (LNG USA)		27,00	24,30	29,70
Step 4 Variable	**Year**			
	2030	0,195	0,176	0,215
	2035	0,140	0,126	0,154
CO2 Emissions linked to new power generation for platform electrification	2040	0,080	0,072	0,088
	2045	0,045	0,041	0,050
	2050	0,010	0,009	0,011



SENSITIVITY RESULTS							
	Years	2030	2035	2040	2045	2050	
	0% (No change) -	350 485 338 -	373 081 629 -	398 437 321 -	409 996 013 -	421 554 705	kg CO2/yr
Step 1 Variable				**CO2 Reduction**			**Unit**
	-10% -	348 646 534 -	372 018 536 -	398 149 939 -	410 484 341 -	422 818 744	kg CO2/yr
	10% -	352 324 142 -	374 144 723 -	398 724 704 -	409 507 685 -	420 290 666	kg CO2/yr
Step 2 Variable				**CO2 Reduction**			**Unit**
1	-10% -	339 625 386 -	362 997 389 -	389 128 791 -	401 463 194 -	413 797 597	kg CO2/yr
2	10% -	361 345 289 -	383 165 870 -	407 745 851 -	418 528 832 -	429 311 813	kg CO2/yr
	-10% -	339 403 754 -	362 791 588 -	388 938 821 -	401 289 055 -	413 639 288	kg CO2/yr
	10% -	361 566 921 -	383 371 671 -	407 935 821 -	418 702 971 -	429 470 121	kg CO2/yr
Step 3 Variable				**CO2 Reduction**			**Unit**
	-10% -	342 358 753 -	364 955 045 -	390 310 737 -	401 869 428 -	413 428 120	kg CO2/yr
	10% -	358 611 922 -	381 208 214 -	406 563 906 -	418 122 598 -	429 681 289	kg CO2/yr
Step 4 Variable				**CO2 Reduction**			**Unit**
	-10% -	361 246 998 -	380 807 949 -	402 852 361 -	412 479 473 -	422 106 585	kg CO2/yr
	10% -	339 723 678 -	365 355 309 -	394 022 281 -	407 512 553 -	421 002 825	kg CO2/yr

	Average Global CO2 Reduction Annual		
	-10%	10%	Base
STEP 1	390 423 618,82	390 998 383,65	390 711 001
STEP 2	381 402 471,38	400 019 531,09	390 711 001
STEP 2	381 212 501,38	400 209 501,09	390 711 001
STEP 3	382 584 416,62	398 837 585,85	390 711 001
STEP 4	395 898 673,23	385 523 329,23	390 711 001

Global CO2 Impact Analysis

Appendix 2.8*: Excel Sheet Calculation: Global CO_2 Emission impact vs. National*

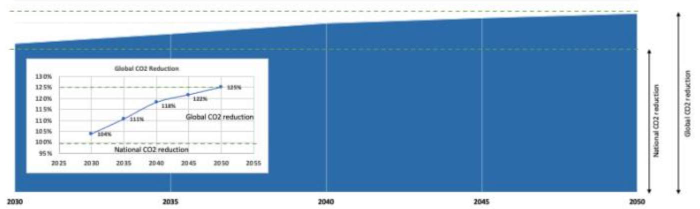
SUMMARY - ENVIRONMENTAL IMPACT ANALYSIS

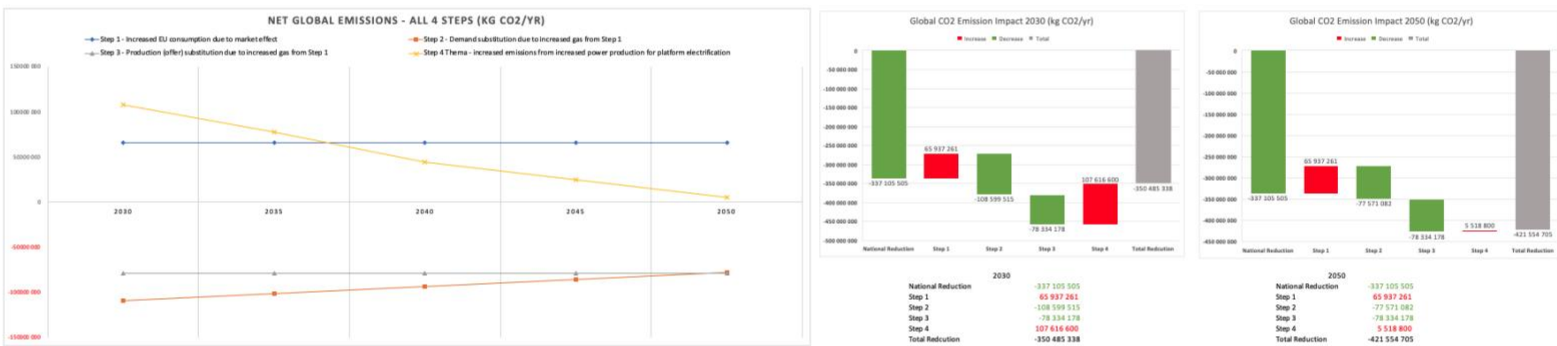
NETTO GLOBAL CO2 EMISSIONS - CALCUALTIONS

Comparison based on unit - kg CO2/boe	2030	2035	2040	2045	2050	
The zero alternative						
CO2 uslipp ungått på plattform pga elektrifisewring (Per boe økt gass til europa)	-345	-345	-345	-345	-345	kg CO2/boe (økt gass levert)
Rystad og Thema effekter						
Step 1 (market effect - increased gas power generation in Europe)	67	67	67	67	67	kg CO2/boe (gas supplied)
Stage 2 (demand effect - coal power substitution due to increased gas power production in Europe)	-111	-103	-95	-87	-79	kg CO2/boe (gas supplied)
Step 3 (supply effect - increased gas substitution of LNG from the US)	-80	-80	-80	-80	-80	kg CO2/boe (gas supplied)
Step 4 (power market effect - increased power production due to electrification of platform)	110	79	45	25	6	kg CO2/boe (gas supplied)
Sum effekter i gass marked og kraftmarked	-14	-37	-63	-75	-86	kg CO2/boe (gas supplied)

