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Carbon footprint assessment of the Vega subsea field – a preliminary study for the environmental footprint

by

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ABSTRACT

Subsea tie-in fields on the Norwegian continental shelf (NCS) appear to have extremely low greenhouse gas intensity based on available environmental data, as emissions related to offshore oil and gas processing is reported from the host platform. The goal of this thesis was to quantify the environmental footprint of the subsea field Vega with respect of emission to air. The work was simplified by using carbon footprint as a single-issue method. A carbon footprint should, according to ISO 14067, be quantified by greenhouse gas (GHG) emissions and removals over the life cycle of a product. The methodological framework described by the international organization for standardization was adapted to this study by applying a bottom-up approach for data collection and inventory modelling. A case study was included to illustrate an example of how the inventory model can be used. **Results:** The carbon footprint (total GHG emissions) and GHG intensity of Vega were estimated as 0,290 million tons CO_2-eq. and 0,411 kg CO_2-eq./GJ respectively for 2010-2017. Discussion around the inventory results is focused on GHG intensity rather than total GHG emission (i.e. carbon footprint). This was to reflect the Norwegian Environmental Agency's goal to both reduce greenhouse gas emission and increase production of hydrocarbons on the Norwegian continental shelf. **Conclusion:** Applying a life cycle inventory approach drastically changed the emission profile of Vega, compared to the current reporting practice. However, as this project represent the very early stage of implementing life cycle thinking in Wintershall, the principles of the life cycle inventory are more important than the inventory results itself. Further implementation of life cycle assessment within Wintershall should be based on the intended use and goals set by the company.

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Table of Contents

List of Tables

List of Figures

LIST OF ABBREVIATIONS

GHG	Greenhouse gas
GWP	Global warming potential
IR	Infrared
RF	Radiative forcing
IRF	Impulse response function
EIO	Environmental input-output analysis
PA	Process analysis
SETAC	Society of environmental toxicology and chemistry
ISO	International organization of standardization
NCS	Norwegian continental shelf
NOROG	Union of Norwegian oil and gas production (NOR; Norsk olje og gass)
NEA	Norwegian environmental agency (NOR; Miljødirektoratet)
NPD	Norwegian Petroleum Directorate
NGER	National Greenhouse Account Factors
UNFCCC	United Nations Framework Convention on Climate Change
IPCC	International Panel on Climate Change
COP	Conference of the Parties
EF_{FS}	Field or equipment specific emission factor
EF_{NOROG}	Emission factor given by NOROG
EF_{NGER}	Emission factor given by NGER
Ak_1	Allocation key 1 (total allocation)
Ak_2	Allocation key 2 (gas allocation)
Ak_3	Allocation key 3 (oil/condensate allocation)
Ak_4	Allocation key 4 (produced water allocation)
o.e.	Oil equivalents
MJ	Mega joule
GJ	Giga joule
Sm^3	Standard cubic meter
CO_2	carbon dioxide
CH_4	Methane
nmVOC	Non-methane volatile organic compounds
NO_x	Nitrogen oxides
SO_x	Sulphur oxides
N_2O	Nitrous oxide
CO	Carbon monoxide
HFCs	Hydrofluorocarbons

PFCs	Perfluorocarbons
SF_6	Sulphur hexafluoride
CO_2-eq.	Carbon dioxide equivalent
LCI	Life cycle inventory
LCA	Life cycle assessment
LCSA	Life cycle sustainability assessment.
LWI	Light well intervention
RLWI	Riserless light well intervention
IMR	Inspection, maintenance and repair
WHRU	Waste heat recovery unit

1. BACKGROUND AND PURPOSE OF THIS STUDY

This thesis was initiated by Wintershall with the aim of increasing the understanding of environmental impacts resulting from the Vega subsea field. The following objectives were defined by Wintershall;

- Define boundaries for environmental footprint extension (i.e. phases/activities to include).
- Data collection of environmental data Vega and Gjøa.
- Establish calculation model for host emission.
- Presentation of total environmental footprint in end report.

As two students joined this project, the workload was early divided into discharge to sea and emission to air. This thesis focuses on emission to air, i.e. gaseous substances that are released to the atmosphere. Under the absence of a clear definition of environmental footprint, the scope was reduced to include only carbon footprint.

The current environmental reporting practice in Norway allocates most emissions from subsea productions to the host platform. Emission across the Norwegian continental shelf (NCS) is therefore reported on facility level. The only emissions reported from subsea are related to mobile units, e.g. marine vessels or rigs, that are used for taking over well control to perform tests, workovers or interventions. Emissions that are indirectly linked with oil and gas production, e.g. marine activity and waste handling is reported under other regimes than petroleum activity. One can argue that this reporting practice is misleading when quantifying the emission that occur due Vega production, because most emissions are allocated to the host platform, Gjøa. Historical emissions of greenhouse gas (GHG) and production data for Vega and Gjøa are shown in fig. 1 and fig. 2 respectively. By simply looking at these diagrams, Vega production seems to be much more GHG efficient than

Gjøa. However, we know this is not the actual case since emissions from the Gjøa platform is related to both Vega and Gjøa production. The actual contribution from Vega is therefore the main knowledge gap that will be investigated in this thesis.

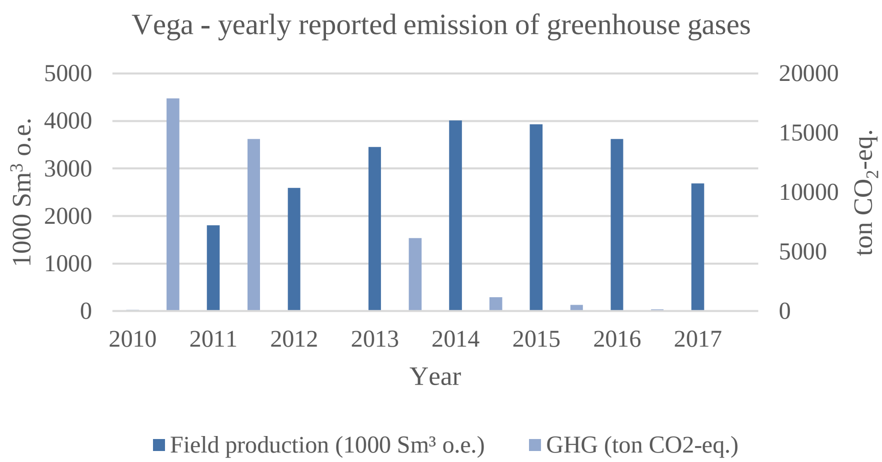

Figure 1 Vega production reported as 1000 standard cubic meter (Sm^3) oil equivalence (o.e.) and greenhouse gas emission, reported as ton CO_2 equivalence (CO_2-eq.). Data is retrieved from Environment Hub database.

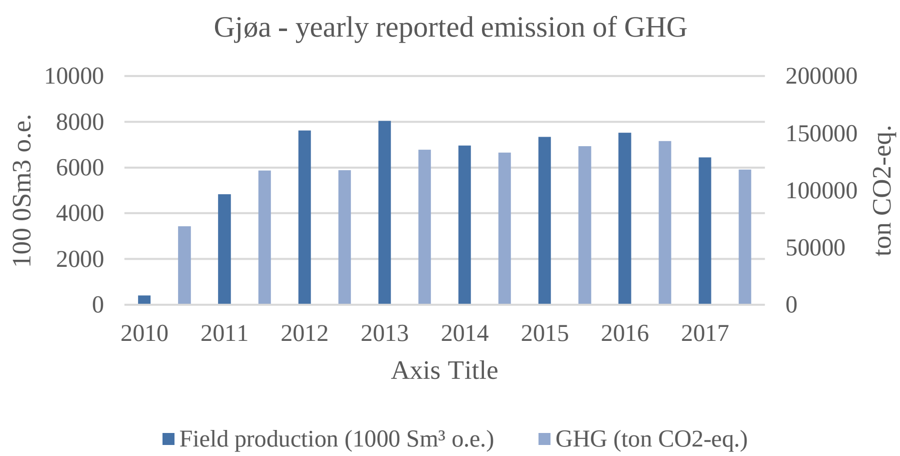

Figure 2 Gjøa production reported as 1000 standard cubic meter (Sm^3) oil equivalence (o.e.) and greenhouse gas emission, reported as ton CO_2 equivalence (CO_2-eq.). Data is retrieved from Environment Hub database.

One can also argue that this is a trivial issue, as the emissions will be the same independent of how they are reported or allocated. However, it is crucial that the operators have complete overview of environmental impacts across their entire supply chain, to make more informed decisions and set realistic reduction targets. For this, knowledge about how emission emerge, e.g. emission sources, is particularly of interest. Moreover, subsea production is increasingly relevant across the Norwegian continental shelf, as new discoveries have the tendency to be on the smaller scale. Discovery are also more commonly located in deeper water and more remote places, where fixed installations won't be feasible [1].

2. INTRODUCTION

The aim of this chapter is to include all aspects that were important for quantifying the carbon footprint of Vega. First, climate change theory is described to give an understanding of global warming. Life cycle assessment (LCA) as described by the international organization of standardization (ISO) was the chosen methodological framework and will be described in the following sections. Environmental aspect specific to oil and gas activity across the NCS is then explained, by Norwegian environmental regulations and common emission sources. Lastly, a system description of the Vega subsea field is presented.

2.1. Climate change theory

This study focuses on global warming, as this is the biggest concern regarding emission to air from the oil and gas industry. Climate change theory is important to understand the terms used in this thesis. The Intergovernmental Panel on Climate Change (IPCC) is the leading international body for climate change assessment, and hence the preferred source of theory. It was established by the United Nations (UN) in 1988 with the goal of providing a clear scientific understanding of climate change [2]. IPCC concluded with a 95% confidence interval that emission from human activity is the biggest contributor to climate change in the fifth assessment rapport (AR5), which was published in 2013 and 2014 [3]. It should be noted however, that IPCC also have received critique for lacking ability to cover new discoveries due to the rapid expansion of the climate change literature [4].

2.1.1 GREENHOUSE GASES AND GLOBAL WARMING POTENTIAL

A GHG is defined by the IPCC as 'gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of infrared (IR) radiation emitted by the Earth's surface, the atmosphere and clouds [5]. GHG intensity will for oil production be defined as GHG emission per unit of hydrocarbon produced. All molecules with three or more atoms have a change in dipole moment and will absorb IR radiation. However, radiation from the Earth is mainly in the thermal IR region between 4 and 30 µm, and a GHG must therefore be IR active within this region. The dry atmosphere is mainly composed of N_2 and O_2 – non-IR absorbers [6].

Molecular vibrations, rotation and motion, caused by the IR absorption, increase the average thermal energy of the molecule. This energy can be redistributed among atmospheric molecules several times by emission and absorption. It will eventually escape the atmosphere – either back to the earth's surface or to space. The difference in energy absorbed by the earth and emitted to space is controlling global warming change. The net change energy balance per area unit is known as radiative forcing. Positive or negative value of radiative forcing of a given gas decide if it has a warming or cooling effect respectively. The more energy absorbed and the longer atmospheric life-span of a GHG, the more will it contribute to global warming. However, the dependence on the wavelength of absorption is complicated, because atmospheric gases have overlapping IR-absorbing properties [7].

Long-lived GHGs have a global temperature effect, as the climate change effect is assumed to be independent from the point of release on the earth. This is because a long life-span allows GHGs to mix well throughout the atmosphere at a faster rate than they are removed. Their global concentration can therefore be measured from a few locations quite accurately [8].

Global warming potential (GWP) is frequently used as a simplified estimation of future climate impacts from GHG emissions based upon radiative properties of GHGs. It is a measure of the relative radiation efficiency, i.e. how much IR-radiation absorbed by a given atmospheric gas compared to CO_2 over a given time horizon (TH) [7]. IPCC commonly applies a 100-year TH when calculating GWPs. Global warming potential as an absolute value (AGWP) for a gas (x) can be expressed as [9];

$$AGWP_x(TH) = \int_0^{TH} RF_x(t)dt = \int_0^{TH} A_x IRF_x(t)dt$$

Where $RF_x(t)$ is the radiation forcing at time *t* caused by the emission that was released at time *t=0*. This equation treats emissions as pulses, i.e. that emissions are released simultaneously at a given time. The pulse can be large or small, depending on the amount of emissions. It has been argued that the using correct timing of GHG is crucial and that time-adjusted global warming potentials (TAGWP) should be used [10]. RF can also be expressed as the product of its radiative efficiency (A_x) and the impulse response function, IRF. IRF_x represent the time-dependent abundance of gas (x) due to the added emission pulse. Since GWPs are intended for studying relative impacts rather than absolute impacts of emissions, it can finally be defined as [9]:

$$GWP_x(TH) = \frac{AGWP_x(TH)}{AGWP_{CO2}(TH)}$$

Where the GWP of a gas (x), over a given TH is expressed as figure relative to the GWP of CO_2. GWP depends strongly on the behavior of the reference gas and is sensitive to the choice of TH [8]. GWP values given by the IPCC are generally accepted, and are shown in tab. 1.

Table 1 Global warming potentials with a 100-year time horizon given by the international panel on climate change in the fifth assessment report (AR5) [3].

Compound	**Chemical formula**	**Lifetime**	**Rad. eff. ($Wm^{-2}ppb^{-1}$)[2]**	**GWP (100) (AR5)**
Carbon Dioxide	CO_2	See notes[1]	$1,4*10^{-5}$	1
Methane	CH_4	12	$3,7*10^{-4}$	28
Nitrous oxide	N_2O	114	$3,03*10^{-3}$	265

[1] CO_2 response function used by IPCC is based on Bern Carbon cycle model (Bern2.5CC) [7]
[2] GWP for methane includes indirect effects from enhancements of ozone and stratospheric water vapor

Due to our limited knowledge of uptake, distribution and removal processes, the atmospheric response time of CO_2 is subjected to significant scientific uncertainties. Hence, numerical GWP values can change considerably as research improves our knowledge of these natural processes [9].

Further discussion about how these values are derived is outside the scope of these thesis. However, the main parameters for GWP calculations were illustrated nicely by Hodnebrog *et al.*, which is shown in the fig. 3 [11].

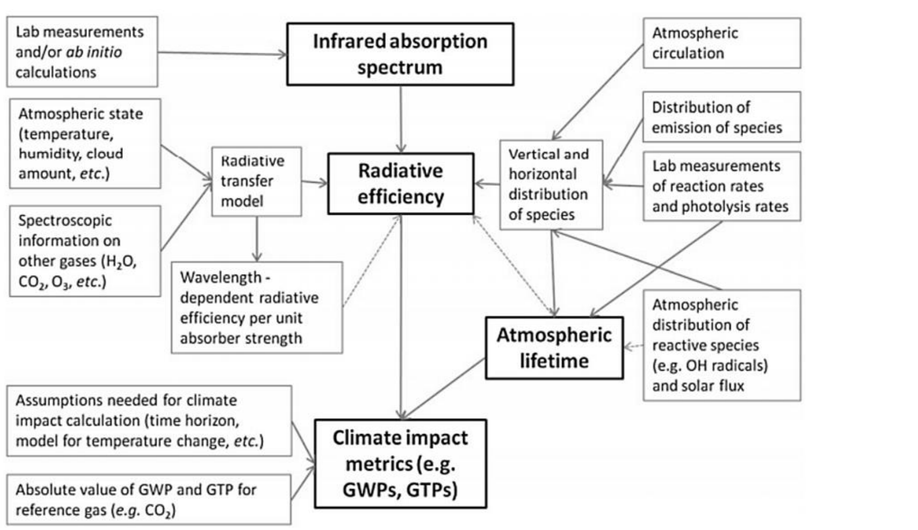

Figure 3 Schematic illustration of parameters required for calculations of climate impact metrics, from Hodnebrog *et al*. [11].

2.1.2. DEFINITION OF CARBON FOOTPRINT

Within environmental assessment research there have been a communication driven trend towards simplification. Consequently, the term carbon footprint is frequently used for expressing concerns about global warming to the general public [12]. The term itself originates from ecological footprint. Ecological footprint was introduced in the literature by Wackernagel and Rees in 1996 [13]. Ecological footprint aims to describe the total area of land, measured in global hectare, needed to produce some level of human consumption. In a similar way that ecological footprint is linked to land area consumption, carbon footprint aims to link GHG emission to the contribution of global climate change. To evaluate the usage of land, one must follow human consumption back to the extraction of natural resource. This makes life cycle thinking essential in ecological footprint assessment. Regarding carbon footprints, however, companies and organizations have shown the tendency to measure their GHG emission only from direct emissions and emission from purchased power. This excludes large parts of the emissions and give incomplete information about true sources of emission [14]. The main argument to include all life stages is to allow the largest, most cost-efficient, sources of carbon emissions along the supply chain to be targeted first [15].

There has been a lack of consensus of what to include in a carbon footprint, both with respect of boundaries, substances and impact. Under the absence of a clear, scientific definition, governments, businesses and consultancies (sometimes referred to as the "grey literature"), have provided their own definitions and procedures [14]. Standards have been developed to overcome this challenge. The ISO published their version in 2013, which is known as ISO14067 – Carbon footprint of products – Requirements and guidelines for quantification and communication [16]. ISO defines carbon footprint of products as 'sum of GHG emissions and removals in a product system, expressed as CO_2 equivalents and based on a life cycle assessment' [16]. ISO is one of the most important organizations for standards, and ISO14067 is therefore one of the most influential standard for assessing carbon footprint. The method described in this standard is closely related to LCA, which will be discussed more in detail in chapter 2.2.

Carbon footprints can be calculated either based on Process Analysis (PA) or Environmental Input-Output (EIO) analysis [14]. EIO analysis is a top-down approach, which use economic accounts together with environmental data to establish carbon footprints. Such analyses can assess whole economic system, therefore allowing comprehensive overview of the life cycle. It is also time efficient. However, this comes at the expense of details since assumptions such as prices, fuel consumption and emission factors are usually made on sectors levels. PA is a bottom-up approach, meaning that relevant data is collected and added to create the life-cycle of the object being analyzed. It is used for understanding environmental aspects of individual products, processes or services [14]. Both primary and secondary data can be used for calculating emissions. Primary is measured data collected from actual processes or factories. Secondary data is collected from the literature, statistics or databases. There is generally more uncertainty related to secondary data, and one should therefore aim to use primary data whenever possible [12].

There exist other types of footprint as well, for example water footprint and nitrogen footprint. They are all single-issue methods, meaning that they investigate only one aspect of complex environmental systems. Footprinting can therefore be regarded as a simplified way of assessing environmental impacts. Interestingly, other environmental assessment methods are becoming increasingly sophisticated, e.g. life cycle costing (LCC), life cycle sustainability assessment (LCSA) and eco-efficiency assessment [12]. These methods include comprehensive sets of impact categories and new dimensions of sustainability. These two trends, simplification and sophistication, appears to be contradictories. However, researchers have found that they work complementary to each other, since organization unexperienced with sustainability reporting typically use simplified assessments, such as carbon footprint, as an entry level before implementing more comprehensive assessment methods. An adapted version of Maslow's pyramid of need can be used to illustrate this (fig. 4) [12].

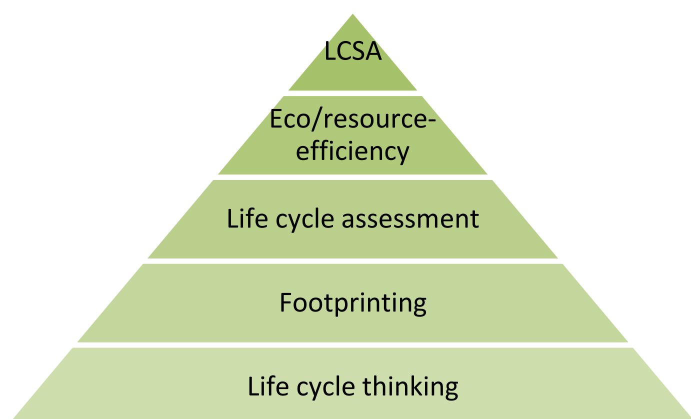

Figure 4 Maslows pyramid of needs adapted for environmental assessment, from Finkbeiner et al. [12], LCSA = life cycle sustainability assessment.

The adapted pyramid follows the same hierarchical relationship as Maslow's pyramids of need. The original pyramid shows basic phycological need like water and food at the bottom, followed by belonging, love and safety before self-actualization is placed at the top. In the adapted version, life-cycle thinking represent the basic requirements and the methods get increasingly comprehensive towards the top [12]. The methods listed as examples in the adapted pyramid is naturally subjected to change as research improves. However, the principle will nevertheless be to address the different levels of sophistication with the aim of defining developing paths that are suitable for a given organization or project.

2.2. Life cycle assessment

LCA is a methodological framework for quantifying and analyzing environmental impacts related to the life cycle (i.e. from extraction of raw materials to final disposal) of products, services or processes. The life-cycle is also known as “cradle to grave”, or when only part of the life-cycle is included, “cradle to gate” or “gate to gate” (fig. 5).

Figure 5 Cradle to gate life cycle of oil and gas production.

For the matter of this thesis, LCA was chosen as methodology to recognize both direct and indirect emission of subsea producing fields.

2.2.1. BRIEF HISTORY

LCA originates from the early 1970s, when techniques such as “net energy analysis”, quantified material and energy use of a product or process. Some later studies also included emissions and wastes [17]. The Society of Environmental Toxicology and Chemistry (SETAC) was one of the first organization that recognized the need for a standardized way to assess the complex environmental impacts from human activities. As a result, the SETAC North American LCA Group was formed [17]. The ISO started similar work soon afterwards. ISO standardization process of LCA was initiated in 1993, and a general framework, called the ISO 14040 series, was published in 1997 [18]. The SETAC LCA group was broadly involved in the preparation of this standard. The ISO standard has grown the be the most recognized methodology within LCA. After the last updated in 2006, it is currently known as ISO 14040 [18] and ISO 14044 [19]. ISO have in more recent times published several standards which are based on the original LCA standard [20].

2.2.2 ISO METHODOLOGICAL FRAMEWORK

The ISO methodological framework asses the life cycle of a product by its product system. The product system is characterized by its function(s) rather than the product and/or service it produces. Linking environmental impacts with the function instead for the product or service itself, provide a more reliable basis for comparison. This is because different products or services may show different performance characteristics and can therefore not be directly compared. An essential feature of LCA is therefore the use of functional units. A functional unit is a quantified performance of the product or service in the product system. The main purpose of functional units is to estimate the overall environmental performance per unit of delivered service [18].

The product system can be divided into several process units that are connected by intermediate flows of products and or waste (fig. 6). Each process unit may also have their own flow of inputs and outputs. There can be several unit processes within a product system and different product system may also be interlinked by intermediate flows [18].