Global CO2 Emissions (kg CO2/year)	2030	2035	2040	2045	2050	
Electrification						
CO2 emissions reduced due to electrification -National CO2 reduction	-337 105 505	-337 105 505	-337 105 505	-337 105 505	-337 105 505	kg CO2/yr
Calcualted Global netto CO2 Emission						
Step 1 - Increased EU consumption due to market effect	65 937 261	65 937 261	65 937 261	65 937 261	65 937 261	kg CO2/yr
Step 2 - Demand substitution due to increased gas from Step 1	-108 599 515	-100 842 407	-93 085 299	-85 328 190	-77 571 082	kg CO2/yr
Step 3 - Production (offer) substitution due to increased gas from Step 1	-78 334 178	-78 334 178	-78 334 178	-78 334 178	-78 334 178	kg CO2/yr
Step 4 Thema - increased emissions from increased power production for platform electrification	107 616 600	77 263 200	44 150 400	24 834 600	5 518 800	kg CO2/yr
Total effects in the gas market and power market	-13 379 832	-35 976 124	-61 331 816	-72 890 508	-84 449 199	kg CO2/yr
Global netto CO2 emissions due to electrification, gas market effects and power market effects	-350 485 338	-373 081 629	-398 437 321	-409 996 013	-421 554 705	kg CO2/yr
Global netto emissions due to electrification, gas market effects and power market effects vs national	104%	111%	118%	122%	125%	

	2030	2035	2040	2045	2050
National & Global CO2 Reductio	350 485 338	373 081 629	398 437 321	409 996 013	421 554 705





Appendix 2.9*: Excel Sheet Calculation: Step 1 – Increased EU consumption due to market effect*

The zero alternative - CO2 Emissions from turbines without electrification

	Sum	Jotun A	Ringhorne	Grane	
CO2 Emission factor for assumed gas (2,34 Kg CO2/Sm3)	344,96	344,96	344,96	344,96	kg CO2/boe
Fuel gas consumption (turbin)		499 145	89 133	534 799	boe/yr
CO2 Emission from turbines	387 419 760	172 186 560	30 747 600	184 485 600	kg CO2/yr

Step 1 - Increased EU consumption due to market effect

Increased consumption due to market effect of increased supply of gas to Europe	23,00%	
CO2 Emission factor for assumed gas (1,99 Kg CO2/Sm3)	293,37	kg CO2/boe
Unit effect	67,47	kg CO2/boe

Absolute effect of increased gas from Norway - step 1	Sum	Jotun A	Ringhorne	Grane	
Increased gas to Europe		353 291	89 133	534 799	boe/yr
CO2 emissions associated with the gas to Europe		103 643 542	26 148 600	156 891 600	kg CO2/yr
Increased emissions due to 23% market effect	65 937 261	23 838 015	6 014 178	36 085 068	kg CO2/yr

***Appendix 2.10**: Excel Sheet Calculation: Step 2 – Demand substitution due to increased gas from Step 1*

Step 2 - Demand substitution due to increased gas from Step 1	2030	2035	2040	2045	2050	
Increased share of gas replacing coal power	70%	65%	60%	55%	50%	
Increased share of gas replacing renewable power	30%	35%	40%	45%	50%	
Assumed gas turbine efficiency (gas power plant)	49%	49%	49%	49%	49%	
Energy content in 1 boe gas to power	1 638	1 638	1 638	1 638	1 638	kWh/boe
Electricity production from 1 boe of gas	803	803	803	803	803	kWh
Gas power for 1 boe replacing coal	803	803	803	803	803	kWh/boe (gas supplied)
CO2 Emission factor coal power	0,86	0,86	0,86	0,86	0,86	kg CO2/kWh
Avoided CO2 emissions from coal for 1 boe of gas	690	690	690	690	690	kg CO2/boe (gas supplied
Adjusted for the share of increased gas that replaces coal (70-50%)	483	449	414	380	345	kg CO2/boe (gas supplied
Adjusted for the share of increased gas from Norway that results in increased gas consumption	**111**	**103**	**95**	**87**	**79**	kg CO2/boe (gas supplied
Avoided CO2 emissions for 1 boe supplied to Europe due to substitution of coal	- 111	- 103	- 95	- 87	- 79	kg CO2/boe (unit)

Jotun A - Step 2	2030	2035	2040	2045	2050	
Increased gas to Europe	353 291 boe/yr					
Reduced CO2 emissions due to the substitution of coal	-39 261 516	-36 457 122	-33 652 728	-30 848 334	-28 043 940	kg CO2/yr
Ringehorne - Step 2						
Increased gas to Europe	89 133 boe/yr					
Reduced CO2 emissions due to the substitution of coal	-9 905 428	-9 197 898	-8 490 367	-7 782 837	-7 075 306	kg CO2/yr
Grane - Step 2						
Increased gas to Europe	534 799 boe/yr					
Reduced CO2 emissions due to the substitution of coal	-59 432 570	-55 187 387	-50 942 203	-46 697 020	-42 451 836	kg CO2/yr
SUM	-108 599 515	-100 842 407	-93 085 299	-85 328 190	-77 571 082	kg CO2/yr

***Appendix 2.11**: Excel Sheet Calculation: Step 3 – Supply substitution due to increased gas from Step 1*

Step 3 - Supply substitution due to increased gas from Step 1		
Share of increased gas supply to Europe displacing LNG from the USA	77,00%	
Avoided CO2 emissions from LNG gas from the USA		
Upstream intensity (LNG USA)	16,00	kg CO2/boe
Midstream intensity (LNG USA)	65,00	kg CO2/boe
Methane intensity (LNG USA)	27,00	kg CO2/boe
Total avoided CO2 emissions from LNG gas from the USA	108,00	kg CO2/boe (gas supplied)
Adjusted: avoided CO2 emissions from LNG gas from the USA share displaced (77%)	83,16	kg CO2/boe (gas supplied)
Increased CO2 emissions from increased gas supplied to Europe from Norway		
Upstream Intensity platform electrified	-	kg CO2/boe
Midstream intensity	3,00	kg CO2/boe
Methane intensity	-	kg CO2/boe
Total increased CO2 emissions from increased gas supplied to Europe from Norway	3,00	kg CO2/boe (gas supplied)
Avoided CO2 emissions from substitution of LNG from the USA	**80,16**	kg CO2/boe (gas supplied)

Absolute effect of increased gas from Norway - step 3					
Increased gas to Europe		353 291	89 133	534 799	boe/yr
Avoided CO2 emissions from substitution of LNG from the USA (reduced)		-80,16	-80,16	-80,16	kg CO2/boe (unit)
Reduced CO2 emissions due supply substitution in the gas market	- 78 334 178	- 28 319 819	- 7 144 908	- 42 869 451	kg CO2/yr

***Appendix 2.12**: Excel Sheet Step 4 – Increased emissions from increased power production for platform electrification*

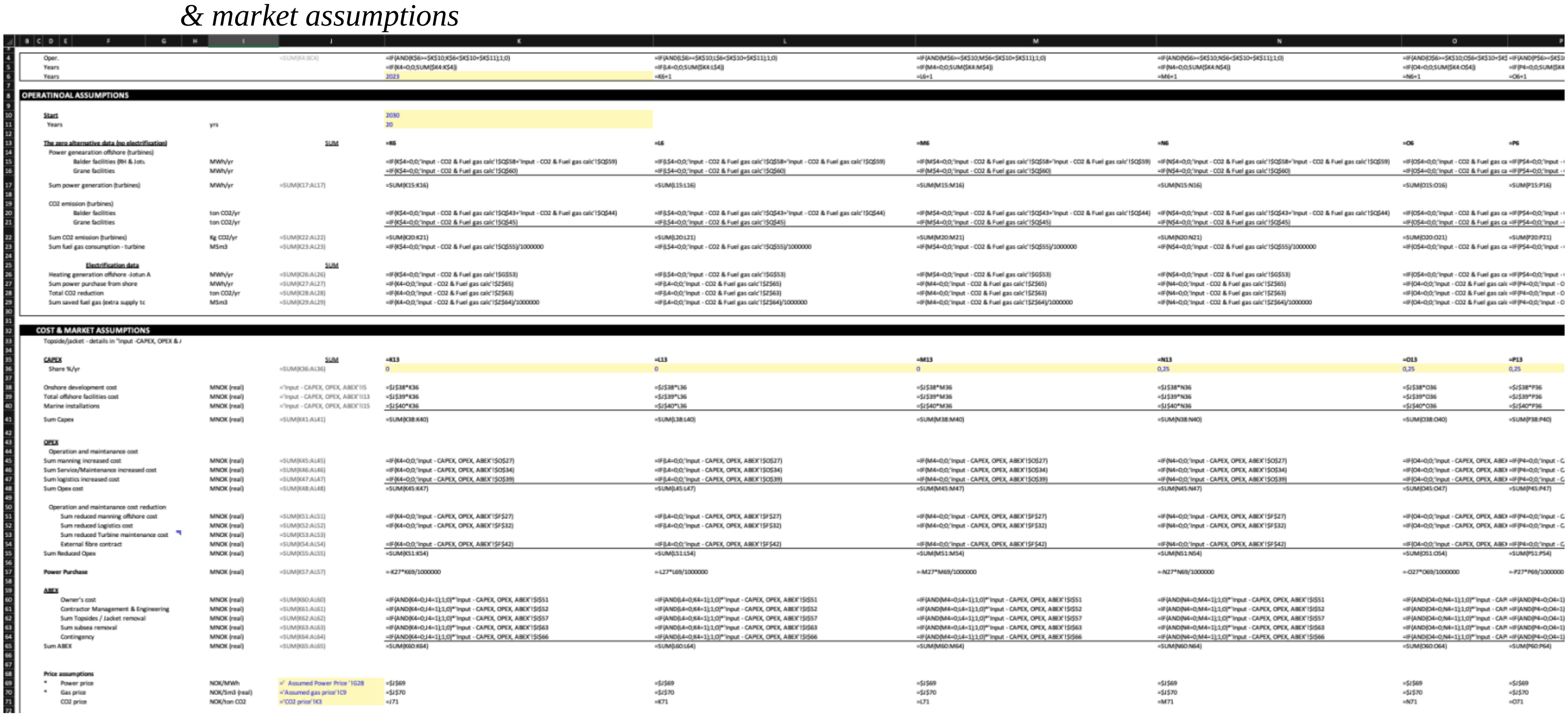
Step 4 Thema - increased emissions from increased power production for platform electrification

	2030	2035	2040	2045	2050	
CO_2 Emissions linked to new power generation for platform electrification	0,195	0,140	0,080	0,045	0,010	t CO_2/MWh el
CO_2 Emissions linked to new power generation for platform electrification	319	229	131	74	16	kg CO_2/boe el
Jotun A - Absolute effect from new power generation - step 4 (Thema)						
Increased gas to Europe	353 291					boe/yr
CO_2 emissions associated with new power generation for electrification	135	97	56	31	7	kg CO_2/boe (units)
Increased CO_2 emissions associated with new power generation for electrification	47 829 600	34 339 200	19 622 400	11 037 600	2 452 800	kg CO_2/yr
Ringehorne - Absolute effect from new power generation - step 4 (Thema)						
Increased gas to Europe	89 133					boe/yr
CO_2 emissions associated with new power generation for electrification	96	69	39	22	5	kg CO_2/boe (increased gas)
Increased CO_2 emissions associated with new power generation for electrification	8 541 000	6 132 000	3 504 000	1 971 000	438 000	kg CO_2/yr
Grane - Absolute effect from new power generation - step 4 (Thema)						
Increased gas to Europe	534 799					boe/yr
CO_2 emissions associated with new power generation for electrification	96	69	39	22	5	kg CO_2/boe (increased gas)
Increased CO_2 emissions associated with new power generation for electrification	51 246 000	36 792 000	21 024 000	11 826 000	2 628 000	kg CO_2/yr
Average	110	79	45	25	6	kg CO_2/boe (units)
SUM	**107 616 600**	**77 263 200**	**44 150 400**	**24 834 600**	**5 518 800**	kg CO_2/yr