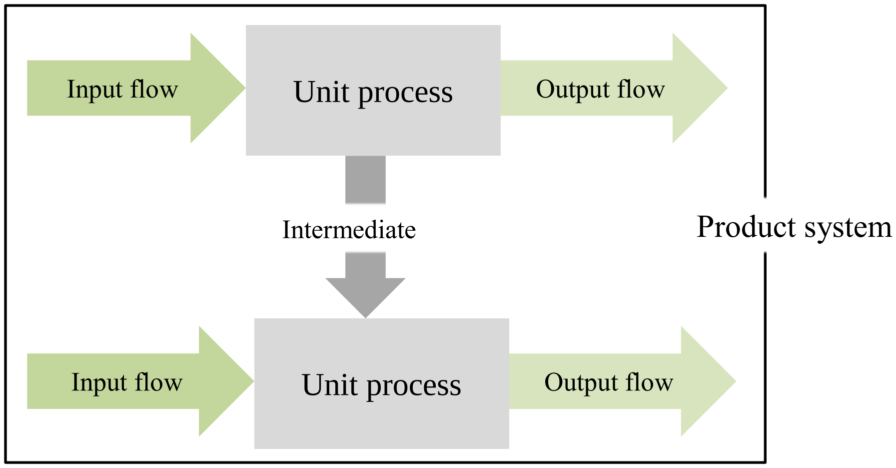

Figure 6 Illustration of compartments and flows within a product system. Adapted from ISO 14040 [18].

It is fundamental that every LCA study is understood in accordance with the stated goal and scope. To ensure this, ISO LCA include interpretation as one of four phases of LCA working model. This is illustrated in the fig. 7.

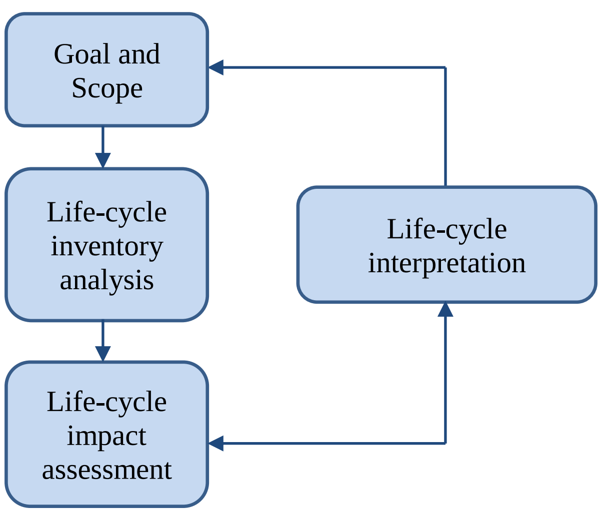

Figure 7 Illustration of the main stages of a life cycle assessment. Adapted from ISO 14040 [18].

As seen from the fig. 7, the working model illustrate a loop. This is due to the iterative nature of LCA, meaning that requirements or limitations may be discovered along the way. Hence, the scope may need modification during the study to meet the original goal, or approximations must be made [18]. The four steps of an LCA study are briefly described in the following sections.

Goal and Scope

The goal describes the reason for carrying out the study and the intended audience. The scope explains the extent of the study by defining the product system, the functional unit, the system boundary, allocation procedures, impact categories and assessment methods, data requirements, assumptions and limitations [18].

Life cycle inventory

Environmental burdens are quantified and allocated to their relevant functional units by data collection and calculations in the life cycle inventory (LCI) analysis. Depending on the system being analyzed, relevant data consist of energy inputs, raw material inputs, waste, emissions to air, discharges to water and soil, products, co-products and other environmental aspects. Allocation should be partitioned between the different functions of a product system in such a way that reflects the physical relationships between them [18].

Life cycle impact assessment

Life cycle impact assessment (LCIA) assigns the result found in LCI to different impact categories. Impact categories for emission to air can for example be GWP, acidification potential and eutrophication. Collectively, these calculations make up the LCIA profile which provide information about environmental issues related to input and output flows of the product system [18].

Interpretation

The life cycle interpretation is intended to assure that the LCA results and conclusions are in accordance with the goal and scope. The interpretation work model is shown in fig. 8. The interpretation shall also consider whether the definitions and assumptions used in the LCA are appropriate and assess limitations and uncertainties. Different evaluation techniques can be included in the interpretation, e.g. completeness check, sensitivity check, consistency check and other checks [19].

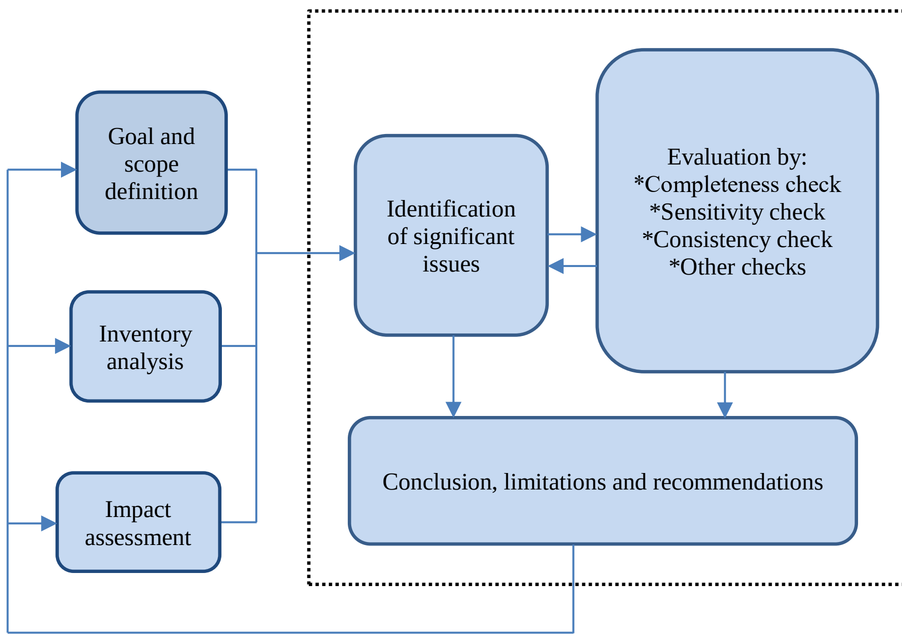

Figure 8 Interpretation work model. Adapted from ISO 14044 [19]

The completeness check is a process of verifying if the data included in the LCA is sufficient for reaching conclusions according to the goal and scope. It attempts to identify data gaps and evaluate requirements to complete data sets.

2.2.3. APPLICATIONS OF LIFE CYCLE ASSESSMENT

Over the three last decades, LCA has been identified as a useful tool for environmental assessment, with countless applications. By observing the whole life cycle of an activity along its supply chain, LCA can identify stages with the highest impact, and again locate the biggest potentials for improvements. What is more, using LCA can avoid shifting of environmental burdens, which refers to transferring negative impacts from one part of the life cycle to another. In this way, LCA contributes to a more holistic understanding of environmental impacts [12].

LCA can be applied to both macro-scale sectors, such as the public sector, and micro-scale areas, e.g. individual organization, products, services and processes. As a result, there is generally a need for high flexibility in the methodology. This is reflected in the ISO LCA standard, which allows for differences regarding methodological approaches. One can therefore say, "there are no single method of conducting LCA". However, this rise conflict with governmental intentions of implementing life cycle thinking in environmental policy, where transparent and harmonized methods are sought of [21]. As a response, different public and commercial actors have developed more detailed and comprehensive LCA guidelines [22] [23] [24]. For example, the European Commission published Environmental Footprint guides (a modified LCA method) for products and organizations in 2012, as a part of the ongoing "Single Market for Green Products" initiative [25]. Despite the intention of improving EU environmental policy, concerns about the reliability of the method have been raised [26]. If LCA can be standardized as a common set of detailed procedures, and at the same time maintain flexible enough to cover most LCA cases, is not yet fully understood.

Life cycle assessment for industrial processes

LCA has mainly been applied to products, but the literature shows increasing interest for its potential within industrial processes [27] [28]. Applying LCA for industrial process does not necessarily require changes in the methodology, but rather in detail level. LCA has commonly regarded processes as “black boxes” and assume fixed operation conditions. In this way, only input and outputs are taken into consideration, excluding parameters like operation conditions and process design. In these black boxes, there will be a potential to improve the environmental performance. It is this potential that can be exploited by integrating LCA as an environmental tool in process engineering [27].

2.2.4. Bottom-up approach of implementing life cycle assessment

The ISO methodological framework is complex and have a generic focus on up-stream decision making. A bottom-up LCA approach was developed by Mitchell and Hyde in 1999, to meet industry needs of implementing LCA as an environmental tool [29]. The bottom-up approach is based on the assumptions that LCA can be used to locate industrial small-scale positive changes. Here, process units are separated into single components. Operational and production processes can then be assessed. To utilize LCA in the industry it is argued that individual models must be developed to meet requirements specific for a given organization [29]. Tab. 2 gives an overview of what differentiate the bottom-up approach from a typical ISO LCA.

Table 2 Characteristics of the bottom-up approach to life cycle assessment, compared with the typical life cycle assessment, from Mitchell and Hyde [29].

Characteristics	**Bottom-up approach**	**Typical LCA (ISO1400 series)**
Scale (System boundary)	Single operation (unit process) boundary	Large inclusive system boundary usually incorporating several unit processes
Scope (LCA process)	LCA ongoing, educative process within organization	LCA carried out by professional body outside of organization and report remains valid until operation change
Scale of technology	Appropriate technology	High technology
Scale of data collection	Data collection within and by company	Data collection from data base, average data or company
Involvement	Organization involved in process and introduction to LCA	Only management is generally involved
Analysis detail	Analyses each component of unit process	Smallest analysis is generally unit processes
Concern	Concerned with own responsibility	Concern up-stream
Education	Education of all involved in organization is an ongoing process	Little education of company employees

2.3. Environmental regulation for oil and gas production on the Norwegian continental shelf

The aim of this chapter is to explain how operators on the NCS must relate to environmental policies. The Norwegian oil and gas association (NOROG) provides guidelines to ensure common practice among all operators [30]. Environmental Hub (EEH) is used as reporting system between the operators and the Norwegian environmental agency (NEA). As pollutants are different by nature, environmental laws and regulations therefore tend to be media-limited [31]. For the NCS it can be divided into discharge to sea and emission to air. Only regulation related to emission to air is described here.

Regulations differ for the petroleum sector and marine sector. The laws for petroleum activity step into action whenever an operating unit (e.g. rig or vessel) takes over well-control. Taking over well-control means that operations are performed inside the well. However, several lighter subsea well operations are done around or outside the well, e.g. without taking over well-control.

2.3.1. EMISSION TO AIR

According to the NEA, the main emission from petroleum activity across the NCS includes the GHGs; carbon dioxide (CO_2) and methane (CH_4) and the non-GHGs; non-methane volatile organic compounds (nmVOC), nitrogen oxides (NO_x) and sulphur oxides (SO_x) [32]. Relative emission amounts are illustrated in fig. 9. Even though nitrous oxide (N_2O) is known to have high GWP, emission of this compound is regarded as very small and therefore not reported [32]. Emissions of NO_x and nmVOC are precursors to ozone due to photochemical process [33]. The climate change of ozone is more complex and difficult to model than long-lived GHGs, which are globally well-mixed. This is because the radiation role of ozone is dependent of the altitude where the concertation change happens and is also spatially distributed. Ozone is also short-lived specie with a residence time varying from weeks to months. NO_x emission play an important role in the earth's nitrogen cycle [33].

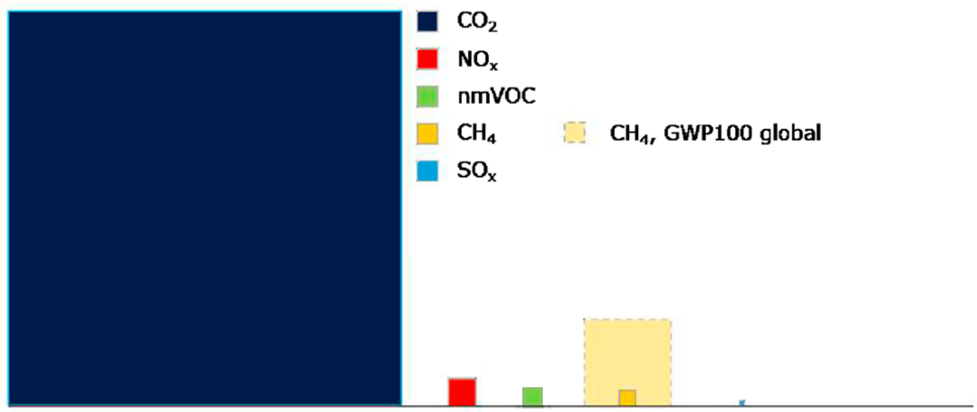

Figure 9 Illustration of the relative amounts of compounds emitted from the oil and gas industry across the Norwegian conctinental shielf. GWP100 = global warming potential with a time horizon of 100 years. The figure is modified from the Norwegian Environmental Agency [32].

In 2012 it was reported that the petroleum industry accounted for approximately ¼ of all greenhouse gas emissions in Norway. The operational phase is by far (>90%) the biggest source of climate gas emissions, based on studies published by the NEA [32].

Regulations for emission to air are mainly set to fulfill international commitments, which is primarily concerning global warming The NEA have alsp goal to both reduce greenhouse gas emission and increase production of hydrocarbons on the Norwegian continental shelf, i.e. lower the GHG intensity. The leading actor for international climate change strategies is United Nations Framework Convention on Climate Change (UNFCC). In addition to this, Norway has a national CO_2 fee which was introduced in 1991 [34].

United nations framework convention on climate change

UNFCCC is an international treaty that was established in 1992 by UN in Rio de Janeiro. Its main objective is to 'stabilize the GHG concentration in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system' [35]. After the convention came into force in 1994, there has been held yearly meetings known as 'Conference of the Parties' (COP). The objective of COP is to evaluate the progress and negotiate binding agreements to the treaty, with the most important so far being the Kyoto protocol in 1997, and the Paris agreement in 2015. IPCC is the scientific body of UNFCCC. Its main objective is to provide a scientific basis of climate change, its impacts and future risks, and options for adaptation and mitigation [36].

UNFCCC builds on 'common but differentiated commitments', meaning that developed and industrialized countries should take more responsibility than less developed countries. For this purpose, UNFCCC has established a classification system [37]:

- Annex I: industrialized (developed) countries and economies in transition (EIT).
- Annex II: industrialized countries and members of the Organization for Economic Cooperation and Development (OECD). These countries are required to provide financial and technical support to Non-Annex I or EIT countries, to assist them in reducing GHG emissions.
- Non-Annex I: developing countries, countries that are particular vulnerable to climate change (low-lying coastal areas, drought, desertification), or have high potential economic impacts (e.g. countries that have its main income from fossil fuels). Non-annex countries are imposed less responsibility for GHG reductions and is subjected to financial and/or technological support from Annex II.

Kyoto protocol

The Kyoto Protocol was adopted in Kyoto, Japan, in December 1997 by the UNFCCC and went into force in February 2005 [38]. It is a legally binding agreement that sets quantified and timed commitments to GHG emission reduction targets. GHG included are CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6) [39].

For the first period (2008-2012), Annex II states were supposed to reduce GHGs corresponding to 1990 levels emissions. Norway is Annex II country but was allowed to increase emissions by 1 % due to its special position in the oil and gas industry. The mechanisms for such reductions are international emission trading (carbon market), clean development (environmental investment) and joint implementation (transfer emission reduction units from other countries). For the second period (2013-2020), 29 countries plus the EU are committed to a 20% reduction target compared to 1990 [40].

The main principle of the carbon trading market, as a central part of the Kyoto Protocol, is that companies receive less carbon shares than their expected emission require. They will therefore have to reduce their emission or buy more carbon shares from the free carbon market [38]. Norway is connected to this carbon market through the EU emission trading scheme. The NEA has the main administrative responsibility through the Greenhouse Gas Emission Trading Act [41]. Roughly half of Norwegian industry is covered by this act, including petroleum industry, air transportation and land-based industry [42].

Paris agreement

The Paris agreement is a legally binding global climate deal was adapted at the climate conference in 2015. 195 countries agreed to a long-term goal of keeping the global average temperature increase less than 2 °C above pre-industrial levels. It is currently believed that risks and impacts of climate change is significantly lower and manageable within this limit [43].

2.4. Emission sources from offshore oil and gas production

This chapter aims to provide understanding of how emissions emerge from offshore oil and gas production. The processing philosophy vary from field to field, depending on both economical, technical and environmental factors. Emission sources will therefore be field specific. However, sources are generally divided into combustion sources (e.g. engine, flaring, boilers), operational emission (cold venting and fugitives), loading oil and indirect sources [30]. Sources are described with their relevant emission compounds in tab. 3.

Table 3 Emission sources related to offshore petroleum processing with their respective compounds and nature of emission, as described by the Norwegian oil and gas association [30]. nmVOC = non-methan volatile organic compounds.

Emission Source	Compound	Nature of emission
Combustion	CO_2	Oxidation of carbon during the combustion process
	N_2O	Formed from nitrogen bound in the fuel
	CH_4	Incomplete fuel combustion
	NO_x	Oxidation of nitrogen bound in the fuel or nitrogen[1]
	SO_x	Combustion of sulphur present in the fuel
	nmVOC	Incomplete fuel combustion[2]
Cold venting (operational emission)	CH_4 nmVOC	Operational emissions purposely routed to the atmosphere
Fugitive sources (operational emission)	CH_4 nmVOC	Unintentional release from equipment leaks or piping components[2]
Loading oil	CH_4 nmVOC	Vapor emitted from shuttle tanker when loading oil from offshore installations
Indirect sources	Activity specific	Emission that are a consequence of activities of the reporting company, but which source is controlled or owned by another party

[1]There is lacking scientific evidence that suggest N_2O are formed directly by thermal reactions from atmospheric nitrogen [44]

[2] [45]

2.4.1. COMBUSTION

Several gaseous products can be formed from the combustion of fossil fuel, e.g. CO_2, carbon dioxide (CO), sulfur (SO_2), NO_x, N_2O, VOCs or hydrocarbons. This is closely linked with the elements in the fossil fuel and the combustion process [46]. Gas turbines located offshore are known to be the main source of GHG emissions from oil and gas production on the NCS. Other combustion sources are flaring, engines and boilers [32].

Combustion theory of CO_2

Theoretically, stoichiometric combustion of hydrocarbons is explained by the chemical equation [47];

$$C_xH_y + zO_2 \rightarrow xCO_2 + \frac{y}{2}H_2O, \qquad \text{where } z = x + \frac{y}{4}$$

CO_2 emission from combustion sources are based on complete conversion of fuel carbon to CO_2. Hence, CO_2 emission can be estimated based on the weight of carbon in the fuel (found in analysis such as gas chromatography) and the fuel consumed [47].

Combustion is an energy yielding process, because the products (CO_2 and water) have a lower enthalpy than the reactants. The amount of heat released when a fuel is combustion is described by its calorific value (also called heating value). The calorific value is defined as the heat released during complete combustion of a unit (mass or volume). It is an important unit for characterizing the potential energy stored in a hydrocarbon fluid. The calorific value is calculated wither as gross calorific value (GCV) or net calorific value (NCV). GVC assumes that all vapor produced during the combustion is fully condensed, whereas NCV assumes that the water leaves as vapor [48].

2.4.2. COLD VENTING AND FUGITIVE SOURCES

CH_4 and nmVOC are volatile compounds and can therefore escape from the process to the atmosphere in a direct manner. This is frequently called emission of waste gas and occur either from cold venting or fugitive sources. The main difference is that cold venting occurs from dedicated emission points, whereas fugitive emissions are gas leaks that unintentionally can happen anywhere in the process. Dedicated emission points can be local vents from individual components, a common vent for the whole facility or a flare when not burning [45].

The original methodology for quantifying emissions from cold venting and fugitive sources was established in the mid-1990s by Aker Engineering [45]. Emissions based on this methodology were calculated by generic source emission factors and activity factors. The activity factor is the amount of gas processed in the facility. This methodology was used until 2017. The shift in methodology was based on a project initiated by the NEA 2014. Here, CH_4 and nmVOC emissions from cold venting and fugitive sources on the NCS were mapped. Hydrocarbon systems from 15 facilities were thoroughly investigated. The remaining 53 facilities were reviewed by questionnaire. Final reports were published in 2016 [49]. This project revealed 48 potential emission sources, of which a full overview can be found in Appendix 2. Only 13 emission sources have been included in the previous methodology. The increased amount of emission sources is partly because original sources were broken down to sub-sources, however several new sources were also discovered [45].

It was discovered huge variations of waste gas amounts released from the individual processes, and across the different facilities. The insignificant sources were estimated to contribute with approximately 3% of all emissions [45].

The survey also proposed a new emission quantification methodology and evaluation of emission reduction potentials. Published environmental data reported is as of 2017 based on the new methodologies. A full overview of these methodologies can be found in Appendix 2.

2.4.3. Indirect sources

Indirect sources are emissions that are a consequence of activities of the reporting company, but which source is controlled or owned by another party. Relevant sources for subsea oil and gas production are marine activities dedicated for subsea operations. Such operations may be interventions, work-overs or subsea maintenance that is dependent on vessels or rigs. Other indirect sources related to offshore oil and gas processing of oil and gas include helicopter service and waste management. Helicopter services are used to transport employees to and from installation. Waste management onshore can also be a relevant source. Emissions from waste will naturally be dependent on type of waste and how it is handled. Additional sources may also be present, depending on the specific installation.

Marine activity

Emissions from marine activity will be dependent on both type of vessel used, type of intervention and time aspects of which the vessel is used for different activities.

Intervention vessels

Interventions is a general term of dealing with a range of problems inside the well, such as sensor fail, leaks, plugging, moving part, wear and tear. Interventions can be categorized as light and heavy. In light well interventions (LWI), an intervention tool is lowered into the well while the pressure is contained at the surface. LWI is also called riserless light well intervention (RLWI). LWI offshore require specialized vessels and both slickline, wireline and coiled tubing interventions fall into this category. Heavy interventions require killing the well by stopping production in the formation, before interventions can be done. This is for example necessary when parts of the well construction must be changed due to damage or fatigue [50].

Inspection, maintenance and repair vessels

Inspection, maintenance and repair (IMR) vessels are used for various non-intrusive operations related to subsea fields. Inspection findings drive the more complex jobs. Maintenance activities include the replacement of items such as control modules as well as the regular cleaning and clearing of subsea assets. The repair job-types include restorations and modifications, which are job-specific and incorporate substantial engineering input. The operations are most commonly performed by using remotely operated vehicles (ROVs), a module handling system and an active heave compensated crane. IMR vessels are generally speaking a level below LWI vessels, in form of size and capability [51].

Supply vessels

Supply vessels are used for everything that has to be transported to or from offshore installations.