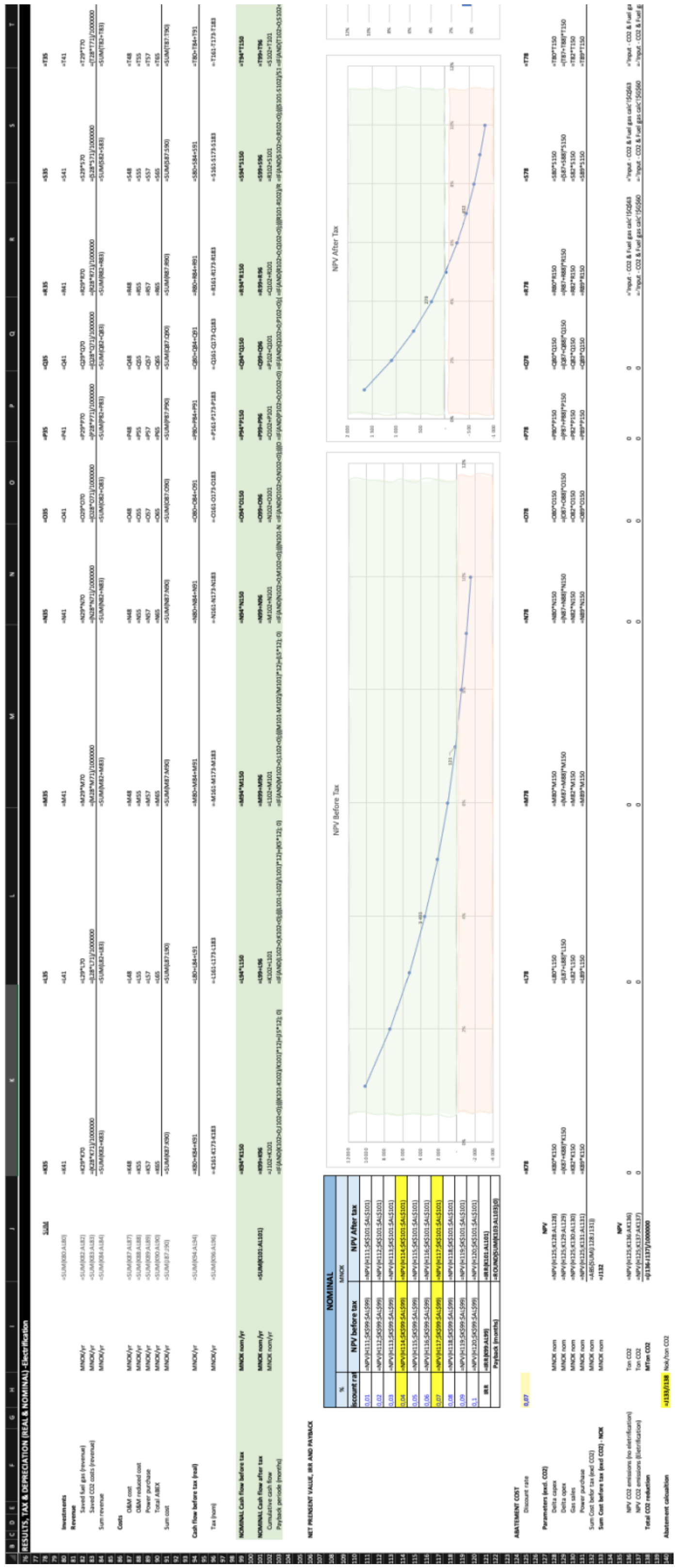
Appendix 3 – "Show Formulas" in Excel

Economic analyses

***Appendix 3.1**: Formulas & Calculations draft – Operational data, Cost (CapEx, OpEx, ABEX) & market assumptions*



Appendix 3.2*: Formulas & Calculations draft -Results, cashflow, abatement cost, NPV, IRR, Payback period, nominal and real.*



__Appendix 3.3__: Formulas & Calculations draft – Tax & depreciation

	C–H	I	J	K	L	M	N	O	P	Q	R	S
145												
146	**Tax Calcualtions**											
147				**=K78**	**=L78**	**=M78**	**=N78**	**=O78**	**=P78**	**=Q78**	**=R78**	**=S78**
148	Inflation											
149	Inflations adjusted for tax calculation			0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
150	Inflation factor			1	=K150*(1+L149)	=L150*(1+M149)	=M150*(1+N149)	=N150*(1+O149)	=O150*(1+P149)	=P150*(1+Q149)	=Q150*(1+R149)	=R150
151												
152	**Ordinary corporate tax (CT)**											
153	Tax rate	**0,22**	SUM									
154	Total revenues	MNOK nom/yr	=SUM(K154:AL154)	=K84*K150	=L84*L150	=M84*M150	=N84*N150	=O84*O150	=P84*P150	=Q84*Q150	=R84*R150	=S84*
155	Total costs	MNOK nom/yr	=SUM(K155:AL155)	=K91*K150	=L91*L150	=M91*M150	=N91*N150	=O91*O150	=P91*P150	=Q91*Q150	=R91*R150	=S91*
156	Calculated revenues to onshore	MNOK nom/yr	=SUM(K156:AL156)	=-K178	=-L178	=-M178	=-N178	=-O178	=-P178	=-Q178	=-R178	=-S178
157	Depreciation for CT	MNOK nom/yr	=SUM(K157:AL157)	=-K194	=-L194	=-M194	=-N194	=-O194	=-P194	=-Q194	=-R194	=-S194
158	Tax base for CT	MNOK nom/yr	=SUM(K158:AL158)	=SUM(K154:K157)	=SUM(L154:L157)	=SUM(M154:M157)	=SUM(N154:N157)	=SUM(O154:O157)	=SUM(P154:P157)	=SUM(Q154:Q157)	=SUM(R154:R157)	=SUM(
159												
160	**Tax liability**	**MNOK nom/yr**	=SUM(K160:AL160)	**=K158*$I$153**	**=L158*$I$153**	**=M158*$I$153**	**=N158*$I$153**	**=O158*$I$153**	**=P158*$I$153**	**=Q158*$I$153**	**=R158*$I$153**	**=S158**
161	**Tax payment**	**MNOK nom/yr**	=SUM(K161:AL161)	**=K160/2**	**=K160/2+L160/2**	**=L160/2+M160/2**	**=M160/2+N160/2**	**=N160/2+O160/2**	**=O160/2+P160/2**	**=P160/2+Q160/2**	**=Q160/2+R160/2**	**=R160**
162												
163												
164	**Special tax (SPT)**											
165	Tax rate	**0,718**										
166	Total revenues	MNOK nom/yr	=SUM(K166:AL166)	=K154	=L154	=M154	=N154	=O154	=P154	=Q154	=R154	=S154
167	Total costs	MNOK nom/yr	=SUM(K167:AL167)	=K155	=L155	=M155	=N155	=O155	=P155	=Q155	=R155	=S155
168	Depreciation for SPT	MNOK nom/yr	=SUM(K168:AL168)	=-K195	=-L195	=-M195	=-N195	=-O195	=-P195	=-Q195	=-R195	=-S195
169	CT tax - for deduction against SPT	MNOK nom/yr	=SUM(K169:AL169)	=-K160	=-L160	=-M160	=-N160	=-O160	=-P160	=-Q160	=-R160	=-S160
170	Tax base for SPT	MNOK nom/yr	=SUM(K170:AL170)	=SUM(K166:K169)	=SUM(L166:L169)	=SUM(M166:M169)	=SUM(N166:N169)	=SUM(O166:O169)	=SUM(P166:P169)	=SUM(Q166:Q169)	=SUM(R166:R169)	=SUM(
171												
172	**Tax liability**	**MNOK nom/yr**	=SUM(K172:AL172)	**=K170*$I$165**	**=L170*$I$165**	**=M170*$I$165**	**=N170*$I$165**	**=O170*$I$165**	**=P170*$I$165**	**=Q170*$I$165**	**=R170*$I$165**	**=S170**
173	**Tax payment**	**MNOK nom/yr**	=SUM(K173:AL173)	**=K172/2**	**=K172/2+L172/2**	**=L172/2+M172/2**	**=M172/2+N172/2**	**=N172/2+O172/2**	**=O172/2+P172/2**	**=P172/2+Q172/2**	**=Q172/2+R172/2**	**=R172**
174												
175												
176												
177	**Onshore coporate tax calcualtions**											
178	Tax rate	**0,22**										
179	Onshore depreciation	MNOK nom/yr		=-K201	=-L201	=-M201	=-N201	=-O201	=-P201	=-Q201	=-R201	=-S201
180	Tax base onshore	MNOK nom/yr		=SUM(K178:K179)	=SUM(L178:L179)	=SUM(M178:M179)	=SUM(N178:N179)	=SUM(O178:O179)	=SUM(P178:P179)	=SUM(Q178:Q179)	=SUM(R178:R179)	=SUM(
181												
182	**Tax liability**	**MNOK nom/yr**		**=K180*$I$178**	**=L180*$I$178**	**=M180*$I$178**	**=N180*$I$178**	**=O180*$I$178**	**=P180*$I$178**	**=Q180*$I$178**	**=R180*$I$178**	**=S180**
183	**Tax payment**	**MNOK nom/yr**		**=K182**	**=L182**	**=M182**	**=N182**	**=O182**	**=P182**	**=Q182**	**=R182**	**=S182**
184												
185												
186												
187	**Tax Depreciation**											
188												
189	**Offshore tax depreciation**		SUM									
190	Capex	MNOK nom	=SUM(K190:AL190)	=-K80*K150	=-L80*L150	=-M80*M150	=-N80*N150	=-O80*O150	=-P80*P150	=-Q80*Q150	=-R80*R150	=-S80*
191	Capex allocated onshore (neg.)	MNOK nom	=SUM(K191:AL191)	=K38*K150	=L38*L150	=M38*M150	=N38*N150	=O38*O150	=P38*P150	=Q38*Q150	=R38*R150	=S38*
192	Total capex for offshore depreciation	MNOK nom	=SUM(K192:AL192)	=SUM(K190:K191)	=SUM(L190:L191)	=SUM(M190:M191)	=SUM(N190:N191)	=SUM(O190:O191)	=SUM(P190:P191)	=SUM(Q190:Q191)	=SUM(R190:R191)	=SUM(
193												
194	Depreciation for CT	MNOK nom	=SUM(K194:AL194)	=K192	=L192	=M192	=N192	=O192	=P192	=Q192	=R192	=S192
195	Depreciation for SPT	MNOK nom	=SUM(K195:AL195)	=K192	=L192	=M192	=N192	=O192	=P192	=Q192	=R192	=S192
196												
197	**Onshore tax depreciation**											
198	Depreciation rate (asset group g)	**0,05**										
199	Opening balance	MNOK nom		=J202	=K202	=L202	=M202	=N202	=O202	=P202	=Q202	=R202
200	Capex allocated onshore	MNOK nom	=SUM(K200:AL200)	=-K191	=-L191	=-M191	=-N191	=-O191	=-P191	=-Q191	=-R191	=-S191
201	Declining balance depreciation	MNOK nom	=SUM(K201:AL201)	=K200*I198	=(L199+L200)*$I$198	=(M199+M200)*$I$198	=(N199+N200)*$I$198	=(O199+O200)*$I$198	=(P199+P200)*$I$198	=(Q199+Q200)*$I$198	=(R199+R200)*$I$198	=(S199
202	Closing tax balance	MNOK nom		=J202+K200-K201	=K202+L200-L201	=L202+M200-M201	=M202+N200-N201	=N202+O200-O201	=O202+P200-P201	=P202+Q200-Q201	=Q202+R200-R201	=R202-
203	Cumulative investments	MNOK nom		=K200+J203	=L200+K203	=M200+L203	=N200+M203	=O200+N203	=P200+O203	=Q200+P203	=R200+Q203	=S200
204												
205	^deprecation rate - Plant for transmission and distribution of electric power and e											

Global CO2 Impact Analysis

__Appendix 3.4__: CO_2, Fuel gas consumption and power need – Formulas used to calculate Jotun FPSO, Ringhorne and Grane (same method use for all facilities) – further used in STEP 1-4 Calculations