2.4.4. Factors that affect emissions

There have historically been assumed that emission to air is linked to production development. However, this assumption is less relevant today as emissions have been proven to be strongly linked with energy demand [32]. The International Association of Oil & Gas Producers (IOGP) reported that the following factors affect the quantity of gases emitted from petroleum industry operations [52]:

- Distance to the market
- Gas-to-oil ratio
- Reservoir and field characteristics
- Emission controls
- Production techniques and methods for increased oil recovery

- Regulatory and contractual aspects
- Age of field

This is further supported by the NEA [53], which specify that aging fields and transportation can be possible reason for increased emissions unit produced. This is because the reservoir pressure will decrease as hydrocarbons are produced, and will therefore have higher demand for water and gas-injection to stimulate production. This lower reservoir pressure also results in higher demand for compression power.

2.5. Vega – system description

This chapter aims to explain characteristics of the Vega subsea field and how the Vega production is processed on Gjøa. Vega field is a collective name for the subsea fields Vega North, Vega Central and Vega South, which were discovered in 1980, 1982 and 1987 respectively. Vega North and Central are located in block 35/8 and are covered by production license 248 and 248B respectively, whereas Vega South is located in block 35/11 and is covered by production license 090C. An overview of the field is illustrated in fig. 10. Production started in 2010 with Statoil as operator. Wintershall took over as operator in March 2015. Current partners are shown in tab. 4.

Table 4 List of partners involved in the Vega subsea field.

Partners	Share
Wintershall (operator)	55,6%
Petoro AS	28,3%
Spirit Energy Norge AS	7,3%
Neptune Energy Norge AS	4,4%
Idemitsu Petroleum Norge AS	4,4%

Each field have a four-well manifold where two wells per manifold currently have been drilled. The manifolds are connected by pipelines and the total production flows in a common pipeline to Gjøa semisubmersible platform (fig. 11), which is operated by Neptune. The subsea production line is in total 51 km. Between Vega south and Vega central, as well as Vega central and Vega north, there is a 12" production lines (23 km). From Vega north to Gjøa platform there is a 14" production line (28 km). Monoethylene glycol (MEG) is used to avoid hydrate formation in the Vega subsea production pipeline. The water depth of the Vega fields reaches about 375 m [54].'

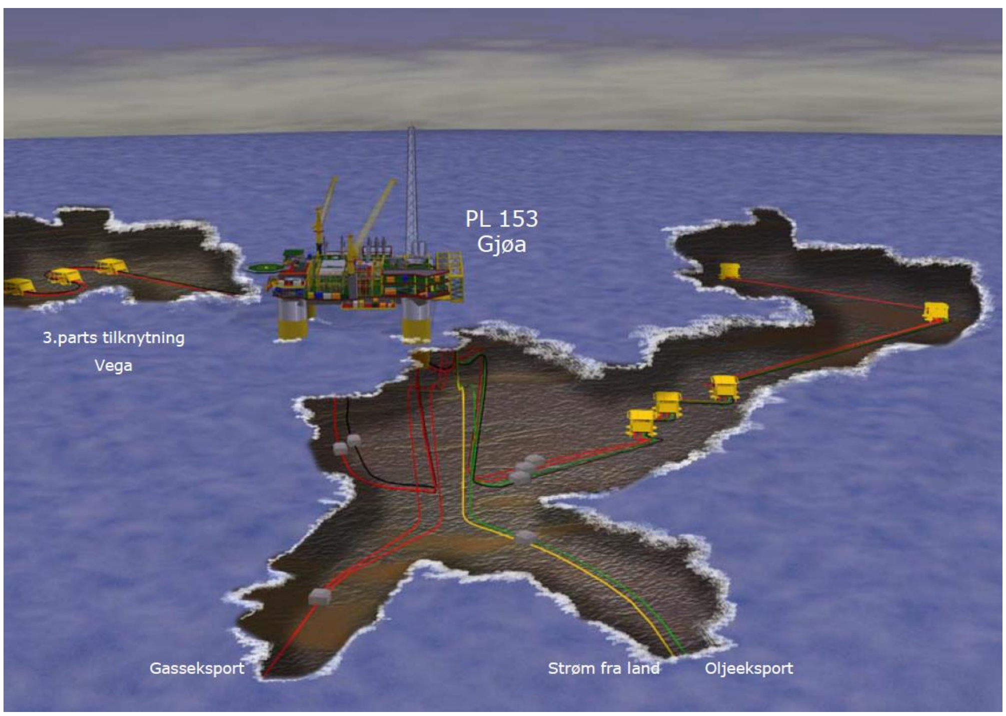

Figure 10 Illustration of Vega and Gjøa subsea manifolds and Gjøa semisubmersible platform [55]

Figure 11 Gjøa semisubmersible platform [55]

Vega South is a gas condensate field with an overlying oil zone, whereas Vega North and Central solely produce gas and condensate. The total Vega production is mainly gas and condensate. Historical production data is shown in fig. 12. The well stream has quite high CO_2 content and produce only small amounts of condensed water [56]. Natural gas is a complex mixture of hydrocarbon and nonhydrocarbon constituents found underground at elevated conditions of pressure and temperature. Natural gas takes gaseous form under atmospheric conditions. Condensate gases have a high content of hydrocarbon liquids and form a liquid phase in the reservoir during the depletion process [57].

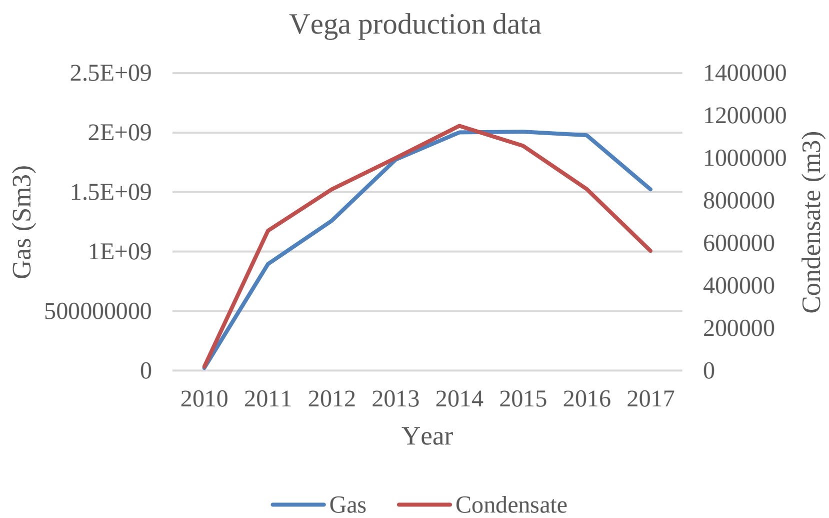

Figure 12 Historical production data for Vega, reported as standard cubic meter (Sm^3) of gas and cubic meter (m^3) of condensate.

2.5.1. GJØA PROCESS

All well streams delivered to Gjøa are separated into gas, oil/condensate and water/MEG in the separators. These three fluids are then handled differently. The gas is recompressed and dried before exported to St. Fergus gas terminal via the Flags transport system on the UK continental shelf [58]. The oil/condensate stream is transported to the Mongstad refinery by the Toll II pipeline [59]. The water and MEG mixture are sent to the MEG regeneration system, where water is separated and discharged to sea and MEG is re-used. Several ulility-systems are also needed for the process to work, e.g. heating and cooling system, chemical injection system, produced water system, fuel gas system, water systems, hydraulic system and electronic system [55].

Separation system

The separation system handles the well stream delivered directly from the subsea manifolds. All separators on the Gjøa platform are designed as three-phase separators, but one is operated as two-phase separators. This system is central for understanding how the well stream separates when it enters the platform, and which processing units are dedicated to oil, gas and water processing. As Vega and Gjøa produce different types of hydrocarbons, the separation process differs slightly. This is illustrated in fig. 13.

Vega have two dedicated separators. Vega 1. stage separator is operated as a two-phase separator, where gas and liquid are separated. Vega. 2. stage separator is operated as a three-phase separator, where the gas, condensate and a mixture of condensed water and MEG are separated. Water rich MEG is treated in MEG regeneration system to remove water, before it is re-injected to Vega subsea manifold. Gas from both Vega separators is analyzed by fiscal metering and gas chromatography, before it is routed to the gas compression system. It is here treated together with Gjøa gas. Vega condensate is also fiscally metered, before it enters Gjøa 2. stage separator [60]. Fiscal metering means that the measurements are used within sale and estimation of taxes or other fees.

Gjøa produce both from a gas manifold and an oil manifold. Gjøa gas manifold deliver production to Gjøa 1. stage separator. This is operated as a two-phase separator, where the gas is routed to gas recompression system. Gjøa gas is not metered separately. Fiscal metering is instead done upstream export gas pipeline. Gjøa gas production can then be calculated as Vega gas production already has been metered. The Gjøa oil is flowing to Gjøa 2. stage separator, where it is mixed with Vega condensate. Gjøa 2. stage separator is operated as a three-phase separator. Gas is routed to the gas compression system, oil/condensate to Gjøa 3. stage separator, and water to the produced water cleaning unit. From Gjøa 3. stage separator, also a three-phase separator, oil/condensate is delivered to the oil export system, gas to the recompression system and water to the produced water system for cleaning [60].

This is a simplified description, which explains only the main well streams. There are several recycling routes back to the separation system, as unseparated liquid hydrocarbons are collected from various parts of the process, e.g. produced water system, MEG regeneration system, flaring system, fuel gas system and gas-recompression [60]. This makes the actual production balance between Vega and Gjøa more complicated, as it is difficult to predict the share of recycled hydrocarbons which originated from Vega or Gjøa manifolds.

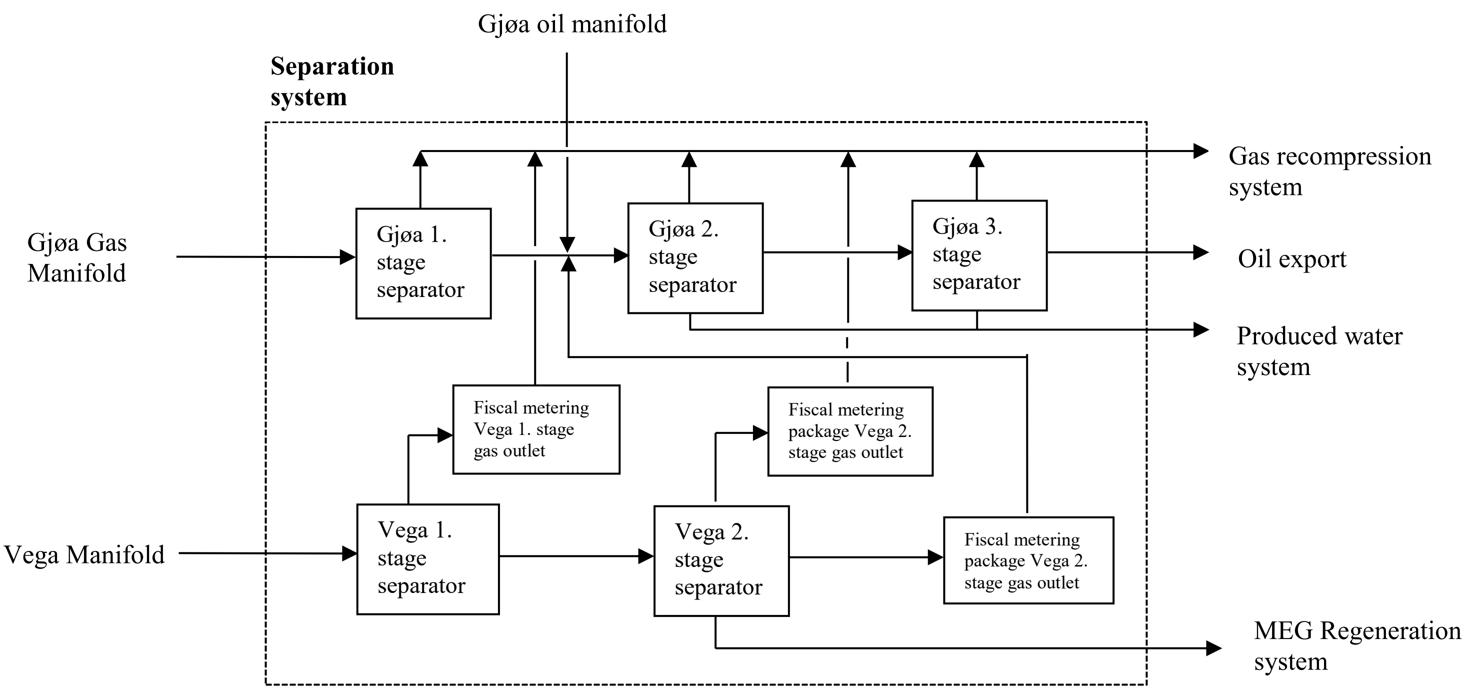

Figure 13 Simplified illustration of the separation system. Adapted from Neptune internal system descriptions and operational procedures (SO-documents) [60]. MEG = Monoethylene glycol.

The gas process system is the most energy demanding and emission intensive part of the Gjøa system, due to the gas turbine used for the gas export compressor. The gas system will be explained more in detail in the following sections. Lastly, the flare and venting system will be described.

Gas processing

The gas must be recompressed and dehydrated with TEG to meet the requirements of the FLAGS pipeline. The units included in this process are illustrated in fig. 14.

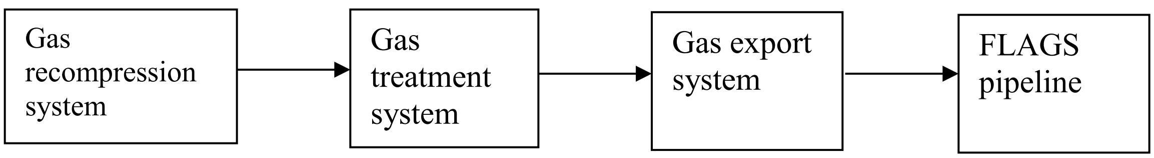

Figure 14 Units included for processing of Gjøa and Vega gas [60].

Gas recompression and gas treatment

The pressure in the separators is lowered by each stage, increasingly allowing dissolved gas to escape from the liquid. The gas is then recompressed to meet the operational pressure in the gas treatment system, which is 64 barg. The process can be operated in high pressure (HP) mode, low pressure (LP) mode and low-low pressure (LLP) mode, depending on the gas pressure from the well. It was produced in HP mode from start-up in 2010 to October 2015, when the gas from the 1. stage separators held high enough pressure to directly flow to the gas treatment system. As well pressure decreases during production, the operation pressure in 1. stage separators has to be decreased as well. The process has therefore been operated in LP mode since October 2015, when the pressure in the 1. stage separators were reduced to approximately 29 barg. The shift to LLP mode is expected to happen in April 2020, where the 1. stage separators will be operated at approximately 19 barg. The gas recompression system is therefore separated in two parts.

Part A compress gas from approximate atmospheric pressure to 19 barg, which is the operational pressure of Gjøa 3. stage separator and Vega/Gjøa 2. stage separators respectively. Part B compress the gas from 19 barg to 64 barg. All compressors in the recompression system are driven by electrical power from shore. The gas recompression system also receives recycled gas from MEG regeneration, TEG regeneration and produced water system at atmospheric pressure. Triethylene glycol (TEG) is used for gas dehydration, an essential part of the gas treatment system. The gas must contain less than 35 volume ppm water in order to meet demand for the gas export pipeline [60].

Gas export

The gas export system receives gas from the gas treatment system. The purpose of the gas export system is to deliver gas with correct temperature and pressure to the existing FLAGS-pipeline between Brent and St. Fergus. The gas is delivered to the gas export system from the gas treatment system at approximately 60 bars. The gas is then compressed by a gas-turbine driven compressor and enters the gas export pipeline from Gjøa with a pressure of 150 barg and temperature of 53 °C. The gas turbine is equipped with a waste heat recovery unit (WHRU), which is used for the MEG regeneration unit. A small stream is diverged to the fuel gas and Gjøa gas lifting system. Note that Vega don't have gas lift injectors, this system is only used for Gjøa. The lifting gas is not included in the export gas fiscal measurements. Fuel gas is included in this fiscal metering system, but also metered individually. Exported gas than then be calculated [60].

Flaring and vent system

The main purpose of the flaring and vent system is to safely collect and deposit hydrocarbons from Gjøa facility from the following sources;

- Flaring of surplus gas

- Blowdown valves (BDV) blowdown/pressure release of the process
- Rupture discs
- Safety valves
- Vent from atmospheric equipment (e.g. tank or compressor seal)

The system consists of three components; high pressure (HP) flare, low pressure (LP) flare system and atmospheric vent. HT and LP flare are equipped with liquid separator, where liquid hydrocarbons are recycled to Gjøa 2. stage separator. Gas recovered from HT flare system is sent to 3. stage separator [55].

Marine activity related to Vega

Supply vessels are continuously used for delivering chemical, food, utilities etc. to the platform. The vessels are based in Florø and the operating companies report fuel consumption to Neptune. LWI operations have in four previous occasions been performed on Vega wells, and more operations will probably be done in the following years. Fuel consumption and emission for these operations are only reported to the NEA as petroleum activity when the vessel has well control. IMR vessels are regularly used, however, emissions are not reported to the NEA since the vessels don't take over well control in these operations. The frequency of these operations and the fuel consumption can be found in Wintershall internal fuel reports but a systematic reporting practice is not in place. Specifications of vessels used for Gjøa and Vega are listed in Appendix 4.

2.5.2. Electricity consumption

Gjøa has installed electrical power from shore and several equipment are therefore driven by electricity Power from shore is assumed to be 'green' in the Norwegian petroleum industry, and no emissions from this electricity consumption are therefore reported to the NEA. Neptune performed an energy review for the 4th quarter in 2014 [61].

Here, specific energy uses were established for the different equipment on Gjøa. Even though this data is taken from a short time period, it is used as an approximation of the general energy consumption of Gjøa for the matter of this thesis. Both fuel gas, electricity and diesel are used as energy source on Gjøa. Their relative energy consumption 4th quarter in 2014 is shown in fig.15.

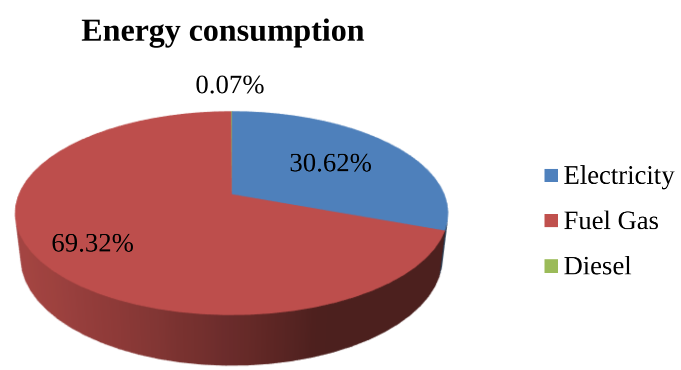

Figure 15 Electricity, fuel gas and diesel consumption from 4th quarter 2014, from Neptune internal documents [61].

Despite that fuel gas only is used for the gas turbine, this makes up approximately 70% of Gjøa's total energy demand. Electricity provides energy for most of the remaining 30%, as diesel is estimated to provide only approximately 0.1% of the energy demand. Diesel is used for fire pumps, essential generators and emergency generators [60].

The report classified 16 equipment with the highest energy consumption as "significant" energy consumers. The energy consumption and average efficiency for each of these equipment can be found Appendix 3. 525 equipment were regarded as "non-significant", due to their low energy consumption. The energy consumption from the 4th quarter of 2014 related to significant and non-significant equipment's is illustrated in fig. 16.

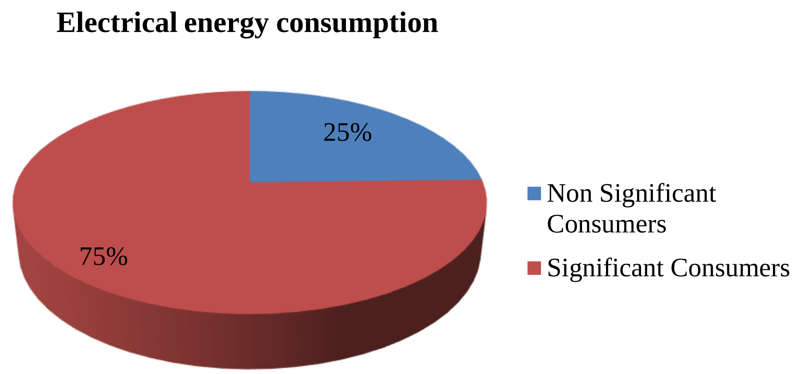

Figure 16 Gjøa's total energy consumption in 4th quarter 2014 for significant and non-significant equipment, from Neptune [61].

2.5.3. EMISSION MEASUREMENT AND ESTIMATION ON GJØA PLATFORM

Several measurements are taken on the Gjøa platform for various reasons. An overview of important metering systems and analysis stations are shown in Appendix 1. Measurements and analysis results relevant for environmental reporting are transferred to NEMS Accounter, either automatically or manually. All calculations related to emissions factors are done in NEMS Accounter. Complete and quality assured emission data is finally transferred to EEH for the yearly emission report.

Emission factors

Emission from combustion sources are calculated as the product of a chosen emission factor (EF) and the activity factor, e.g. the fuel consumption, for a given time interval. For the petroleum sector, it is common practice to use emission factors given by NOROG (tab. 5). The reporting system used in Neptune and Wintershall (NEMS) also include National Greenhouse Account Factors (NGER) in the software's emission factor catalogue.

Table 5 Emission factors given by the Norwegian oil and gas association's guidelines for emission reporting [30]. nmVOC = non-methane volatile organic compounds

State	**Combustion Unit**	**CO_2 (kg/kg)**	**NO_X (kg/kg)**	**CO (kg/kg)**	**N_2O (kg/kg)**	**CH_4 (kg/kg)**	**nmVOC (kg/kg)**	**SO_X (kg/kg)**
Liquid	Turbine	3,17		0,0007			0,00003	0,0028
Liquid	Engine	3,17	0,053	0,007	0,0002		0,005	0,0028
Liquid	Boiler	3,17	0,016					0,0028
Liquid	Well testing	3,17	0,0037	0,018			0,0033	
Gas	Turbine			0,0017	0,000019	0,00091	0,00024	
Gas	Flare	3,73	0,0014	0,0015	0,00002	0,00024	0,00006	
Gas	Well testing	2,34	0,012	0,0015	0,00002	0,00024	0,00006	

Field or equipment specific emission factors

Field or equipment specific emission factors are often given by vendors that delivers the system. There are also some methodologies that can be applied if certain information is available. If the carbon content of a fuel is known, CO_2 can be calculated based on the assumption that all carbon atoms in the fuel will be oxidized to form CO_2 [30] [47]. Complete combustion is assumed under such calculations. The chemical equation for this combustion process is shown in chapter 2.4.1.

CMR-tool is an excel calculation model that is used to calculate CO_2 factor for flares. CMR tool use input data related to flare type, gas composition and measurement uncertainties to calculate flare-specific CO_2 factors. CMR-tool is commonly used among operators across the NSC [55].

Cold venting and fugitive emission estimations

The methods used on Gjøa for emission quantification for cold venting and fugitive sources (CH_4 and nmVOC) are shown in tab. 6. These methods were suggested from the NEA, based on their latest research [45].