	B–C	D	G	H
2	**BALDER/GRANE ELECTRIFICATION - CO2 EMISSION (TON CO2) & FUEL GAS (SM3)**			
3	*ASSUMPTIONS AND CALCULATIONS			
4				
5	**JOTUN A - NO ELECTRIFICATION/ELECTRIFICATION**			
6	**Fuel gas**	Source: SSB	**2,34**	**ton CO2/1000 Sm3**
7	**Fuel gas**		=G6	kg CO2/Sm3
9	**Fuel gas**		=G7*1000/G15	g CO2/kWh
10	**Fuel gas**		**=G12*G9/(1000)**	**kg CO2/boe**
12	1 boe		1638	kWh
13	1 kWh		3,6	MJ
14	1 SM3		40	MJ
15	1 SM3		=G14/G13	kWh
17	**Jotun A - Calculation assumptions, Gas use/saved, CO2 Emission & Electrification**			
19	Power generation		28	MW
20	Hours/yr		8760	
21	Availability of power turbines		1	
22	Power production per year		=G21*G20*G19	MWh/yr
23				
24	Turbine efficiency		0,3	
25	Fuel gas consumption (turbin)		=G22/G24	MWh/yr
26	Fuel gas consumption (turbin)		=G25*1000/G12	boe/yr
27				
28	Emission from turbines		=G26*G10	kg CO2/yr
29	Emission from turbines		=G28/1000	ton CO2/yr
30				
31	Reduced emissions due to electrification			
32	**100% eletrification**		**=G29**	**ton CO2/yr**
33	**Extra gas - export (fuel gas)**		**=(G29*1000)/G7**	**Sm3**
34				

Appendix 3.5: *The Zero Alternative and Step 1 Formulas - CO_2 Calculations*

	A	B	C	D	E	H	I	J	K	
2		**The zero alternative - CO2 Emissions from turbines without electrification**								
3						Sum	**Jotun A**	**Ringhorne**	**Grane**	
4		CO2 Emission factor for assumed gas (2,34 Kg CO2/Sm3)				=AVERAGE(I4:K4)	**='Input - CO2 & fuel gas calc'!G10**	**='Input - CO2 & fuel gas calc'!P10**	**='Input - CO2 & fuel gas calc'!Y10**	kg CO2/boe
5		Fuel gas consumption (turbin)					='Input - CO2 & fuel gas calc'!G26	='Input - CO2 & fuel gas calc'!P26	='Input - CO2 & fuel gas calc'!Y26	boe/yr
6		CO2 Emission from turbines				=SUM(I6:K6)	**=I5*I4**	**=J5*J4**	**=K5*K4**	kg CO2/yr
7										
8		**Step 1 - Increased EU consumption due to market effect**								
9										
10		Increased consumption due to market effect of increased supply of gas to Europe					**0,253**			
11		CO2 Emission factor for assumed gas (1,99 Kg CO2/Sm3)					='Input - CO2 & fuel gas calc'!$O$45	kg CO2/boe		
12		Unit effect					**=I11*$I$10**	kg CO2/boe		
13										
14		**Absolute effect of increased gas from Norway - step 1**								
15		Increased gas to Europe					='Input - CO2 & fuel gas calc'!G26-'Input - CO2 & fue	=J5	=K5	boe/yr
16		CO2 emissions associated with the gas to Europe					=I15*$I$11	=J15*$I$11	=K15*$I$11	kg CO2/yr
17		Increased emissions due to 23% market effect				=SUM(I17:K17)	**=I16*$I$10**	**=J16*$I$10**	**=K16*$I$10**	kg CO2/yr
18										

Appendix 3.6: *Step 2 Formulas - CO_2 Calculations*

	B	C	D	E	H	I	J	K	L	M	N
19	**Step 2 - Demand substitution due to increased gas from Step 1**										
20						2030	2035	2040	2045	2050	
21	Increased share of gas replacing coal power					**0,7**	**0,65**	**0,6**	**0,55**	**0,5**	
22	Increased share of gas replacing renewable power					=1-I21	=1-J21	=1-K21	=1-L21	=1-M21	
23											
24	Assumed gas turbine efficiency (gas power plant)					**0,49**	**0,49**	**0,49**	**0,49**	**0,49**	
25	Energy content in 1 boe gas to power					='Input - CO2 & fuel gas calc'!$G$12	='Input - CO2 & fuel gas calc'!$G$12	='Input - CO2 & fuel gas calc'!$G$12	='Input - CO2 & fuel gas calc'!$G$12	='Input - CO2 & fuel gas calc'!$G$12	kWh/boe
26	Electricity production from 1 boe of gas					=$I$25*I24	=$I$25*J24	=$I$25*K24	=$I$25*L24	=$I$25*M24	kWh
27											
28	Gas power for 1 boe replacing coal					=I26	=J26	=K26	=L26	=M26	kWh/boe (gas supplied)
29	CO2 Emission factor coal power					**0,86**	**0,86**	**0,86**	**0,86**	**0,86**	kg CO2/kWh
30	Avoided CO2 emissions from coal for 1 boe of gas					=I29*I28	=J29*J28	=K29*K28	=L29*L28	=M29*M28	kg CO2/boe (gas supplied)
31	Adjusted for the share of increased gas that replaces coal (70-50%)					=I30*I21	=J30*J21	=K30*K21	=L30*L21	=M30*M21	kg CO2/boe (gas supplied)
32	Adjusted for the share of increased gas from Norway that results in increased gas consumption					**=I31*$I$10**	**=J31*$I$10**	**=K31*$I$10**	**=L31*$I$10**	**=M31*$I$10**	kg CO2/boe (gas supplied)
33	Avoided CO2 emissions for 1 boe supplied to Europe due to substitution of coal					=-$I$32	=-J32	=-K32	=-L32	=-$M$32	kg CO2/boe (unit)
34											
35											
36	**Jotun A - Step 2**					2030	2035	2040	2045	2050	
37	Increased gas to Europe					=I15	boe/yr				
38	Reduced CO2 emissions due to the substitution of coal					=$I$37*I33	=$I$37*J33	=$I$37*K33	=$I$37*L33	=$I$37*M33	kg CO2/yr
39											
40	**Ringehorne - Step 2**										
41	Increased gas to Europe					=J15	boe/yr				
42	Reduced CO2 emissions due to the substitution of coal					=$I$41*I33	=$I$41*J33	=$I$41*K33	=$I$41*L33	=$I$41*M33	kg CO2/yr
43											
44	**Grane - Step 2**										
45	Increased gas to Europe					=K15	boe/yr				
46	Reduced CO2 emissions due to the substitution of coal					=$I$45*I33	=$I$45*J33	=$I$45*K33	=$I$45*L33	=$I$45*M33	kg CO2/yr
47											
48											
49					**SUM**	=I38+I42+I46	=J38+J42+J46	=K38+K42+K46	=L38+L42+L46	=M38+M42+M46	kg CO2/yr
50											