Table 6 Sources with respective fate and methodology identified on Gjøa [60].

Source	Fate	Methodology
Gas freeing of process plans	Flared	Annual vented process volume
Gas analyzers and test/sample stations	Recycled	Data from supplier
Small gas leaks/fugitive emissions	Vented	Emission factor
Produced water treatment – discharge caisson	Vented	Calculated pressure volume
Flare gas not burnt	Vented	Indirect measurements
MEG regeneration	Vented	MultiProScale

3. CASE STUDY – FLARING SCENARIOS

A case study was included in this master thesis to give an example of how the inventory model can be used. The current MEG regeneration system has a limited water handling capacity. MEG must be injected into the subsea manifold by a 50:50 volume ratio to the produced water. This is to avoid hydrate formation in the subsea production pipelines. The formation of hydrate is dependent on amount of water present in the well, temperature and pressure. This principle is shown in the fig. 17.

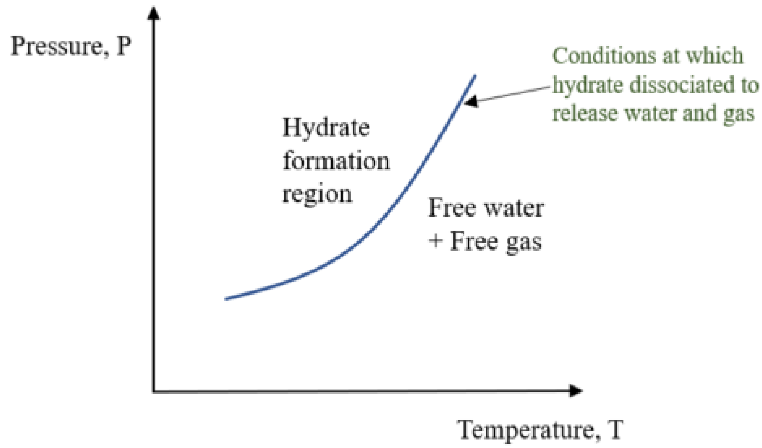

Figure 17 Typical hydrate formation curve [62].

MEG is injected continuously to avoid hydrate formation under unplanned shut-downs. For planned shut-downs, the situation can be controlled in advanced. The wells are expected to produce more formation water as the field is maturing. If Wintershall wants to produce the reserves after the limit of the MEG regeneration system is reached, the risk of hydrate formation must be handled. The possibilities that are currently being investigated include using different kind of chemicals that extend the time-period of which hydrate formation occur under unplanned shut-downs. The hydrate formation risk is therefore linked with the length of unplanned shut-downs. The only factor Wintershall can control during unplanned shutdown is the pressure. This can be done by depressurizing the pipeline by flaring gas. It is estimated that 500 000 Sm^3 gas must be flared for sufficient depressurizing per blow-down, i.e. per unplanned shut-down [56]. This case study will evaluate how different flaring scenarios will affect the final GHG intensity of Vega.

4. ANALYTICAL METHOD

The ISO methodological framework of LCA was adapted by a bottom-up approach to fit the life cycle of the Vega subsea field. Goal and scope is firstly described, followed by method for inventory modelling, impact assessment and interpretation. As only GHG emission was included as impact category, this study was more an LCI than an LCA. The term LCI is therefore used synonymously with inventory model in the following sections.

4.1. Goal and scope

As earlier stated, the goal and scope are crucial in the LCI methodology due to the unavoidable subjectivity that follows such analysis. It cannot be stressed enough that LCI results always should be understood according to their goal and scope.

4.1.1. Goal

The goal of this study was to quantify and differentiate GHG emission that result from activities related to Vega production, which are operationally controlled or can be influenced by Wintershall and/or Neptune. Both direct and indirect emission sources were included. The intended use of this model was to give an overview of the current situation with respect of emission to air and provide a tool that can quantify how operational modifications or changes will impact these emissions. This was regarded as the first step of implementing life cycle thinking in Wintershall, and possibly more sophisticated sustainability tool for environmental management in the future. The study emphasized emissions defined as GHG by the IPCC, since climate change was recognized as the main environmental issue from offshore oil and gas production and processing. However, emission of non-GHGs described as significant in industry reports and electrical energy consumption were also included in the inventory model. This was done to evaluate future possibilities of including impact categories other than GWP.

4.1.2. Scope

Several aspects had to be considered when deciding the scope of this thesis. LCI as a methodology encourage to include as many aspects of the life cycle as possible. However, this study only considered activities directly or indirectly controlled by Wintershall. The scope was therefore naturally narrowed down to offshore production and processing, and the indirect sources which are linked to this part of the operational phase. Upstream production and manufacturing related to both direct and indirect sources were not included. As a result, this analysis represents only a part of the complete value chain. This is illustrated in fig. 18.

The main argument for this choice was that activities included should be on a level that Wintershall can influence and possibly improve. Additionally, the operational phase has been reported by the NEA to account for approximately 90% of all emissions from the total value chain (chapter 2.3.1.). It was therefore reasonable to expect that major emission sources could be found inside the scope defined for this thesis.

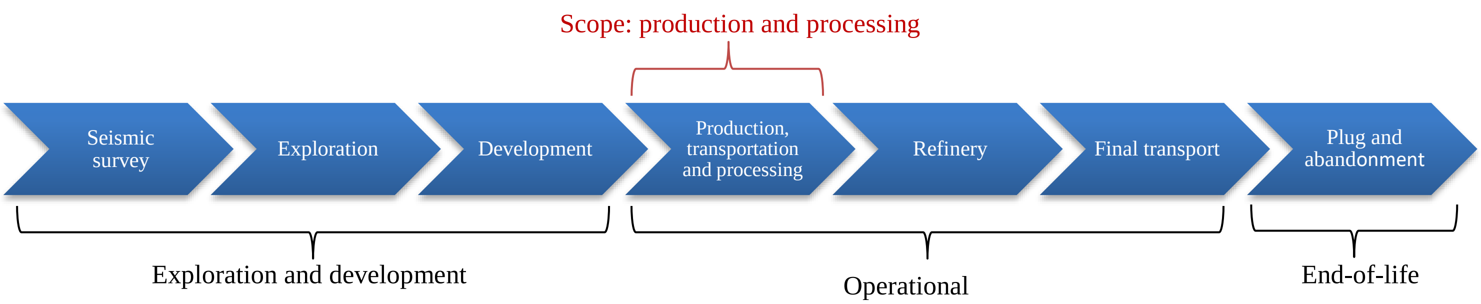

Figure 18 Illustration of scope seen out of the total value chain of Vega.

Product system

The production system and system boundary were identified as shown in fig. 19. System description in chapter 2.5. was the basis for this flowchart. Recycling of hydrocarbons that happen within the Gjøa process are not included in fig. 19 nor in the LCI.

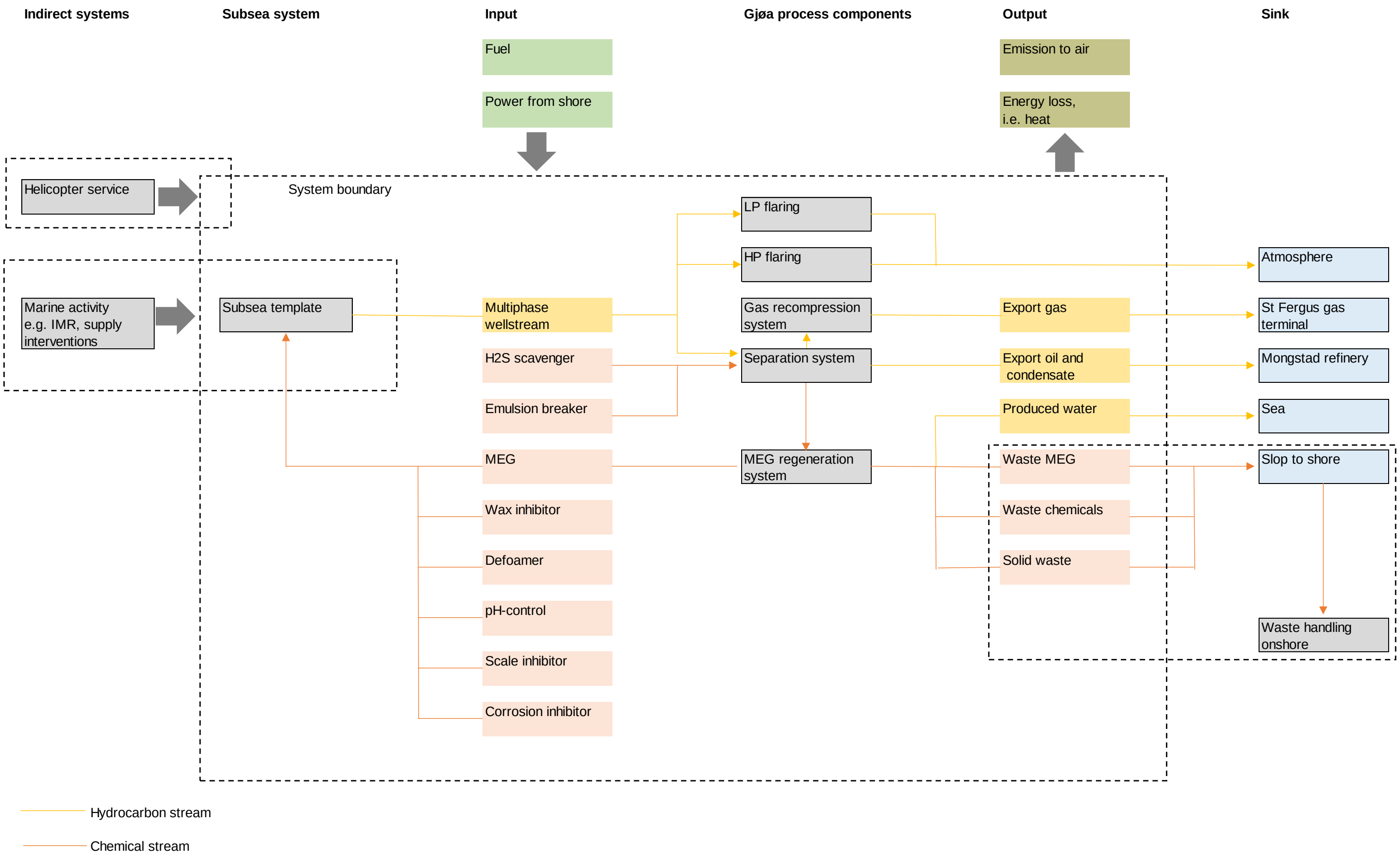

Figure 19 Flowchart of Vega product system. Made in cooperation with Trine Mia Kristiansen Ternø [63].

System boundary

The system boundary was set from the subsea template to export pipeline, where the hydrocarbons physically leave Gjøa platform. Only sources within this part of Vega production phase were included. Hence, this was a cradle to gate LCI scenario seen out from the operational phase. Unit processes was divided into components which comprised the lowest level of where data was available. The unit processes identified within the system boundaries, and their respective components and sources is shown in tab. 7.

Table 7 Identified unit processes, components and sources for the Vega field, HP = high pressure, LP = low pressure, MEG = monoethylene glycol, LWI = light well invetvention, IMR = Inspection, maintenance and repair.

Unit process	Component	Source
Gjøa process (direct)	HP/LP flaring	Flaring (LP and HP)
		Flare gas not burnt
	Gas compression system	Gas turbine
		Gas freeing from process plants
		Leakages in the process
	Fire pumps	Diesel engine (fire pumps and emergency generators
	MEG regeneration system	Gas freeing from MEG regenerator
	Produced water system	Gas freeing from outlet caisson in produced water system
		Fugitive sources
Marine activity (indirect)	LWI vessels	Fuel oil engine (vessel have well control)
		Fuel oil engine (vessel don't have well control)
	IMR vessels	Fuel oil engine (vessel don't have well control
	Supply ship vessels	Fuel oil engine
Other indirect systems	Helicopter	Jet engine
	Waste management	Unspecified

Time-period

The time-period of the inventory was from the field came into production (2010) up to last reported year (2017). Hence, this was a retrospective study. More specifically, production start was defined as when the wells were ready to produce, and the first hydrocarbons was delivered Gjøa for processing. Drilling and completion was not included in this life-cycle, as it is a part of the development phase.

Functional unit

The functional unit used was one giga joule (GJ) worth of hydrocarbon fluid delivered to the oil and gas export pipelines. This unit explained the function of the system (provide energy) and could easily be converted to e.g. joule or other forms of energy. Net calorific values for Vega production values collected from NEMS Accounter was used in this thesis and listed in tab. 8.

Table 8 Net calorific values for Vega and Gjøa production, expressed as giga-joule per standard cubic meter (GJ/Sm^3).

Production	**Net calorific value (GJ/Sm^3)**
Vega and Gjøa gas	0,0414
Vega condensate	33,9750 (2010-2012) 38,5000 (2013 →)
Gjøa oil	36,7625 (2010-2012) 33,7408 (2013) 33,4556 (2014) 33,37138 (2015 →)

Moreover, conversion factors given by the Norwegian petroleum directorate were used in this thesis (tab. 9), where 1 ton oil equivalent (o.e.) = 42 300 mega joule (MJ) = 42,3 GJ [64].

Table 9 Conversion factors given by the Norwegian petroleum directorate [64], GJ = giga-joule, o.e. = oil equivalence.

Production volumes	**Sm^3 o.e.**	**Ton o.e.**	**GJ**
1 Sm^3 Vega gas	0,001	0,00084	0,0355
1 Sm^3 Vega condensate	1,0	0,84	35,53
1 Sm^3 Gjøa oil	1,0	0,84	35,53

Emission factors

A hierarchy principal inspired by NOROG was employed in this thesis. NOROG encourage the use of field and equipment specific emission factors [30]. If specific emission factors are unavailable, emission factors given by NOROG were used. For sources not included by NOROG, NGER emission factors were used. The hierarchy was therefore;

1. Field/equipment specific emission factor (EF_{FS})
2. Emission factors given by NOROG (EF_{NOROG})
3. Emission factors given by NGER (EF_{NGER})

This principle was chosen to be consistent with the current existing emission reporting practice in the Norwegian petroleum sector. Breaking this principle would in some cases have led to different emission factors being used for the same vessel, which again would have led to inconsistencies.

Allocation method

Allocation could not be avoided for the common emission sources for Vega and Gjøa. This applied for emission related to Gjøa process facility and use of supply vessel and helicopter services. The allocation strategy was to reflect the physical relationship between Vega and Gjøa production in a way that could be linked to energy usage. Another part of the strategy was to increase the system detail as far as possible. This was done to decrease aggregation of emission sources and hence, reduce uncertainties related to the allocation procedures. The detail level was restricted to available data.

4.2. Method for inventory modelling

This section aims to explain the practical procedures of how the inventory model was developed. This includes data collection, use of emission factors and allocation keys and how the model was categorized. Excel was used as software for the inventory. The excel sheet can be found in Appendix 5.

4.2.1. DATA COLLECTION

Both primary data and secondary data was used in the inventory. Data collection was done as described in the following sections.

Primary data

Primary data was based on measured fuel and energy consumption, flare rates and emission factors collected from EEH and NEMS. Since EEH data are imported from NEMS Accounter, one would expect these numbers to match. However, some deviations were found. This was mainly because the operators receive feedback from NEA on the yearly report, or discover errors on their own. The errors are updated in NEMS Accounter, but not in EEH or the official reports. Moreover, NEMS Accounter was the preferred data base due to the level of detail needed for this analysis. NEMS Accounter was therefore used as the main data source, with some exceptions;

- EEH was used to collect data from 2010, as NEMS Accounter wasn't implemented as environmental reporting tool in Neptune and Wintershall before 2011.
- Some incomplete data sets were not available in EEH. In these cases, emissions from un-reported years were given by an average of the reported years. This was applied for cold venting and fugitive emissions, supply ships and helicopter.

Cold venting and fugitive emissions have only been reported by the new methodology [45] in 2017. The new quantification methods were regarded as significantly more accurate than the old methods. Values from 2017 was therefore used over the previous years.

Fuel consumption from supply ships and helicopter are internally reported by Neptune in NEMS. Data from 2010-2013 are missing and therefore had to be estimated. Regarding fuel consumption from supply ship, an average value of 2 132 439 kg fuel/year from 2014-2017, was used for the unreported years (2010-2013). The standard deviation was 414 121 kg fuel/year (19,4 %) (fig. 20).

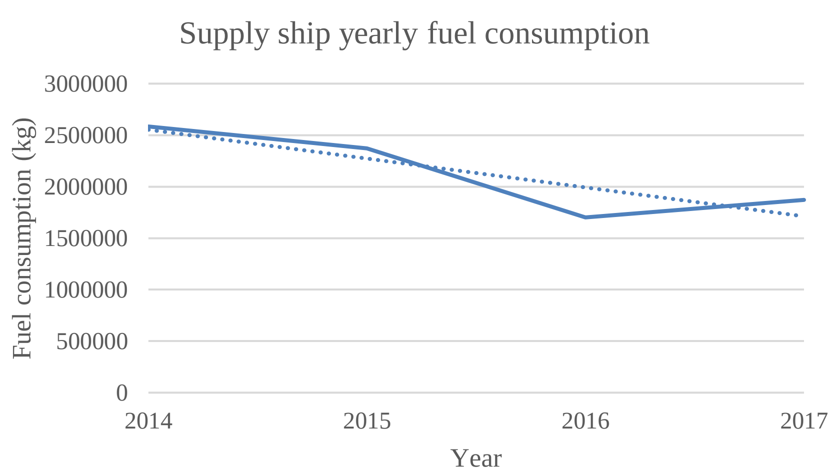

Figure 20 Supply ship fuel consumption (2014-2017) for the Gjøa platform, as reported from Neptune.

The same was done for helicopter service, where an average value of 3 898 kg fuel/year from 2014-2017, was used for the unreported years (2010-2013). Standard deviation was 281 kg (7,2 %) (fig. 21).

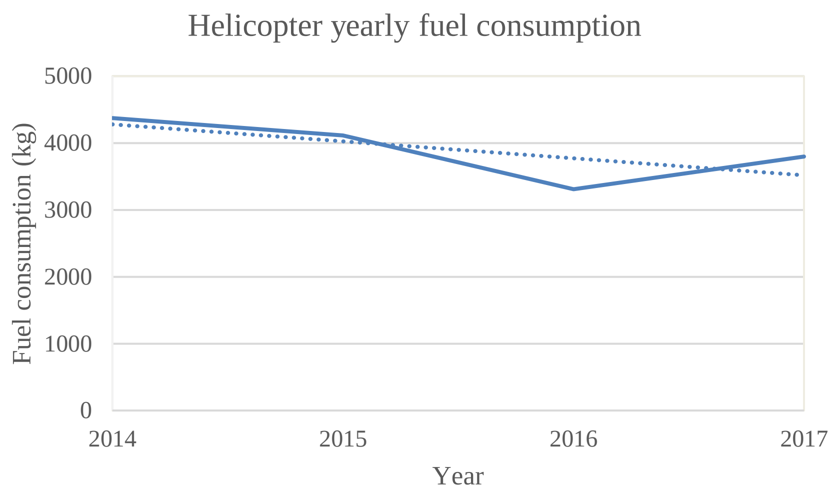

Figure 21 Helicopter fuel consumption (2014-2017) for the Gjøa platform, as reported from Neptune.

Secondary data

Secondary data was only used for LWI vessels outside of well-control (i.e. transit, mobilization and waiting on weather). Emissions were estimated based on statistics given by Island Offshore, which is shown in fig. 22. Island Offshore performed two of the four interventions done on Vega. These statistics were based on one of the Island Offshore operated vessels (Island Frontier). Emissions from IMR vessels and waste management were left out of this study.

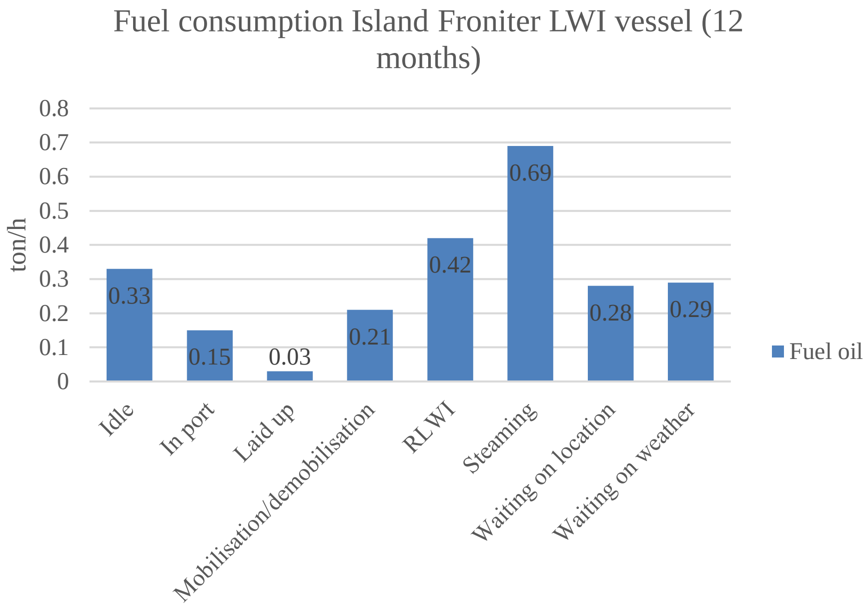

Figure 22 Light well intervention vessel fuel consumption based on measurements taken over 12 months. Data was retrieved from Island Offshore [65].

Fuel consumption of LWI outside well control was estimated per intervention as shown in the tab. 10.

Table 10 Fuel consumption estimation of light well intervention operations outside of well control. Two interventions were performed on Vega in 2015 and hence larger fuel consumption.

Activity	**Hours spent**	**Statistical fuel consumption (ton/h)**	**Estimated fuel consumption (kg)**
Mobilization	20	0,21	4200
Steaming (transit)	18	0,69	12 420
Waiting on weather	3,5 (2014) 20 (2015) 7 (2016)	0,29	293 (2014) 310 (2015) 297 (2016)
		Total	16 914 (2014) 33 551 (2015) 16 918 (2016)

Steaming represents transit to and from the Vega field. Mobilization represents the time used in fueling and changing equipment. Time-estimation was 8-9 hours one way in steaming and 20 hours for mobilization. Hence, total steaming time was set to 18 hours. Waiting on weather was estimated to be 5% of the total duration of the operation. Time-period of the actual intervention, e.g. when the vessel had well control, could be estimated by dividing the reported fuel consumption by the statistical hourly fuel consumption for RLWI (0,42 ton/h).