Appendix 3.7: *Step 3 Formulas - CO_2 Calculations*

	A	B	C	D	E	H	I	J	K	L
53		**Step 3 - Supply substitution due to increased gas from Step 1**								
54										
55		Share of increased gas supply to Europe displacing LNG from the USA					=1-I10			
56		Avoided CO2 emissions from LNG gas from the USA								
57		Upstream intensity (LNG USA)					16	kg CO2/boe		
58		Midstream intensity (LNG USA)					65	kg CO2/boe		
59		Methane intensity (LNG USA)					27	kg CO2/boe		
60		Total avoided CO2 emissions from LNG gas from the USA					=SUM(I57:I59)	kg CO2/boe (gas supplied)		
61		Adjusted: avoided CO2 emissions from LNG gas from the USA share displaced (77%)					=I60*I55	kg CO2/boe (gas supplied)		
62										
63		Increased CO2 emissions from increased gas supplied to Europe from Norway								
64		Upstream Intensity platform electrified					0	kg CO2/boe		
65		Midstream intensity					3	kg CO2/boe		
66		Methane intensity					0	kg CO2/boe		
67		Total increased CO2 emissions from increased gas supplied to Europe from Norway					=SUM(I64:I66)	kg CO2/boe (gas supplied)		
68		Avoided CO2 emissions from substitution of LNG from the USA					**=I61-I67**	kg CO2/boe (gas supplied)		
69										
70		**Absolute effect of increased gas from Norway - step 3**								
71		Increased gas to Europe					=I15	=J5	=K5	boe/yr
72		Avoided CO2 emissions from substitution of LNG from the USA (reduced)					=-$I$68	=-$I$68	=-$I$68	kg CO2/boe (unit)
73		Reduced CO2 emissions due supply substitution in the gas market				=SUM(I73:K73)	**=I72*I71**	**=J72*J71**	**=K72*K71**	kg CO2/yr
74										

Appendix 3.8: *Step 4 - CO_2 Calculations*

	A	B	C	D	E	H	I	J	K	L	M	N
75		**Step 4 Thema - increased emissions from increased power production for**										
76												
77							**2030**	**=I77+5**	**=J77+5**	**=K77+5**	**=L77+5**	
78		CO2 Emissions linked to new power generation for platform electrification					0,195	0,14	0,08	0,045	0,01	t CO2/MWh el
79		CO2 Emissions linked to new power generation for platform electrification					=I78*'Input - CO2 & fuel gas calc'!$O$48	=J78*'Input - CO2 & fuel gas calc'!$O$48	=K78*'Input - CO2 & fuel gas calc'!$O$48	=L78*'Input - CO2 & fuel gas calc'!$O$48	=M78*'Input - CO2 & fuel gas calc'!$O$48	kg CO2/boe el
80												
81												
82		**Jotun A - Absolute effect from new power generation - step 4 (Thema)**										
83		Increased gas to Europe					='Step 1-4 CO2 Calculations'!I71					boe/yr
84		CO2 emissions associated with new power generation for electrification					=I85/$I$83	=J85/$I$83	=K85/$I$83	=L85/$I$83	=M85/$I$83	kg CO2/boe (units)
85		Increased CO2 emissions associated with new power generation for electrification					=I78*1000*'Input - CO2 & fuel gas calc'!$G$22	=J78*1000*'Input - CO2 & fuel gas calc'!$G$22	=K78*1000*'Input - CO2 & fuel gas calc'!$G$22	=L78*1000*'Input - CO2 & fuel gas calc'!$G$22	=M78*1000*'Input - CO2 & fuel gas calc'!$G$22	kg CO2/yr
86												
87		**Ringehorne - Absolute effect from new power generation - step 4 (Thema)**										
88		Increased gas to Europe					='Input - CO2 & fuel gas calc'!P26					boe/yr
89		CO2 emissions associated with new power generation for electrification					=I90/$I$88	=J90/$I$88	=K90/$I$88	=L90/$I$88	=M90/$I$88	kg CO2/boe (increased gas)
90		Increased CO2 emissions associated with new power generation for electrification					=I78*1000*'Input - CO2 & fuel gas calc'!$P$22	=J78*1000*'Input - CO2 & fuel gas calc'!$P$22	=K78*1000*'Input - CO2 & fuel gas calc'!$P$22	=L78*1000*'Input - CO2 & fuel gas calc'!$P$22	=M78*1000*'Input - CO2 & fuel gas calc'!$P$22	kg CO2/yr
91												
92		**Grane - Absolute effect from new power generation - step 4 (Thema)**										
93		Increased gas to Europe					='Input - CO2 & fuel gas calc'!Y26					boe/yr
94		CO2 emissions associated with new power generation for electrification					=I95/$I$93	=J95/$I$93	=K95/$I$93	=L95/$I$93	=M95/$I$93	kg CO2/boe (increased gas)
95		Increased CO2 emissions associated with new power generation for electrification					=I78*1000*'Input - CO2 & fuel gas calc'!$Y$22	=J78*1000*'Input - CO2 & fuel gas calc'!$Y$22	=K78*1000*'Input - CO2 & fuel gas calc'!$Y$22	=L78*1000*'Input - CO2 & fuel gas calc'!$Y$22	=M78*1000*'Input - CO2 & fuel gas calc'!$Y$22	kg CO2/yr
96												
97						Average	**=I98/($I$93+$I$88+$I$83)**	**=J98/($I$93+$I$88+$I$83)**	**=K98/($I$93+$I$88+$I$83)**	**=L98/($I$93+$I$88+$I$83)**	**=M98/($I$93+$I$88+$I$83)**	kg CO2/boe (units)
98						SUM	**=I85+I90+I95**	**=J85+J90+J95**	**=K85+K90+K95**	**=L85+L90+L95**	**=M85+M90+M95**	kg CO2/yr
99												