4.2.2. Use of emission factors

NOROG's emission factor was used for all combustion sources whenever field or equipment specific emission factors were unavailable for all combustion sources, e.g. sources from the Gjøa process and helicopter service. The only exception was helicopter where NGER emission factor was used, as NOROG didn't have factors specific for jet fuel. Most of these cases considered liquid fuel driven engines, beside CO and N_2O emissions from Gjøa gas turbine and flare. NOROG emission profile for engine driven by liquid fuels consisted of 97,4 % CO_2 emission and 2,6 % non-CO_2 emissions. The composition of the 2,6 % non-CO_2 emissions is shown in the fig. 23.

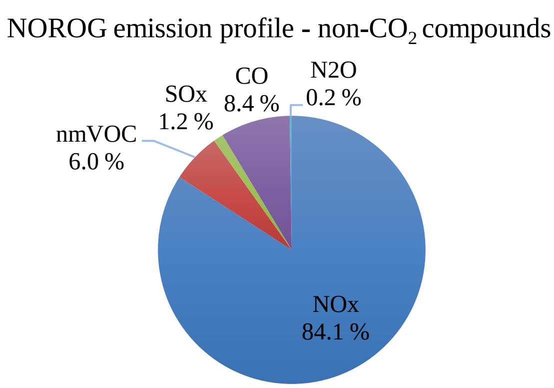

Figure 23 Illustration of non-CO_2 emission profile for diesel engines, when using emission factors given by the Norwegian oil and gas association.

Various emission factors were used for different combustion sources and emission compounds from the Gjøa platform (see fig. 24). This was because field or equipment specific emission factors (EF_{FS}) had been developed for some of the compounds.

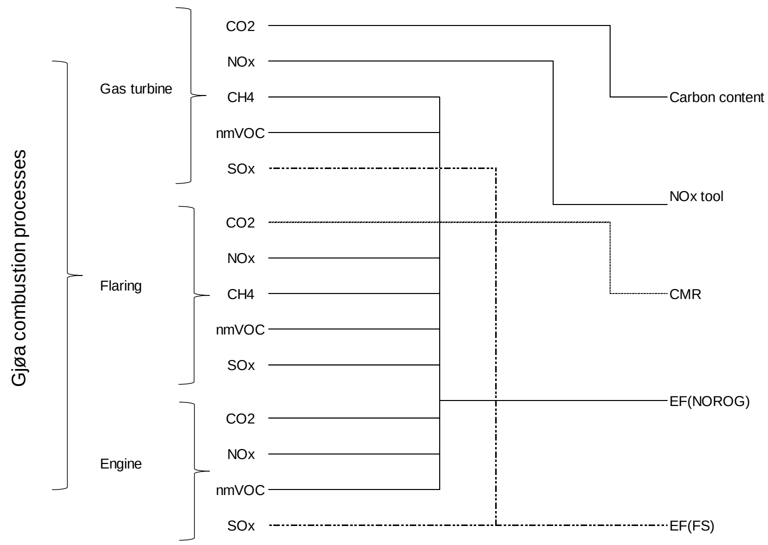

Figure 24 Emission factors used for combustion processes from Gjøa platform, as reported in NEMS accounter. N_2O and CO were consistently derived from emission factors given by the Norwegian oil and gas association (EF_{NOROG}). nmVOC = non-methane volatile organic componds, EF_{FS} = field specific emission factor.

4.2.3. USE OF ALLOCATION KEYS

Allocation keys, (*Ak)*, were developed for Vega/Gjøa allocation purposes (tab. 11). The components within the Gjøa process unit are different for gas and oil/condensate, production-specific allocation keys were needed. It was decided to use volume basis for emission sources specifically related to gas or oil/condensate processing. This was because volume was assumed to be the most important factor to reflect the physical relationship between Vega and Gjøa. Energy basis was used other emission sources that were not devoted solely to gas processing or oil processing.

Table 11 Allocation keys used for the life cycle inventory. Sources for electrical energy consumers are marked with (el.).

Allocation key, *Ak*	Allocation key, *Ak*	Emission contributor, E_x (source)
Total: Ak_1	$Ak_1 = \frac{Energy_{prod}(MJ)}{Tot.energy_{prod}(MJ)}$	Flaring Fire pump diesel engines Flare gas not burnt Fugitive emissions from processing Helicopter Cooling medium pump (el.) Non-significant consumers (el.) Waste management
Gas: Ak_2	$Ak_2 = \frac{V_{gas}(Sm^3)}{T_{gas}(Sm^3)}$	Gas turbine Gas freeing from process plants Gas analyzers and test/samples Leakages in the process Gas compression (el.)
Condensate: Ak_3	$Ak_3 = \frac{V_{cond.}(m^3)}{T_{cond.}(m^3)}$	Produced water treatment Crude oil export (el.)

The allocated emission, *(AE)*, could be found by multiplying emissions from an emission contributor, *(E)*, with the respective allocation key. For example, a Vega/Gjøa common emission contributor related to gas processing, would for a given year, $(E_{,i})$, be allocated to Vega based on allocation factor 2;

$$AE_i = \frac{V_{gas,i}(Sm^3)}{T_{gas,i}(Sm^3)} \times E_i$$

Where $(AE_{y,i})$ represent allocated emission to Vega for a given year, *i*. The sum of emissions from all production year can then be found by;

$$\sum AE_{total} = \sum_{i=2010}^{n} \frac{Energy_{prod}(MJ)}{Tot.energy_{prod}(MJ)} \times E_i + \sum_{i=2010}^{n} \frac{V_{gas,i}(Sm^3)}{T_{gas,i}(Sm^3)} \times E_i + \sum_{i=2010}^{n} \frac{V_{cond.}(m^3)}{T_{cond.}(m^3)} \times E_i + \sum_{i=2010}^{n} \frac{V_{water}(m^3)}{T_{water}(m^3)} \times E_i$$

Where *n* represent the last year included in the survey.

Electrical energy allocation

Electrical energy consumption was only measured on facility level, i.e. all electricity consumption was reported as one value in NEMS. The best available allocation method was therefore based on Neptune's energy report from 4th quarter of 2014. Electrical consumption was allocated to different compartments based on the relationships found in this report. This is summarized in the tab. 12.

Table 12 Gjøa electricity consumption from 4th quarter of 2014

Electrical energy consumers	**Electricity consumption 4th quarter 2014 (MWh)**	**% of total electricity consumption**
Gas recompression system	39964,99	63,03
Oil export pump	4275,94	6,74
Gjøa gas lift pumps	5923,75	9,34
Cooling medium system	1891,40	2,98
Insignificant consumers (sum)	11348,92	17,90

4.2.4. CATEGORIZATION OF INVENTORY EMISSIONS

The inventory was structured as a matrix. Outputs was generated both in horizontal and vertical lines. Total emissions by compound and source was given on the horizontal lines, whereas yearly emission by compounds and compartments was given in vertical lines. This allowed for formula checks, as the sum of emissions should be the same for both horizontal and vertical outputs. Tab. 13 show how emissions were categorized in the inventory.

Table 13 Illustration of how emissions are categorized in the calculation model. nmVOC = non-methane organic volatile compounds, MEG = monoethylene glycol.

Phase	Compartment	Emission compound	Source	
Operational	Gjøa platform	CO_2	Gas turbine	
	Marine vessels	CH_4	Engine	Combustion
	Helicopter	nmVOC	Flare	
	Waste handling	NO_x	Boiler	
		SO_x	Flare not burnt	
		CO	MEG regenerator	
		N_2O	Gas analyzer stations	
			Gas freeing from process plant	Cold venting
			Produced water treatment	
			Leakages in the process	
			Fugitive sources	

4.3. Method for impact assessment

GWP and energy was the only impact categories used for the impact assessment in this LCA study. A time horizon of 100 years and CO_2-equivalent conversions was used as recommended by IPCC. The carbon footprint could therefore easily be calculated by the GWP values given by the IPCC (chapter 2.1.1.). GHG intensity was calculated by dividing Vega allocated GHG emission by total Vega production.

4.4. Method for interpretation

Relevant interpretation checks were done as recommended by ISO 14044 [18] to evaluate the result robustness. This included sensitivity analysis, completeness check and data quality check. Solvertable excel add-in was used for the sensitivity analysis. Sensitivity analysis was used to check effect of allocation methods, choice of emission factor and the case study of flaring scenarios. There was very limited information regarding uncertainties of the data used. Uncertainty analysis could therefore not be conducted.

4.5. Case study

Statistical analysis done by Wintershall expect that the gas pipeline will have to be depressurized 1-10 times yearly due to unplanned shut-downs as the processing philosophy moves away from the MEG-injection. Flaring scenarios of 0-10 yearly pipeline depressurization were therefore used for this case study. The years included in this analysis were 2021-2029. It was assumed the same number of depressurizations each year. Baseline was set by Vega production and emission forecast provided by Wintershall and zero flaring. Each depressurization was estimated to result in the flaring of 500 000 Sm^3 gas. Forecasted production and emission data could not be included due to confidentiality. Sensitivity analysis was used to efficiently check how different flaring scenarios would affect the final Vega GHG intensity.

5. RESULTS

The inventory and interpretation results are illustrated and shortly explained in the following sections.

5.1. Emission of greenhouse gases

The carbon footprint (total GHG-emissions) and GHG intensity of Vega were estimated as 0,290 million tons CO_2-eq. and 0,411 kg CO_2-eq./GJ respectively for 2010-2017. Yearly variations are shown in fig 25.

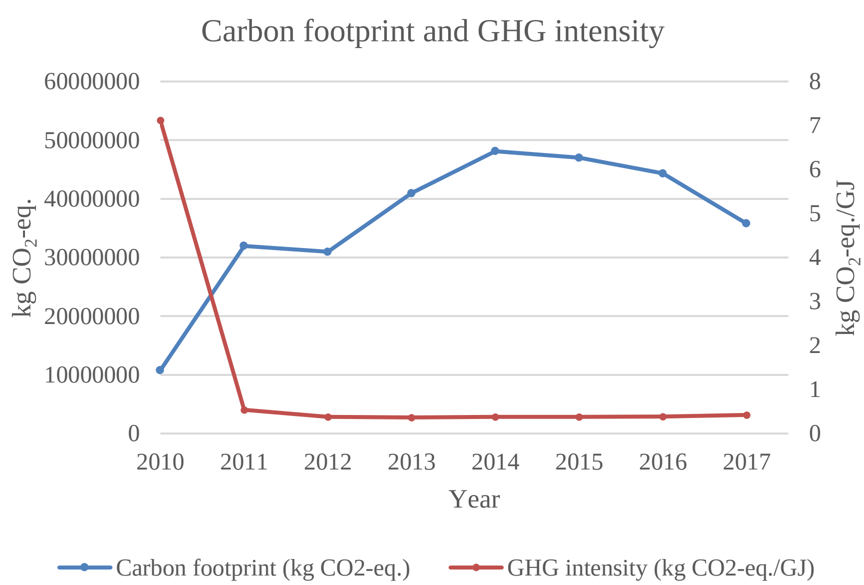

Figure 25 Yearly carbon footprint and greenhouse gas intensity.

From fig. 25, GHG intensity appeared to be quite stable from 2012. Hence, linear (fig. 26) and polynomial (fig. 27) relationships were investigated. GHG intensities from 2010 and 2011 were not included since these values deviated significantly from the other years.

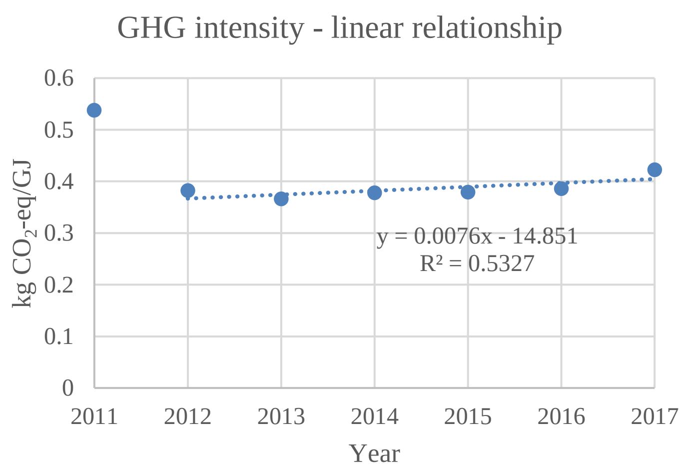

Figure 26 Greenhouse gas intensity linear trendline.

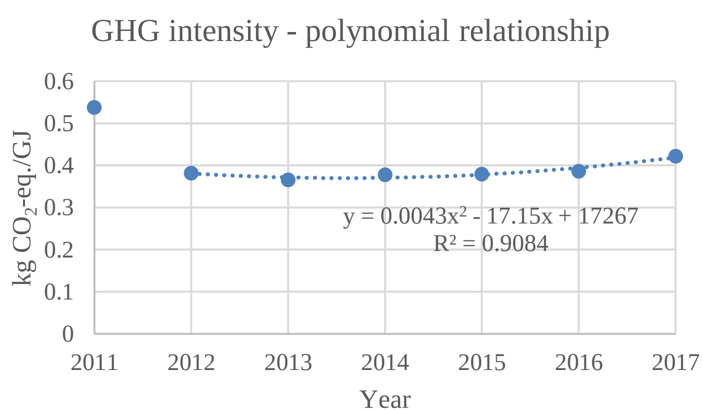

Figure 27 Greenhouse gas intensity polynomial trendline.

GHG intensities from the gas turbine is shown in fig. 28, where Vega allocated GHG intensity is compared with Gjøa allocated GHG intensity and total GHG intensity. A strong polynomial relationship (r^2 = 0,998) was found for Vega GHG intensity.

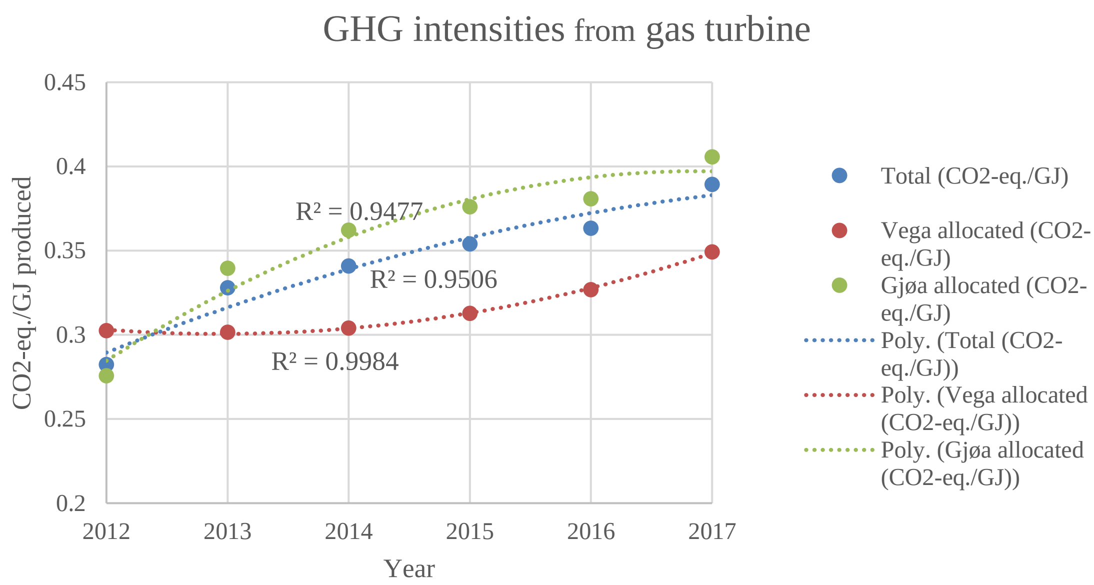

Figure 28 Greenhouse gas intensities from gas turbine.

Vega allocated GHG intensity from the gas turbine was then investigated for Vega gas production only (fig. 29).

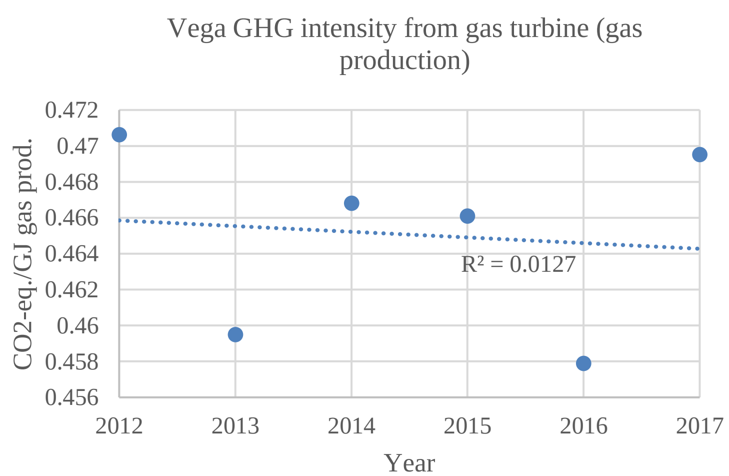

Figure 29 Greenhouse gas emission from the gas turbine per giga joule gas production.

Linear and polynomial trends were plotted for future production years, as demonstrated in fig. 30.

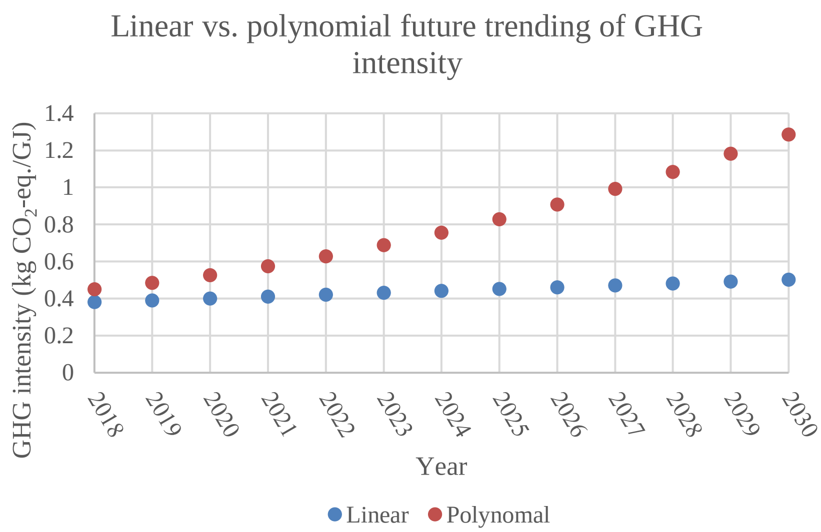

Figure 30 Future greenhouse gas intensity based on linear and polynomial relationship.

5.1.2. GREENHOUSE GAS EMISSION SOURCES

GHG emissions from significant emission sources were quantified as shown in tab. 14. Note that the waste management was not included due to lack of data.

Table 14 Greenhouse gas emission from the identified emission sources. GWP = global warming potential.

Emission source	**GHG (kg CO_2-eq.)**	**GHG %**
Gas turbine	223 714 241	77,2
Cold venting and fugitive emission	29 764 332	10,3
Flaring	17 958 290	6,2
Marine activity	16 017 254	5,5
Fire pump	1 114 375	0,4
Marine activity w. well control	738 333	0,3
Helicopter	617 109	0,2
Total	**289 923 933**	**100**

The total GHG contribution from CO_2, CH_4 and N_2O by mass was calculated as illustrated in fig. 31. Contribution from different sources are illustrated in fig. 32.

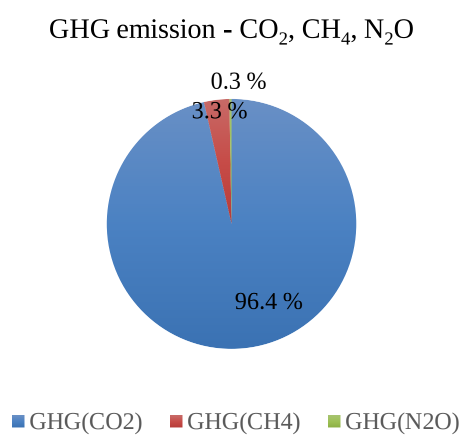

Figure 31 Compound-specific relative contribution to greenhouse gas emission by mass.

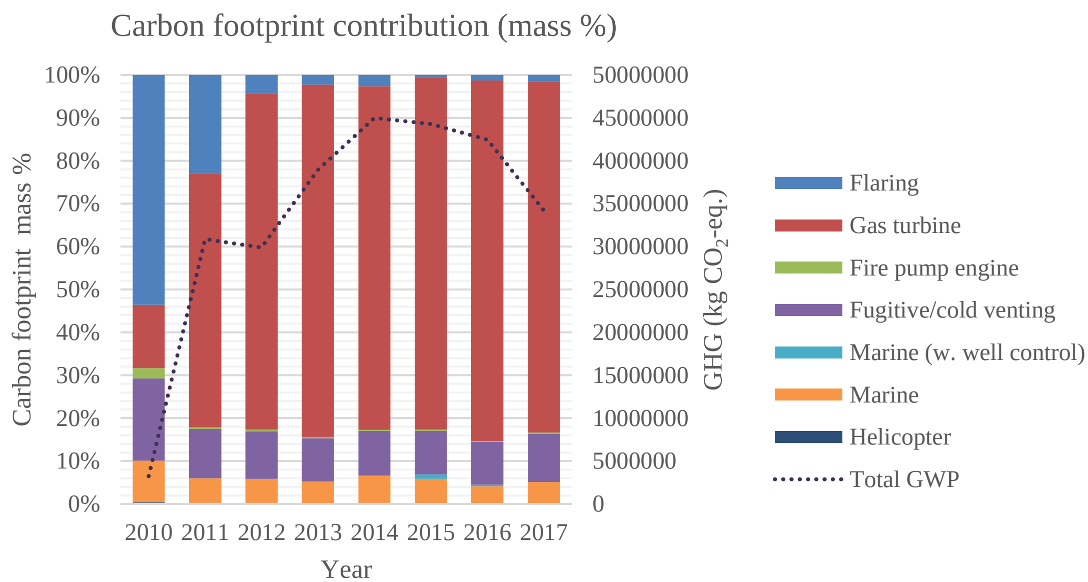

Figure 32 Yearly carbon footprint contribution of different sources relative to total greenhouse gas emission from each year.

Marine activity

As interventions were performed in 2014, 2015 and 2016, these years where used to compare fuel consumption, and hence emission, from the marine activity (fig. 33).

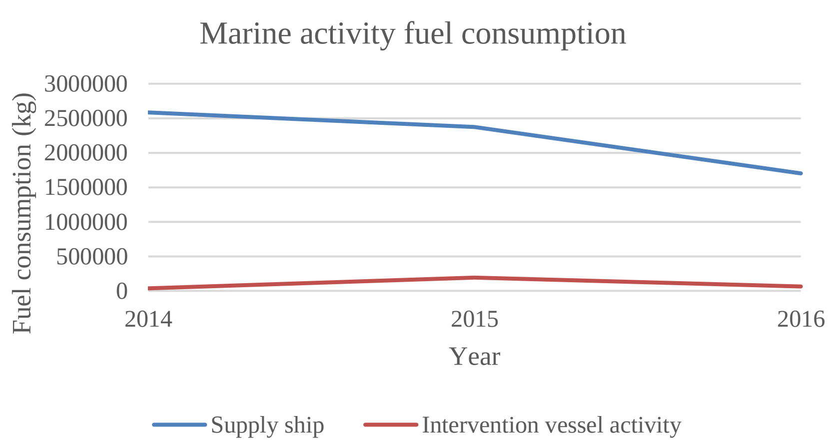

Figure 33 Comparison of fuel consumption from supply ship and intervention vessels from 2014-2016.

5.2. Electrical energy intensity

Overall energy intensity from 2010-2017 was found to be 0,639 kWh/GJ Vega production. Yearly variation is reported in fig. 34.

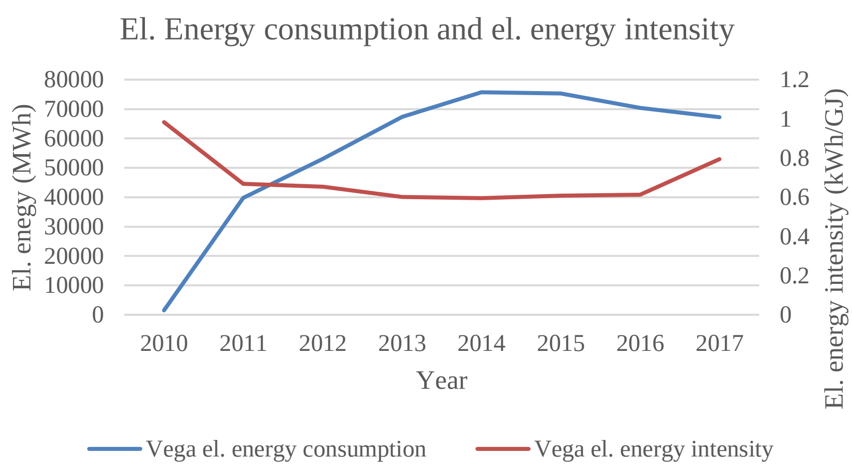

Figure 34 Yearly electrical energy consumption and electrical energy intensity on the Gjøa platform allocated to Vega production.

Monthly consumption for previous years is shown in fig. 35. Monthly data was missing for 2010 and therefore not included. There was not discovered seasonal variations of electricity consumption.

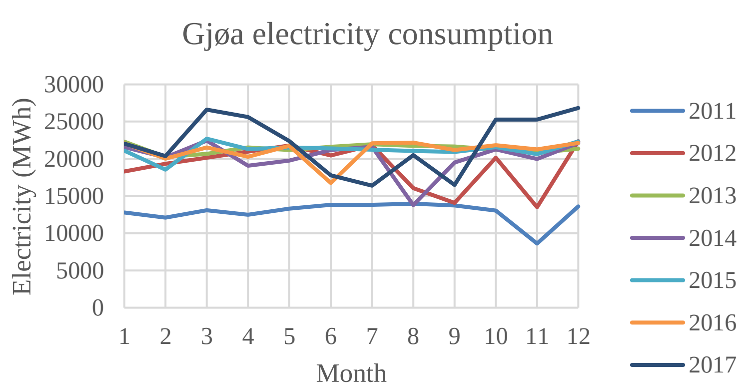

Figure 35 Monthly energy consumption for previous production years.

5.3. Emission of non-greenhouse gases

Emission of non-GHGs (NO_x, SO_x, nmVOC and CO) was calculated to account for only 0,85 mass % of the total emission (fig. 36).

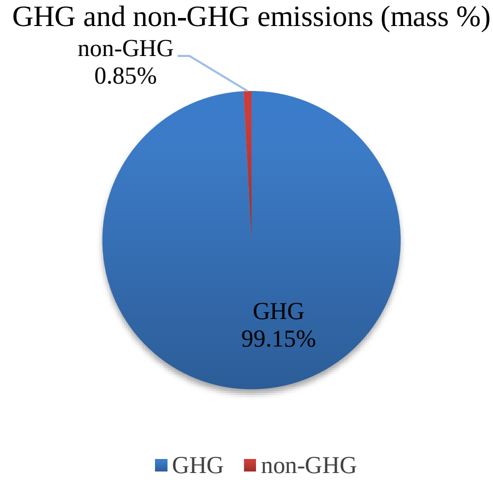

Figure 36 Relative emission of greenhouse gas emission and non-greenhouse gases.

5.4. Interpretation

Relevant interpretation checks as described by ISO are given in the following sections. Correlations between GHG emissions from different sources and production data were also checked.

5.4.1 Completeness check

The completeness check systematically assessed the completeness of data, and whether actions are required. The completeness was evaluated as shown in tab. 15.

Table 15 Completeness check of the life cycle inventory, as recommended by ISO [18]. LP = low pressure, HP = high pressure, MEG = monoethylene glycol, PW = produced water, IMR = inspection, maintenance, repair, NEA = Norwegian environmental agency.

Source	Data availability	Complete?	Required action
Flaring (LP and HP)	X	Yes	N/A
Gas turbine	X	Yes	N/A
Diesel engine (fire pumps and emergency generators	X	Yes	N/A
Gas freeing from process plants	X	No	New methods described by the NEA was only used in 2017 reports. Should be recalculated (this was not done due to time constraints)
Leakages in the process	X	No	
PW treatment	X	No	
Flare not burnt	X	No	
MEG regenerator	X	No	
Fugitive sources	X	No	
Intervention w. well control	X	Yes	N/A
Intervention transit/mobilization	-	-	Not reported. Fuel consumption and emission factors was estimated
IMR operation	-	-	
Supply ship	X	No	Emission factor was estimated. Data from 2010-2013 was missing, and average number from reported years was used
Helicopter	X	No	
Waste handling	-	-	Not reported
X: primary data was available - : no data was available			

5.4.2. Sensitivity analysis

Sensitivity analysis of GHG intensity toward numerical changes in allocation procedures and NOROG CO_2 emission factor for liquid fuel were conducted to illustrate the consequences of errors or uncertainties related to these numbers. Only CO_2 emission factor for liquid fuels given by NOROG was included in this analysis. This was the most frequently used in the inventory and previous inventory results estimated that 96,4 % of the GHG emission resulted from CO_2 (fig. 31). The sensitivity of GHG to allocation keys is illustrated in fig. 37. The degree of sensitivity by percentage change in Ak_2 and NOROG CO_2 factor was as shown in fig. 38 and fig. 39 respectively.

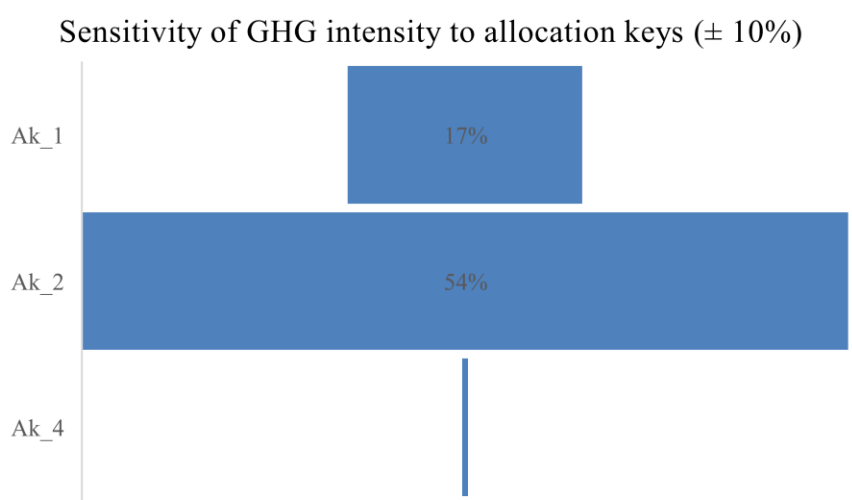

Figure 37 Sensitivity of greenhouse gas intensity to ± 10 % variations in allocation keys. Ak_1 = allocation key 1 (total allocation), Ak_2 = allocation key 2 (gas allocation), Ak_4 = Allocation key 4 (produced water allocation)

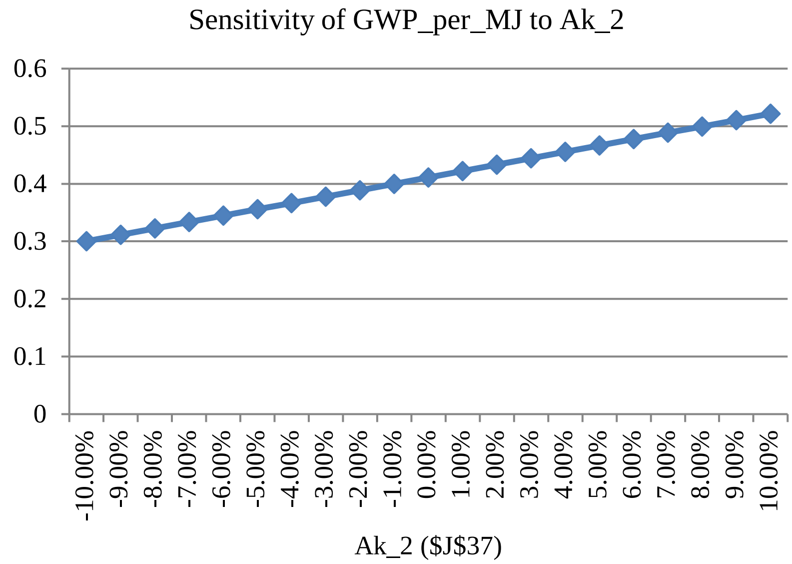

Figure 38 Sensitivity of greenhouse gas intensity to allocation key 2 (gas allocation, Ak_2).

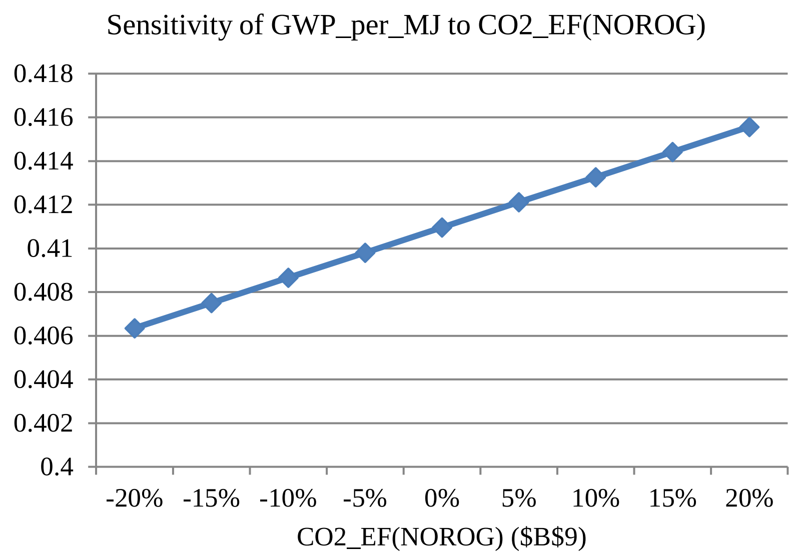

Figure 39 Sensitivity of greenhouse gas intensity to CO_2 emission factor given by the Nowegian oil and gas association (EF_{NOROG}).

5.4.3. Correlations with production data

The GHG emission from gas turbine correlated well with gas production data (fig. 40). No other significant correlations between emission and production data were found. There was, however, found correlation between electrical energy consumption and total production (fig. 41)

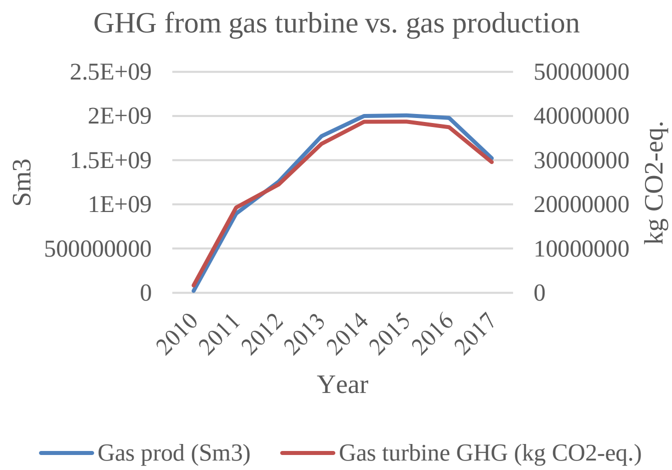

Figure 40 Greenhouse gas emissionfrom gas turbine plotted against gas production data.

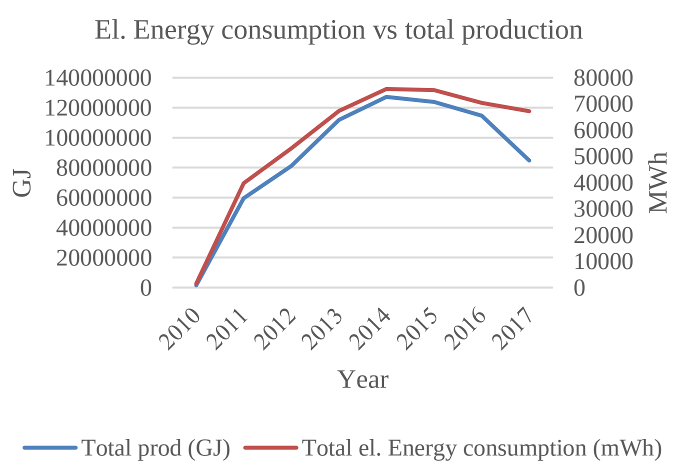

Figure 41 Electricity consumption on Gjøa plotted against production data.

5.5. Case study – flaring scenario

Result from the sensitivity analysis done for flaring scenarios are shown in the tab.16 and fig. 42.

Table 16 Flaring emission effect of predicted Vega greenhouse gas intensity.

Flaring scenario	**Base-line**	**1**	**2**	**5**	**10**
Yearly gas flared (Sm^3)	0	500 000	1 000 000	2 500 000	5 000 000
Vega GHG intensity (kg CO_2-eq./GJ)	0,634	0,644	0,653	0,681	0,727

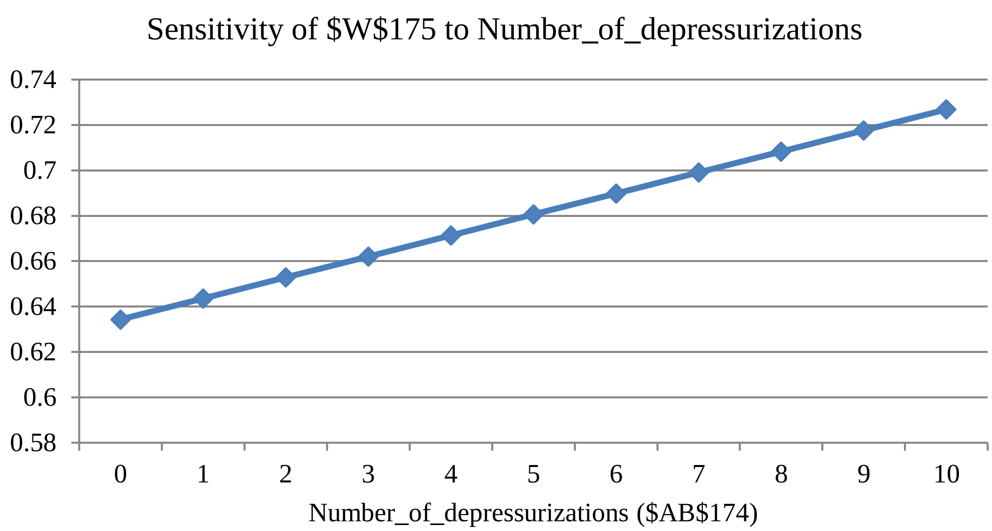

Figure 42 Sensitivity of forecasted Vega greenhouse gas intensity to the different flaring scenarios.

6. DISCUSSION

Many analysts view the "finished" model as a starting point for all sorts of "what if questions" –C. Albright, W. Winston [66].

The carbon footprint inventory model for Vega subsea production is currently able to answer several 'what if' questions. The case study illustrated an example of this. However, other cases can be related to for example operational modifications, reduction potentials, correlation trends, consequences of allocation procedures or data errors. Further details about the carbon footprint inventory results will be discussed in chapter 6.1 The choice of methodology is then discussed in chapter 6.2. A broader perspective is taken in the next part of the discussion (chapter 6.3.), where methodological limitation and further work are evaluated.

6.1. Carbon footprint inventory

The bottom-up inventory modelling successfully differentiated emission sources and components, which was emphasized in the goal of the LCI. As the goal and scope was revised several times, this was an iterative LCI study indeed. This resulted in a mismatch between the original objective of this thesis (chapter 1) and the goal of the LCI (chapter 4.1.1.). The main goal sat by Wintershall was initially to develop a model for quantifying the environmental footprint of Vega with respect of emission to air, whereas the goal of the LCI study was to target carbon footprint as a single-issue method. This was a result of time restriction related to this project and lack of scientific consensus of which impact categories to include in an environmental footprint.

6.1.1. INVENTORY RESULTS

Carbon footprint (total GHG emissions) and GHG intensity for Vega were found to be 0,290 million tons CO_2-eq. and 0,411 kg CO_2-eq./GJ respectively for 2010-2017. The GHG intensity can also be expressed as 17,4 kg CO_2-eq./toe. This is very low compared with the average GHG intensity of 64 kg CO_2-eq./toe given from the NEA [32]. However, this average value include emission from drilling and well testing, which was excluded from the scope of Vega.

The CO_2 accounted for 96,4 % of the carbon footprint, whereas CH_4 and N_2O accounted for 3,3 % and 0,4 % respectively (fig. 31). This corresponds with the industry assumption of low N_2O emission. The low N_2O contribution to carbon footprint was however based on emission factors from NOROG. To increase the scientific grounding of these factors, documentation of how NOROG emission factors are derived, e.g. references to laboratory testing should be included in the guideline.

The GHG intensity is more informative than total GHG emissions from a life cycle point of view. This is because GHG intensity represent the functional unit, or performance, of the system. The yearly GHG intensity is plotted against the total GHG emission in fig. 25. Relative emission contribution of the different sources is illustrated in fig. 32. These two figures combined give a good overview of the carbon footprint. The high GHG intensity in 2010 can mainly be explained by large emission from flaring due to start-up of the field and low production, as shown in fig. 32. GHG intensity appears to be quite stable from 2011 to 2017 (fig. 25). A closer look at the GHG intensity, shows that 2011 deviates from 2012-2017. This is due to flaring, which contributes significantly more to the carbon footprint in 2011 than 2012-2017. One can also see that carbon footprint and production both decreased from 2014-2017. The GHG intensity was slowly increasing, showing that the GHG intensity was influenced more by to the production decrease than the GHG emission reduction.

Trendlines for the GHG intensity from 2012-2017 can be used to evaluate the future GHG emission. A strong polynomial correlation was found for GHG intensity (r^2=0,91) (fig. 27), and a weaker correlation was found for the linear trendline (r^2=0,53) (fig. 26). Similar polynomial relationship (r^2=0,998) was found when analyzing the gas turbine separately from the rest of the system (fig. 28). GHG intensity from the gas turbine was therefore further investigated. It is known that declining reservoir pressure (due to aging field) increase the need for compression power. Hence, the polynomial relationship found for GHG intensity could be due to increased fuel gas consumption per unit gas produced. However, the Vega allocated gas turbine GHG emission per unit Vega gas produced was found to be rather stable (fig. 29). This indicates that the extra compression power needed due to declining reservoir pressure is generated by the electrified compressors on Gjøa. However, further investigations of this assumption could not be done due to time restrictions.

Both total and Vega/Gjøa allocated GHG intensities from the gas turbine with respective trendlines are plotted fig. 28. This figure illustrates how the allocation procedure used in this thesis 'split' the total gas turbine GHG intensity on a facility level into field level, i.e. Vega and Gjøa separately.

The two trendlines found for Vega allocated GHG intensity (linear and polynomial) were plotted as future scenarios in fig. 30. The life-time of Vega was here set to 2030. This year was hypothetically chosen, as the actual forecasted life-time of Vega could not be provided as it is confidential information. In 2030, the polynomial scenario would more than triple the GHG intensity, whereas the linear scenario would maximally reach a yearly GHG intensity of 0,55 kg CO_2-eq./MJ.

6.1.2. SIGNIFICANT EMISSION SOURCES

As expected, the gas turbine was by far the most significant contributor to the carbon footprint (77,2 %), followed by cold venting and fugitive emissions (10,3 %) and flaring (6,2 %) (tab. 15) Interestingly, the marine activity without well-control was identified as a major source with 5,5 % of the total carbon footprint (tab. 15). These emissions were also underestimated, as IMR operations were excluded. The emission from supply ship was dominant compared to intervention, as illustrated in fig. 33.

6.1.3. INTERPRETATION OF RESULT

Completeness check and sensitivity analysis was conducted for result interpretation. The sensitivity analysis was used to evaluate the consequence of the choice of scope definitions, e.g. allocation keys and emission factor.

Completeness and quality of data

Primary data is generally considered more accurate than secondary data [12]. This is particularly true for the petroleum activity across the NCS, where emissions are below the international average [32]. Use of statistics could therefore easily overestimate emissions and lead to inconsistent use of data. Hence, there was not put significant effort into searching for secondary data. The focus was rather to make the method applicable for future use, where comprehensive collection of data for every inventory is unrealistic. Instead of searching for statistical data, internal reporting practice should be changed to include all relevant sources seen out from the goal of the study. As seen from the completeness check (tab. 15), there was only four sources (flaring, gas turbine, fire pump engine and intervention with well control) where primary data was complete. However, these four sources accounted for 84 % of the carbon footprint, mainly due to high contribution from the gas turbine.

Due to the complex gas composition of emission and atmospheric reactions, it is reasonable to assume large uncertainties related the data used for the inventory. The degree of uncertainty is mainly dependent on the estimation technique and emission component. The CO_2 emission from the gas turbine can be regarded as accurate, since the carbon content of the fuel gas is measured by gas chromatography. However, the assumption of complete combustion will slightly overestimate the total emissions, since nmVOC and CH_4 emissions are reported as well. CMR-tool and specific emission factors are likely to be more accurate than generic emission factors, as more input data is used. Significant uncertainties were related to cold venting and fugitive sources. This was because of high uncertainties related to the quantification methods. The emissions were also generalized based on the only year reported based on the new protocols given by the NEA [45].

Moreover, data requirements will be specific to the use of inventory result. For this case study, the model was sensitive enough to respond to the operational change of different flaring scenarios. The data can therefore be regarded as sufficient. However, this may not be the case for another scenario, especially if secondary data is used.

Scope definitions

Scope decisions and assumptions must be discussed to ensure transparency and facilitate future scope improvements. This is a crucial part of life cycle thinking, as the result can vary substantially depending on the person or organization in charge of the analysis.