Appendix 3.9: *Results and charts – CO_2 Calculations Summary*

	B–E	J	K	L	M	N	O
2	SUMMARY - ENVIRONMENTAL IMPACT ANALYSIS						
3	NETTO GLOBAL CO2 EMISSIONS - CALCUALTIONS						
4							
5	**Comparison based on unit - kg CO2/boe**	**2030**	**=J5+5**	**=K5+5**	**=L5+5**	**=M5+5**	
6	The zero alternative						
7	CO2 uslipp ungått på plattform pga elektrifisewring (Per boe økt gass til europa)	=-'Step 1-4 CO2 Calculations'!$H$4	=-'Step 1-4 CO2 Calculations'!$H$4	=-'Step 1-4 CO2 Calculations'!$H$4	=-'Step 1-4 CO2 Calculations'!$H$4	=-'Step 1-4 CO2 Calculations'!$H$4	kg CO2/boe (økt gass levert)
8							
9	Rystad og Thema effekter						
10	Step 1 (market effect - increased gas power generation in Europe)	='Step 1-4 CO2 Calculations'!$I$12	='Step 1-4 CO2 Calculations'!$I$12	='Step 1-4 CO2 Calculations'!$I$12	='Step 1-4 CO2 Calculations'!$I$12	='Step 1-4 CO2 Calculations'!$I$12	kg CO2/boe (gas supplied)
11	Stage 2 (demand effect - coal power substitution due to increased gas power production in Europe)	='Step 1-4 CO2 Calculations'!I33	='Step 1-4 CO2 Calculations'!J33	='Step 1-4 CO2 Calculations'!K33	='Step 1-4 CO2 Calculations'!L33	='Step 1-4 CO2 Calculations'!M33	kg CO2/boe (gas supplied)
12	Step 3 (supply effect - increased gas substitution of LNG from the US)	=-'Step 1-4 CO2 Calculations'!$I$68	=-'Step 1-4 CO2 Calculations'!$I$68	=-'Step 1-4 CO2 Calculations'!$I$6	=-'Step 1-4 CO2 Calculations'!$I$68	=-'Step 1-4 CO2 Calculations'!$I$68	kg CO2/boe (gas supplied)
13	Step 4 (power market effect - increased power production due to electrification of platform)	='Step 1-4 CO2 Calculations'!I97	='Step 1-4 CO2 Calculations'!J97	='Step 1-4 CO2 Calculations'!K97	='Step 1-4 CO2 Calculations'!L97	='Step 1-4 CO2 Calculations'!M97	kg CO2/boe (gas supplied)
14	Sum effekter i gass marked og kraftmarked	=SUM(J10:J13)	=SUM(K10:K13)	=SUM(L10:L13)	=SUM(M10:M13)	=SUM(N10:N13)	kg CO2/boe (gas supplied)
15							
16							
17							
18							
19	**Global CO2 Emissions (kg CO2/year)**	**2030**	**=J19+5**	**=K19+5**	**=L19+5**	**=M19+5**	
20							
21	Electrification						
22	CO2 emissions reduced due to electrification -National CO2 reduction	=-'Step 1-4 CO2 Calculations'!$H$6+'Input - CO2 & fuel gas calc'!$G$59	=-'Step 1-4 CO2 Calculations'!$H$6+'Inpu	=-'Step 1-4 CO2 Calculations'!$H$6	=-'Step 1-4 CO2 Calculations'!$H$6+'Inj	=-'Step 1-4 CO2 Calculations'!$H$6+'I	kg CO2/yr
23							
24	Calcualted Global netto CO2 Emission						
25	Step 1 - Increased EU consumption due to market effect	='Step 1-4 CO2 Calculations'!$H$17	='Step 1-4 CO2 Calculations'!$H$17	='Step 1-4 CO2 Calculations'!$H$1	='Step 1-4 CO2 Calculations'!$H$17	='Step 1-4 CO2 Calculations'!$H$17	kg CO2/yr
26	Step 2 - Demand substitution due to increased gas from Step 1	='Step 1-4 CO2 Calculations'!I49	='Step 1-4 CO2 Calculations'!J49	='Step 1-4 CO2 Calculations'!K49	='Step 1-4 CO2 Calculations'!L49	='Step 1-4 CO2 Calculations'!M49	kg CO2/yr
27	Step 3 - Production (offer) substitution due to increased gas from Step 1	='Step 1-4 CO2 Calculations'!$H$73	='Step 1-4 CO2 Calculations'!$H$73	='Step 1-4 CO2 Calculations'!$H$7	='Step 1-4 CO2 Calculations'!$H$73	='Step 1-4 CO2 Calculations'!$H$73	kg CO2/yr
28	Step 4 Thema - increased emissions from increased power production for platform electrification	='Step 1-4 CO2 Calculations'!I98	='Step 1-4 CO2 Calculations'!J98	='Step 1-4 CO2 Calculations'!K98	='Step 1-4 CO2 Calculations'!L98	='Step 1-4 CO2 Calculations'!M98	kg CO2/yr
29	Total effects in the gas market and power market	=SUM(J25:J28)	=SUM(K25:K28)	=SUM(L25:L28)	=SUM(M25:M28)	=SUM(N25:N28)	kg CO2/yr
30							
31	Global netto CO2 emissions due to electrification, gas market effects and power market effects	=J29+J22	=K29+K22	=L29+L22	=M29+M22	=N29+N22	kg CO2/yr
32	Global netto emissions due to electrification, gas market effects and power market effects vs national	**=J31/J22**	**=K31/K22**	**=L31/L22**	**=M31/M22**	**=N31/N22**	

Universitetet
i Stavanger