Emission factors

Various emission factors are available in the literature. To be consistent with industrial practices, NOROG guidelines were used. NOROG encourages the use of field or equipment specific emission factors as far as possible. Due to the absence of specific factors, NOROG emission factor for liquid fuel engine was used for several sources in this thesis (chapter 4.2.2.). Sensitivity analysis showed that an extreme case of ± 20 % variation in NOROG CO_2 emission factor resulted in a 2,4% variation of the GHG intensity (fig. 39). This shows that the GHG intensity of Vega was rather unsensitive, even though this emission factor was frequently used.

Allocation keys

Several strategies could be used for emission allocation between Vega and Gjøa, e.g. energy, mass or volume basis. For gas processing, a volume basis can be justified by regarding the gas processing unit as a closed thermodynamic system. Here, energy consumption is related to work done to the system. The work is hence directly linked with the external pressure applied and the volume change of the gas. Since pressure will be the same for Vega and Gjøa gas production, processed volume could therefore differentiate energy consumption between them. As Vega and Gjøa gas have the same calorific value, the allocation keys would not have changed by using an energy basis. However, this may not be the case for other fields and hence, a volume basis should be used.

The energy required to process oil and condensate in form of heating or pumping power was not as straight forward. Here, other factors than volume could have been relevant, e.g. separation properties, viscosity and density. The same challenge was found for fugitive emission and leakages, where factors such as diffusion properties of the processed fluids could give more correct allocation. However, physical relationship could not be further justified based on available data. Volume basis were also used for the oil/condensate processing system, based on the assumption that this was the most important factor. As processing and oil delivery are covered by power from shore, allocation procedures are irrelevant for the Vega inventory. However, this may not the case for future inventories related to oil and gas production.

Common emission contributors that couldn't be divided into gas process system or oil/condensate process system were allocated on an energy basis. Gas is produced in far bigger volumes than oil and condensate from the Vega and Gjøa fields. A volume basis could, depending on Vega/Gjøa reservoir composition, emphasize gas production more than oil/condensate in an allocation procedure. Energy basis was hence regarded as a more logical choice.

The sensitivity analysis showed that the GHG intensity from Vega production is far more sensitive to Ak_2 than the other allocation keys (Ak_1 and Ak_4). The high sensitivity of Ak_2 can be explained since the highest carbon footprint contribution (gas turbine) was allocated by this allocation key. Ak_3 was only used for electrical energy and therefore will have no effect on the emission inventory at all. This is illustrated in fig. 37. For Ak_2, the variation of ±10 % gave a 54 % difference in the GHG intensity. The same variation would result in 17 % and 0,4 % variation in the GHG intensity from Ak_1 and Ak_4 respectively. Fig. 38 illustrate the sensitivity curve of GHG intensity to Ak_2.

6.1.4. CASE STUDY RESULT

Based on forecasted production and emission data, the GHG intensity over the predicted life-time (2010-2029) of Vega will be 0,634 CO_2-eq./GJ produced. This value is quite high compared to the GHG intensity of 0,411 CO CO_2-eq./GJ found for 2010-2017. There are high uncertainties related to this forecast, but it clearly indicates that the GHG intensity is expected to increase in the coming years. The sensitivity analysis shows that the GHG intensity is likely to increase with approximately 0,009 CO_2-eq./GJ for every extra yearly flaring that must be done due to depressurization of the production pipeline.

The maximum of 10 yearly flaring scenarios would give a GHG intensity of 0,727 CO_2-eq./GJ, i.e. an increase of 14,59 % from the baseline GHG intensity with no extra flaring.

6.2. Choice of methodology

Life cycle thinking was unavoidable in this study, as 'footprinting' originates from LCA [12]. It was prioritized to use real, measured data as much as possible. This was both to reduce uncertainty and ensure understanding of how the numbers are derived. Additionally, there was not access to LCA software through Wintershall or the University of Stavanger. ISO 14040/14044 is generally the most accepted LCA methodological framework and was therefore chosen for the inventory modelling. To adapt the ISO method to this study case, a bottom-up approach described by Mitchell and Hyde was used (chapter 2.2.4.). This approach was developed for industrial processes and allowed for increased detail level of a product system by dividing process units into components. However, this article was published in 1999, and research within LCA has developed significantly since then. Interestingly, Mitchell and Hyde discuss the same issue related to the ISO LCA standard that was experienced during the work of this thesis; the comprehensive and generic nature of the ISO LCA is not easily translated to industrial processes. The bottom-up approach allows customization of the inventory modelling to meet individual needs of an organization. This flexibility was chosen over transparency and comparability which is a major concern by the ISO. This was regarded as a valid choice as the results are intended for internal use in Wintershall only.

6.3. LCA within Wintershall – current and future perspectives

As described by Finkbeiner (chapter 2.1.2.), life cycle thinking, and single-issue methods are the very first step of implementing more sophisticated LCA methods in an organization. It can therefore be argued that this project sat the starting point for using LCA as an environmental assessment tool. This section addresses the methodological limitations and further work required to exploit the potential of LCA within Wintershall.

6.3.1. METHODOLOGICAL LIMITATIONS AND DRAWBACKS

The main methodological drawback is that this model was developed to be field-specific for Vega and Gjøa. The model must consequently be modified for other Wintershall-operated field by including relevant compartments and sources. This is cumbersome work with risk of errors, since the data has to be collected from NEMS and inserted in the inventory manually. Additionally, the model must be updated as emission factors or climate change research improves. It should also be mentioned that this was a simple case for a bottom-up LCA, as Gjøa has installed electrical power from shore. Platforms without power from shore could be even more comprehensive with respect of emission sources, and spreadsheet modelling may not be applicable.

LCA was originally developed for products and has less commonly been applied for processes [27]. Processing units on offshore installations may be subjected to ‘lock-in' technology due to high modification expenses. What is more, the oil and gas industry is naturally restricted to the reservoir conditions. Hence, there is less freedom of choice related to processing philosophy and the potential of LCA can be limited as compared with other industries. One can therefore suggest that the potential of emission reduction may be higher for indirect sources related to Vega production (e.g. upstream production of chemicals, products for maintenance, other equipment), rather than the offshore processing itself. However, increased focus on improvement can reduce cost and find new ways of adapting to the natural environment.

Information related to uncertainty of the inventory data is limited, and the accuracy of the result can therefore be questioned. The complex nature of environmental impacts and aspects related to the estimation and quantification methods adds up several layers of uncertainties. Uncertainty analysis therefore had to be excluded from this study.

6.3.2. RECOMMENDATION FOR FURTHER WORK

As stated in the goal of the LCI, non-GHG reported to EEH (NO_x, SO_x, nmVOC and CO) and electrical energy consumption was included in the LCI (chapter 4.1.1.). This was to evaluate the possibility of adding more impact categories, e.g. acidification potential, eutrophication potential or ozone depletion potential. The inventory results showed that emission of non-GHG accounted for only 0,85 % (fig. 35). CO_2 is known to contribute to ocean acidification and could be the more relevant impact category to include. It could also be interesting to include electrical energy consumption as an impact category. This could give more information of how the electricity is produced, which again would lead to better understanding of the environmental impact related to generating electricity onshore.

Future footprint models can focus on developing field specific models or investigate opportunities to develop a generalized model. Reporting practices of indirect sources described in the scope of this LCI should be implemented to yield a more complete footprint. This include waste management, IMR vessels and LWI vessels in transit and mobilization.

The gas turbine was identified at the major emission sources. The gas turbine is already equipped with WHRU, and some energy is therefore recovered. However, this heat is currently used for the MEG regeneration system, which will not be used if the process philosophy of Vega changes (chapter 3). Possible utilization of the heat recovered could therefore be evaluated. However, the potential of this heat can be limited as processing of gas require cooling power rather than heating power. Further improvements are linked with reduced consumption of fuel gas in the gas turbine. It is therefore recommended to perform a detailed study of how the operation conditions of the gas turbine can be optimized, especially as the system is expected to enter low-low pressure mode around 2020 (chapter 2.5.1). Optimization processes can for example be;

- Avoid pressure drops in recompression system.
- Utilize the energy of pressure drops in the systems.

Values for GWP should be updated as new assessment reports are published (AR6 will be published in 2022). It is recommended to follow the guidelines given by the IPCC as this is the most important organization for climate change research worldwide. It can also be of interest to implement TAGWP in the inventory instead of GWP, as correct timing of emission is expected to give better result [10].

7. CONCLUDING REMARKS

Emission resulting from tie-in subsea oil and gas field was considered as the main knowledge gap of this project. This was because most emissions from offshore subsea fields are reported from the host platform. The methodological framework of LCA described by ISO was used to allocate emissions to field level rather than facility level. The carbon footprint of Vega and Gjøa could then be assessed individually, giving Wintershall a better overview of Vega's contribution to GHG emissions. How the LCI approach used in this thesis would change the emission profile compared to the current reporting practice is illustrated fig. 43.

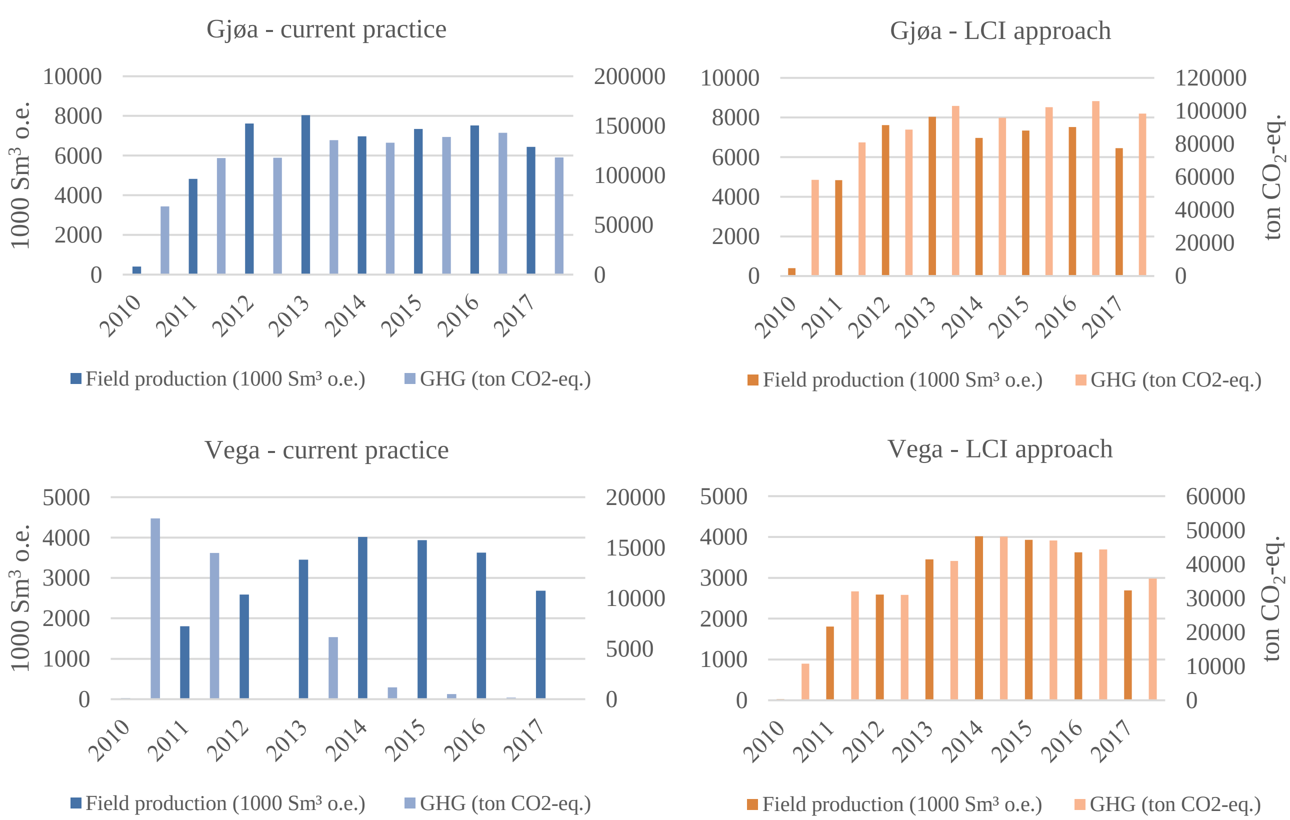

Figure 43 Comparison of emission profiles based on the current reporting practice and the life cycle inventory (LCI) approach. GHG = greenhouse gas, Sm^3 = standard cubic meter, o.e. = oil equivalence, CO_2-eq. = CO_2 equivalence.

Whether or not the inventory result reflects the actual emission due to Vega production cannot be justified based on the current knowledge. This is due to lack of physical evidence that can link emissions to Vega or Gjøa production separately. The degree of uncertainty related to the data used in this analysis is currently not well understood. However, sensitivity analysis proved to be a useful tool to investigate how uncertainties and data errors may affect the carbon footprint and GHG intensity.

The bottom-up approach chosen for the inventory modelling can be argued as cumbersome. However, developing emission inventories based on primary data is educative for Wintershall as an operator. Further implementation of LCA within Wintershall should be based on the intended use and goals set by the company. Complete inventories will give an increased overview of which activities that contributes the most to the total organizational carbon footprint. For this, more comprehensive reporting practices is required within Wintershall and Neptune. On the other hand, field-specific, or even case-specific inventories, have the ability to increase detail level and make it easier to assess operational changes and modifications. Specific inventories also decrease the need for data collection and comprehensiveness of the inventories. The future implementation of LCA in Wintershall is an iterative process, and even more sophisticated LCA methods can be targeted by increased knowledge within the company.

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9. APPENDICES

Appendix 1: Gjøa metering and analyzing systems

Overview of metering and analyzing systems on Gjøa, relevant for Vega gas and condensate production [60].

Measuring unit	Location	Component	Function
Vega condensate metering system	Downstream Vega 2nd stage separator, oil outlet	Ultrasonic flowmeter	Measure total Vega condensate production (fiscal settlement in Gjøa system)
		Ultrasonic flowmeter	
Vega condensate sampling system	Downstream Vega 2nd stage separator, oil outlet. Small oil stream is diverted to sampling unit	Density analyser	Measure density of condensate
		Density analyser	
		Water analyser	Measure water content of condensate
		Water analyser	
Vega gas metering system	Downstream Vega 1st stage separator, gas outlet	Ultrasonic flowmeter	Measure Vega gas production from 1st stage separator
		Ultrasonic flowmeter	
Vega gas metering system	Downstream Vega 2nd stage separator, gas outlet	Ultrasonic flowmeter	Measure Vega gas production from 2nd stage separator
		Ultrasonic flowmeter	
Vega gas analyser system	Downstream Vega 1st and 2nd stage separator, gas outlet. Small gas stream is diverted to GC analyzers	Gas chromatograph	Measure Vega gas composition, CO_2 content and H_2O content from Vega 1st and 2nd stage separator
		Gas chromatograph	
Vega/Gjøa export oil metering system	Downstream Gjøa 3. stage separator	Ultrasonic flowmeter	Measure total oil production of Gjøa
		Ultrasonic flowmeter	
Vega/Gjøa export oil analyser system	Downstream Gjøa 3. stage separator	Density analyser	Measure the density of the oil
		Density analyser	
		H_2O analyser	Measure water content in the oil
		H_2O analyser	
Vega/Gjøa export gas metering system	Downstream gas export compressor	Ultrasonic flowmeter	Measure Vega and Gjøa total export gas
		Ultrasonic flowmeter	
		Pressure sensor	Measure the operating pressure
		Pressure sensor	
		Temperature sensor	Measure the operating temperature
		Temperature sensor	
		Density analyser	Measure density of export gas
		Density analyser	
Fuel gas metering system	Downstream fuel gas filtering unit	Coriolis	Measure flow rate
		Calometric	Measure calometric value
		Water dew point	Measure dew point
Vega/Gjøa export gas analysing system	Downstream gas export compressor	Gas chromatograph	Measure gas composition
		Gas chromatograph	
		H_2S analyser	Measure H_2S and O_2 content in export gas
		O_2 analyser	
HP flare metering	Flare tower	Ultrasonic flowmeter	Measure amount of fluid flared under HP conditions (~14 barg)
	Flare tower	Coriolis meter	Measure amount of nitrogen used to flush HP flare top, to avoid oxygen entering the system
LP flare metering	Flare tower	Ultrasonic flowmeter	Measure amount of fluid flared under LP conditions

		Coriolis meter	Measure amount of nitrogen used to flush HP flare top, to avoid oxygen entering the system
Flare analysator	Flare tower	O_2 analyser	Measure O_2 in atmospheric vent manifold, HP flare manifold and LT flare manifold. Too high oxygen level trig alarm

Appendix 2: Cold venting and fugitive emissions – sources and quantification methods

Potential emission sources of CH_4 and nmVOC identified in the latest NEA survey for cold venting and fugitive emissions. Due to standardization, some facility-specific sources is left out. Blue color means major contributors to waste gas, whereas orange show insignificant sources. Retrieved from NEA [45].

Emission source by component	Sub-source/sub-processes
Triethylene glycol (TEG) regenerator	TEG degasser tank
	TEG regenerator
	Stripping gas for TEG regeneration
Produced water treatment	Produces water degassing tank
	Produced water flotation unit (off-gas from water)
	Flotation gas (where HC gas is used)
	Discharge caisson
Compressor seal oil (wet seals)	Degassing pots
	Seal oil holding tanks
	Seal oil storage tanks
Dry compressor seals (19%)	Primary seal gas (primary vent)
	Secondary seal gas (secondary vent)
	Leakage of primary seal gas to secondary seal vent
Monoethylene glycol (MEG) regeneration	MEG degassing tank
	MEG regenerator
	Stripping gas for MEG regeneration
Purge and blanket gas	
Vent header (measured values)	
Flare gas not burnt	Extinguished flare
	Delayed flare ignition
	Non-combustible flare gas
	Open cold flare purged with N_2
Gas leaks in the process	Large gas leaks (requiring investigation)
	Small gas leaks/fugitives
Reciprocating compressors	Separator chamber
	Chankshaft housing

Liquid ring compressors	
Skrew compressor	
Stripping gas for injection water	
Production riser annulus bleed	
Drilling	Shale shaker
	Mud separator
Direct emissions from gas turbines	Start gas for gas turbines
	Purging turbine at startup
	Depressurizing turbines at shutdown
Amin regeneration	Amin degassing tank
	Amin regenerator
Gas freeing of process systems	
Depressurization/gas freeing of instruments/instrument bridles	
Gas analysers and test/sample stations	
Low pressure scrubbers	
Pig launchers and receivers	
Corrosion coupons	
Flexible riser annulus bleed	
Gas freeing from oil storage tanks on FPSOs	Inspection of storage tanks
	Abnormal operation conditions
Consumption oil tanks (diesel, lubrication oil, etc)	
Double block and bleed (DBB) valves	

Methods used in new protocols described by the NEA [45].

Main source	Sub-source	Method category	General definition
Triethylene glycol (TEG) regeneration	TEG degassing tank	FSM	Dedicated computer programme (GRI-GLYCalc, for example)
	TEG regenerator	GM	Analysis of TEG solution, alternatively the GRI-GLYCalc software
	Stripping gas	GM	Stripping gas flow rate
Produced water treatment	Produced water degassing tank	GM	Based on the pressure reduction and produced water volume
	Flotation tank / CFU	GM	Based on upstream pressure and produced water volume
	Flotation gas	GM	Hydrocarbon flotation gas flowrate
	Discharge caisson	GM	Based on the upstream pressure and produced water discharge volume
Compressor seal oil (wet seals)	Degassing pots	FSM	Established by each operator
	Seal oil holding tank	FSM	Established by each operator
	Seal oil storage tank	FSM	Established by each operator
Reciprocating compressors	Separator chamber	FSM	Simulations, vendor data, etc
	Crank house	FSM	Simulations, vendor data, etc
Dry compressor seals	Primary seal gas	GM	Seal gas metering/supplier data
	Secondary seal gas	GM	Seal gas metering/supplier data
	Leakage of primary sealing gas to secondary vent	GM	Seal gas metering/supplier data
Flare gas not burnt	Extinguished flare and delayed flare ignition	GM	Logging of time with unignited flaring/flare gas metering
	Non-combustible flare gas	FSM	Established by each operator
	Open cold flare purged with inert gas	GM	Flare gas metering
Leakages in the process	Large gas leaks	GM	Emission rate, duration, volume (current practice)
	Small gas leaks/fugitive emissions	GM	OGI "leak/no leak" method
Cold vent		GM	Waste gas metering/determining flow rate
Purge and blanket gas		GM	Purge/blanket gas metering/flow rate determination
Monoethylene glycol (MEG) regeneration	MEG degassing tank	GM	Recognised computer programmes (GRI-GLYCalc, MultiPro Scale, etc)
	MEG regenerator	GM	Recognised computer programmes (GRI-GLYCalc, MultiPro Scale, etc)
	Stripping gas	GM	Stripping gas flow rate
Amine regeneration	Amine degassing tank	FSM	Established by each operator
	Amine regenerator	FSM	Established by each operator
Gas analysers and test/sample stations		GM	Slipstream flowrate
Drilling		GM	Emission factor per completed wellbore
Gas freeing of FPSO oil storage tanks		GM	Storage tank volume
Gas freeing of process plants		GM	Volume of process plant

Appendix 3: Gjøa significant electricity consumers

List of significant energy-consuming equipment on Gjøa, where energy demand and average use efficiency is estimated. The numbers are derived from operating parameters from the 4th quarter of 2014. Retrieved from Neptune [61].

Equipment name	**Energy source**	**Max cap. (MW)**	**Consumption (MWh)**	**Average use eff (%)**
Low-pressure compressor	Electricity	17,3	10815,13	97,8
3rd stage re-compressor	Electricity	11,1	22656,13	97,6
1st and 2nd stage re-compressor	Electricity	4,5	6140,13	96,9
Gas recovery compressor A	Electricity	0,5	251,00	95,0
Gas recovery compressor B	Electricity	0,5	102,59	95,0
Crude oil export pump A	Electricity	2,5x2	1493,86	96,0
Crude oil export pump B	Electricity	2,5	2782,08	96,0
Sea water lift pump A	Electricity	1,4x3	2004,32	84,7
Sea water lift pump B	Electricity	1,4	1846,67	86,1
Sea water lift pump C	Electricity	1,4	2072,77	85,9
Cooling medium pump A	Electricity	0,5x3	713,32	95,9
Cooling medium pump B	Electricity	0,5	672,59	95,9
Cooling medium pump C	Electricity	0,5	505,49	95,9
Gas Turbine	Fuel gas	30	143546,00	37,4
Export compressor	Fuel gas		NA	NA
WHRU	Exhaust from GT	30,2	21096,22	33,6
Fire pumps (4 units)	Diesel	2,8x4	51,78	100,0
Emergency generator	Diesel	5,35	18,43	64,7
Essential generator	Diesel	1,73	66,46	76,1

Categorized electrical energy consumers.

Electricity consumer	El. consumption (MWh)	% of significant el. consumption (MWh)	% of total el. consumption (MWh)
Gas recompression	39964,99	76,77	63,03
Low-pressure compressor	10815,13	20,78	17,06
3rd stage re-compressor	22656,13	43,52	35,73
1st and 2nd stage re-compression	6140,13	11,80	9,68
Gas recovery compressor A	251,00	0,48	0,40
Gas recovery compressor B	102,59	0,20	0,16
Oil export	4275,94	8,21	6,74
Crude oil export pump A	1493,86	2,87	2,36
Crude oil export pump B	2782,08	5,34	4,39
Gjøa gas lift	5923,75	11,38	9,34
Sea water lift pump A	2004,32	3,85	3,16
Sea water lift pump B	1846,67	3,55	2,91
Sea water lift pump C	2072,77	3,98	3,27
Cooling medium system	1891,40	3,63	2,98
Cooling medium pump A	713,32	1,37	1,13
Cooling medium pump B	672,59	1,29	1,06
Cooling medium pump C	505,49	0,97	0,80
Unsignificant energy consumers	11348,92		17,90

Appendix 4: Vessel activity related to Gjøa and Vega

List of vessels related to Vega production (operational phase only). Vessel names was found in NEMS accounter.

Vessel name	**Operator**	**Purpose**
Edda fauna	Deep ocean	Subsea IMR and ROV support vessel
Island wellserver	Island offshore	RLWI
Island frontier	Island offshore	RLWI
Ocean Alden	Atlantic offshore	Fast supply vessel
Misc vessels Gjøa	Misc	-
Torsborg	Skanski offshore	Supply vessel
Normand Naley	Solstad farstad	Supply vessel
Siddis sailor	O.H. Meling & Co. AS	

Appendix 5: Vega life cycle inventory excel sheet

Allocation keys

Tab. 1.1.. Energy conversion factors used in model

Field	Net calorific value (GJ/Sm3)
Vega/Gjøa gas	0.0414
Vega condensate	33.975 (2010-2012)
	38.5 (fom. 2013)
Gjøa oil	36.7625 (2010-2012)
	33.7408 (2013)
	33.4556 (2014)
	33.37138 (fom. 2015)

Production	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Vega																					
Gas (Sm3)	21779576	896813304	1259488679	1773528266	2001667942	2007597076	1977603798	1522103787	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil/condensate (m3)	17984	658304.995	852772.037	999977.375	1151776.74	1057986.53	853723.126	563857.141	0	0	0	0	0	0	0	0	0	0	0	0	0
Prod. Water (m3)	0	12573.89	12630.8	18205.8	22255.8	26530.9227	27963.4702	20891.6268	0	0	0	0	0	0	0	0	0	0	0	0	0
Total (GJ)	1512680.846	59493983	81115761.3	111923199	127212457	123847001	114741138	84723596.7	0	0	0	0	0	0	0	0	0	0	0	0	0
Gjøa																					
Gas (Sm3)	94460348	2123548504	3552651119	4561979052	4120710241	4527941186	4839774988	4287212038	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil/condensate (m3)	125917	2161477.91	2828828.3	1978338.3	1474726.93	1346049.42	1216054.74	835406.829	0	0	0	0	0	0	0	0	0	0	0	0	0
Prod. Water (m3)	375	101156	107167.9	175618.1	266785	474983.17	740002.8	812787.383	0	0	0	0	0	0	0	0	0	0	0	0	0
Total (GJ)	8539682.12	167376240	251074557	255616650	219935278	232376292	240948109	205369257	0	0	0	0	0	0	0	0	0	0	0	0	0
Total																					
Gas (Sm3)	116239924	3020361809	4812139797	6335507318	6122378183	6535538262	6817378785	5809315826	1	1	1	1	1	1	1	1	1	1	1	1	1
Oil/condensate (Sm3)	143901	2819782.91	3681600.33	2978315.67	2626503.67	2404035.96	2069777.87	1399263.97	1	1	1	1	1	1	1	1	1	1	1	1	1
Prod. Water (m3)	375	113729.89	119798.7	193823.9	289040.8	501514.093	767966.271	833679.01	1	1	1	1	1	1	1	1	1	1	1	1	1
Total (GJ)	10052362.97	226870223	332190318	367539849	347147735	356223292	355689247	290092854	1	1	1	1	1	1	1	1	1	1	1	1	1

Ak Vega	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Vega tot. Prod.	0.150480126	0.26223795	0.2441846	0.3045199	0.36645049	0.34766677	0.32258815	0.29205682	0	0	0	0	0	0	0	0	0	0	0	0	0
2. Vega gas	0.187367432	0.29692248	0.26173152	0.27993469	0.32694288	0.3071816	0.29008272	0.26201085	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Vega oil/condensate	0.124974809	0.23345946	0.2316308	0.33575265	0.43852089	0.44008765	0.41247089	0.40296695	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Prod. water	0	0.11055924	0.10543353	0.09392959	0.07699882	0.05290165	0.03641237	0.02505956	0	0	0	0	0	0	0	0	0	0	0	0	0

Ak Gjøa	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Gjøa tot. Prod.	0.849519874	0.73776205	0.7558154	0.6954801	0.63354951	0.65233323	0.67741185	0.70794318	0	0	0	0	0	0	0	0	0	0	0	0	0
2. Gjøa gas	0.812632568	0.70307752	0.73826848	0.72006531	0.67305712	0.6928184	0.70991728	0.73798915	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Gjøa oil/condensate	0.875025191	0.76654054	0.7683692	0.66424735	0.56147911	0.55991235	0.58752911	0.59703305	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Prod. water	1	0.88944076	0.89456647	0.90607041	0.92300118	0.94709835	0.96358763	0.97494044	0	0	0	0	0	0	0	0	0	0	0	0	0

Vega Inventory

Emission from processing

COMBUSTION

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	SUM VEGA	GWP(100), VEGA	GWP(AR5)
Flaring (HP and LP)																							Ak = 1		28 =GWP_CH4
Gas flared (kg/yr)	10229561.3	7925748.93	1702577.47	1141270.555	1579551.608	346079.2057	683109.0917	641685.233														24249583.38	5487979.8		265 =GWP_N2O
CO2 (kg/yr)	38375257.39	27404488.5	5384581.43	3073864.559	3518703.5	864154.685	1759795.546	1776255.62														82157101.25	17888421	17888420.63	
NOx (kg/yr)	16848.6892	13054.1747	2797.14554	1593.301641	1814.498013	428.4702593	944.967318	858.885347														38340.13202	8496.472		
CH4 (kg/yr)	2888.34672	2237.85852	479.510664	273.1374242	311.0568022	73.45204446	161.9943974	147.237488														6572.59406	1456.5381	40783.06567	
nmVOC (kg/yr)	722.08668	559.46463	119.877666	68.28435606	77.76420054	18.36301111	40.49859934	36.809372														1643.148515	364.13451		
SOx (kg/yr)	50	50.3518167	10.7889899	6.145592045	6.998778049	1.652671	3.644873941	3.31284348														132.8955652	30.51674		
CO (kg/yr)	15344.34195	11888.6234	2553.8662	1711.905832	2369.327412	519.1188085	1024.663638	962.52785														36374.37508	8231.9697		
N2O(kg/yr)	204.591226	158.514979	34.0515493	22.82541109	31.59103215	6.921584114	13.66218183	12.8337047														484.9916677	109.7596	29086.29296	
	2.733996																								
Gas turbine (Gas Compression)																							Ak = 2		
Fuel consumption (kg/yr)	3249495.782	23071578.9	33732866.6	43642093.54	42911557.8	45725818.04	46921561.93	40911330.4														280166303	80911315		
CO2 (kg/yr)	8884108.47	64086025.7	92574876.8	118991030.1	116819371.2	124508470.4	127587855.4	111481496														764933233.7	220893021	220893020.6	
NOx (kg/yr)	2405.7882	48857.4612	63995.0396	71467.01859	61691.29	63788.2	74055.36	46476.606														432736.7636	125136.91		
CH4 (kg/yr)	1216.25959	24700.1609	36114.0101	46689.98717	45832.44498	48925.45341	50300.49813	43964.424														297743.2383	86208.294	2413832.237	
nmVOC (kg/yr)	320.77176	6514.32816	9524.5741	12313.84277	12087.6778	12903.41628	13266.06544	11595.0129														78525.68923	22736.253		
SOx (kg/yr)	19.7471574	146.572384	214.302917	277.0614623	271.9727504	290.3268664	298.4864724	260.887791														1779.3578	513.91338		
CO (kg/yr)	5524.142829	39221.6841	57345.8732	74191.55901	72949.64825	77733.89066	79766.65528	69549.2617														476282.7151	137549.24		
N2O(kg/yr)	61.74041986	438.359999	640.924465	829.1997772	815.3195981	868.7905427	891.5096766	777.315278														5323.159757	1537.315	407388.4726	
Engines (Fire pumps and Emergency/Essential generators)																							Ak = 1		
Fuel consumption (kg/yr)	527126.7414	150678	164365.2	126673.2945	113915.5659	120976.515	87838.425	123936.811														1415510.553	345881.73		
CO2 (kg/yr)	1670991.77	477649.26	521037.684	401281.996	360867.4254	383235.453	278258.9546	392613.227														4485935.771	1096043.2	1096043.241	
NOx (kg/yr)	36870.69569	9040.68	9861.912	7600.39767	6834.933954	5322.96666	3864.8907	5453.21969														84849.69636	19836.417		
nmVOC (kg/yr)	2642.162	753.39	821.826	633.3664725	569.5778295	604.882575	439.192125	619.684056														7084.081057	1730.3911		
SOx (kg/yr)	527.7564736	150.678	164.3652	126.6732945	113.9155659	120.976515	87.838425	123.936811														1416.140285	345.9765		
CO (kg/yr)	3689.88719	1054.746	1150.5564	886.7130615	797.4089613	846.835605	614.868975	867.557678														9908.573871	2421.1721		
N2O(kg/yr)	105.4253483	30.1356	32.87304	25.3346589	22.78311318	24.195303	17.567685	24.7873622														283.1021106	69.176347	18331.73194	

Energy consumption	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	SUM VEGA
Total	100 %																						
MWh/yr	9415.4	154413.8	229022.9	256392.7	242566.6894	254351.331	253152.9997	265551.694														1664867.514	
Gas compression	63.03 %																						Ak = 2
MWh/yr	5934.52662	97327.0181	144353.134	161604.3188	152889.7843	160317.644	159562.3357	167377.232														1049365.994	302404.72
Crude oil export	6.74 %																						Ak = 3
MWh/yr	634.59796	10407.4901	15436.1435	17280.86798	16348.99486	17143.27971	17062.51218	17898.1841														112212.0704	40850.707
Cooling medium pump	2.98 %																						Ak = 1
MWh/yr	280.57892	4601.53124	6824.88242	7640.50246	7228.487343	7579.669665	7543.95939	7913.44047														49613.0519	15270.982
Non-significant consumers	17.9 %																						Ak = 1
MWh/yr	1685.3566	27640.0702	40995.0991	45894.2933	43419.43739	45528.88826	45314.38694	47533.7531														298011.2849	91728.383

COLD VENTING

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	SUM VEGA	GWP(100), VEGA
Gas freeing from process plants																							Ak = 2	
CH4 (kg/yr)	1100	1100	1100	1100	1100	1100	1100	1100														8800	2433.3916	68134.96432
nmVOC (kg/yr)	1100	1100	1100	1100	1100	1100	1100	1100														8800	2433.3916	
Gas analysers and test/sample stations																							Ak = 2	
CH4 (kg/yr)	2400	2400	2400	2400	2400	2400	2400	2400														19200	5309.218	148658.104
nmVOC (kg/yr)	1500	1500	1500	1500	1500	1500	1500	1500														12000	3318.2612	
Leakages in the process																							Ak = 2	
CH4 (kg/yr)	27700	27700	27700	27700	27700	27700	27700	27700														221600	61277.224	1715762.283
nmVOC (kg/yr)	15200	15200	15200	15200	15200	15200	15200	15200														121600	33625.047	
Produced water treatment																							Ak = 4	
CH4 (kg/yr)	33900	33900	33900	33900	33900	33900	33900	33900														271200	16993.892	475828.9811
nmVOC (kg/yr)	8500	8500	8500	8500	8500	8500	8500	8500														68000	4261.0054	
Flare not burnt																							Ak = 1	
CH4 (kg/yr)	58200	58200	58200	58200	58200	58200	58200	58200														465600	133288.76	3732085.179
nmVOC (kg/yr)	35600	35600	35600	35600	35600	35600	35600	35600														284800	81530.58	
MEG regenerator																								
CH4 (kg/yr)	600	600	600	600	600	600	600	600														4800	4800	134400
nmVOC (kg/yr)	7000	7000	7000	7000	7000	7000	7000	7000														56000	56000	

FUGITIVE SOURCES

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	SUM VEGA	GWP(100), VEGA
From processing																							Ak = 1	
CH4 (kg/yr)	366306.4094	366306.409	366306.409	366306.4094	366306.4094	366306.4094	366306.4094	366306.409														2930451.275	838909.38	23489462.57
nmVOC (kg/yr)	239430.9517	239430.952	239430.952	239430.9517	239430.9517	239430.9517	239430.9517	239430.952														1915447.614	548341.13	

Indirect emissions from marine activity

VEGA INTERVENTIONS

Under well-control

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	VEGA SUM	GWP(100), VEGA
Engine																								
Fuel consumption (kg/yr)					20762.40868	160440	47880															229082.4087	229082.41	
CO2 (kg/yr)					65816.83553	508594.8	151779.6															726191.2355	726191.24	726191.2355
NOx (kg/yr)					1454.355	11230.8	3351.6															16036.755	16036.755	
nmVOC (kg/yr)					103.8825	802.2	239.4															1145.4825	1145.4825	
SOx (kg/yr)					20.7557235	160.27956	47.88															228.9152835	228.91528	
CO (kg/yr)					145.3368608	1123.08	335.16															1603.576861	1603.5769	
N2O(kg/yr)					4.152481737	32.088	9.576															45.81648174	45.816482	12141.36766

Outside well-control

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	VEGA SUM	
Engine																								
Fuel consumption (kg/yr)					13133.47172	25990.1	13136.7															52260.27172	52260.272	
CO2 (kg/yr)					41633.10534	82388.617	41643.339															165665.0613	165665.06	165665.0613
NOx (kg/yr)					696.0740009	1377.4753	696.2451															2769.794401	2769.7944	
nmVOC (kg/yr)					65.66735858	129.9505	65.6835															261.3013586	261.30136	
SOx (kg/yr)					36.7737208	72.77228	36.78276															146.3287608	146.32876	
CO (kg/yr)					91.93430201	181.9307	91.9569															365.821902	365.8219	
N2O(kg/yr)					2.626694343	5.19802	2.62734															10.45205434	10.452054	2769.794401

VEGA IMR OPERATIONS

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	VEGA SUM	
Engine																								
Fuel consumption (kg/yr)	0	0	0	0	0	0	0	0														0	0	
CO2 (kg/yr)	0	0	0	0	0	0	0	0														0	0	0
NOx (kg/yr)	0	0	0	0	0	0	0	0														0	0	
nmVOC (kg/yr)	0	0	0	0	0	0	0	0														0	0	
SOx (kg/yr)	0	0	0	0	0	0	0	0														0	0	
CO (kg/yr)	0	0	0	0	0	0	0	0														0	0	
N2O(kg/yr)	0	0	0	0	0	0	0	0														0	0	0

SUPPLY SHIP

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	VEGA SUM	
Engine																						Ak=1		
Fuel consumption (kg/yr)	2132439.023	2132439.02	2132439.02	2132439.023	2584049.4	2371624.65	1701227.79	1872854.25														17059512.18	4917412.1	
Vega allocation fuel (kg/yr)	320889.6929	559206.446	520708.779	649370.1248	946926.1642	824535.0754	548795.9324	546979.859															1490277.1	
CO2 (kg/yr)	6759831.701	6759831.7	6759831.7	6759831.701	8191436.598	7518050.141	5392892.094	5936947.97														54078653.61	15588196	15588196.27
NOx (kg/yr)	113019.2682	113019.268	113019.268	113019.2682	136954.6182	125696.1065	90165.07287	99261.2753														904154.1455	260622.84	
nmVOC (kg/yr)	10662.19511	10662.1951	10662.1951	10662.19511	12920.247	11858.12325	8506.13895	9364.27125														85297.5609	24587.06	
SOx (kg/yr)	5970.829263	5970.82926	5970.82926	5970.829263	7235.33832	6640.54902	4763.437812	5243.9919														47766.6341	13768.754	
CO (kg/yr)	14927.07316	14927.0732	14927.0732	14927.07316	18088.3458	16601.37255	11908.59453	13109.9798														119416.5853	34421.885	
N2O(kg/yr)	426.4878045	426.487805	426.487805	426.4878045	516.80988	474.32493	340.245558	374.57085														3411.902436	983.48241	260622.8399

Indirect emission from other sources

HELICOPTER

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM	VEGA SUM	
Engine																							Ak = 1	
Fuel consumption (GJ/yr)	3898.023478	3898.02348	3898.02348	3898.023478	4372.82256	4114.849062	3308.763898	3795.65839														31184.18782	8956.583	
CO2 (kg/yr)	268573.8176	268573.818	268573.818	268573.8176	301287.4744	283513.1003	227973.8326	261520.863														2148590.541	617108.57	617108.5696

Vega yearly outputs

Emission to air	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	SUM VEGA	FORMULA CHECK
CO2 (kg)	8748392.556	28183450.8	27388053.2	36508257.57	42834544.89	41983714.49	39675132.38	31653099.7	0	0	0	0	0	0	0	0	0	0	0	0	0	256974646	256974646
Flaring	5774713.57	7186496.99	1314831.89	936052.9381	1289430.615	300437.8658	567689.1966	518767.57	0	0	0	0	0	0	0	0	0	0	0	0	0		
Gas turbine	1664592.585	19028581.4	24229763.5	33309716.91	38193261.4	38246710.7	37011032.44	29209361.6	0	0	0	0	0	0	0	0	0	0	0	0	0		
Fire pump engine	251451.0523	125257.765	127229.381	122198.3546	132240.0442	133238.2311	89763.04252	114665.371	0	0	0	0	0	0	0	0	0	0	0	0	0		
Marine (well control)	0	0	0	0	65816.83553	508594.8	151779.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Marine	1017220.327	1772684.43	1650646.83	2058503.296	3043389.046	2696164.806	1781326.445	1733926.15	0	0	0	0	0	0	0	0	0	0	0	0	0		
Helicopter	40415.02194	70430.2484	65581.5913	81786.07296	110406.9421	98568.08309	73541.65783	76378.952	0	0	0	0	0	0	0	0	0	0	0	0	0		
CH4 (kg)	70988.16808	132854.516	125567.414	154942.149	184070.0371	174618.7385	162469.2621	145166.408	0	0	0	0	0	0	0	0	0	0	0	0	0	1150677	1150677
Flaring	434.6387785	586.851439	117.089122	83.175782	113.986917	25.53683485	52.25747361	43.0017127	0	0	0	0	0	0	0	0	0	0	0	0	0		
Gas turbine	227.8874354	7334.03293	9452.17488	13070.147	14984.59145	15028.99888	14591.30544	11519.1562	0	0	0	0	0	0	0	0	0	0	0	0	0		
Fugitive/cold venting	70325.64186	124933.632	115998.15	141788.8262	168971.4587	159564.2028	147825.6992	133604.25	0	0	0	0	0	0	0	0	0	0	0	0	0		
N2O (kg)	122.3974157	291.471567	288.233847	376.6615059	482.6527767	479.8878084	390.6484656	324.048499	0	0	0	0	0	0	0	0	0	0	0	0	0	2756	2756
Flaring	30.78691348	41.5686436	8.31486409	6.950791977	11.57654916	2.406404774	4.407258018	3.74817099	0	0	0	0	0	0	0	0	0	0	0	0	0		
Gas turbine	11.56814389	130.158936	167.750137	232.1217811	266.5629357	266.8764657	258.6115541	203.665038	0	0	0	0	0	0	0	0	0	0	0	0	0		
Fire pump engine	15.8644197	7.90269808	8.02709026	7.714907877	8.348882948	8.411902779	5.667127075	7.23931822	0	0	0	0	0	0	0	0	0	0	0	0	0		
Marine (w. well control)	0	0	0	0	4.152481737	32.088	9.576	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Marine	64.17793859	111.841289	104.141756	129.874025	192.0119272	170.1050351	112.3865265	109.395972	0	0	0	0	0	0	0	0	0	0	0	0	0		
GHG emission (kg)	10768496.58	31980617.2	30980322.7	40946453.04	48116408.91	47000209.43	44327793.57	35803632	0	0	0	0	0	0	0	0	0	0	0	0	0	289923933	289923933
GHG intensity (kg GHG/GJ	7.118815977	0.53754372	0.38192729	0.365844198	0.378236613	0.379502202	0.386328692	0.42259339	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**0.411490709**	**kg CO2-eq./GJ**
Future GHG emission																						**17.406057**	**tonne CO2-eq./ktoe**
Flaring	5795041.988	7213944.52	1320313.82	940223.8199	1295690.035	301790.5945	570320.3293	520964.884	0	0	0	0	0	0	0	0	0	0	0	0	0	17958290	17958290
Gas turbine	1674038.992	19268426.4	24538878.2	33737193.29	38683469.14	38738244.93	37488121.06	29585869.3	0	0	0	0	0	0	0	0	0	0	0	0	0	223714241	223714241
Fire pump engine	255655.1235	127351.98	129356.56	124242.8052	134452.4982	135467.3853	91264.8312	116583.79	0	0	0	0	0	0	0	0	0	0	0	0	0	1114375	1114375
Fugitive/cold venting	1969117.972	3498141.68	3247948.19	3970087.133	4731200.843	4467797.678	4139119.577	3740919	0	0	0	0	0	0	0	0	0	0	0	0	0	29764332	29764332
Marine (well control)	0	0	0	0	66917.24319	517098.12	154317.24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	738333	738333
Marine	1034227.48	1802322.37	1678244.39	2092919.912	3094272.207	2741242.64	1811108.874	1762916.08	0	0	0	0	0	0	0	0	0	0	0	0	0	16017254	16017254
Helicopter	40415.02194	70430.2484	65581.5913	81786.07296	110406.9421	98568.08309	73541.65783	76378.952	0	0	0	0	0	0	0	0	0	0	0	0	0	617109	617109
NOx (kg)	584884.7096	402610.236	19840.6662	74706.57477	60502.9802	32824.94458	26385.38366	14020.8685	0	0	0	0	0	0	0	0	0	0	0	0	0	1215776	1215776
Gjøa process	8534.466166	20300.9878	19840.6662	22805.762	23339.11645	21594.14458	23033.78366	14020.8685	0	0	0	0	0	0	0	0	0	0	0	0	0		
Drilling and intervention	576350.2434	382309.248	0	51900.81277	37163.86375	11230.8	3351.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
nmVOC (kg)	53892.63578	90423.0906	85039.7049	103441.2268	123352.6794	117771.818	108246.7667	98166.1168	0	0	0	0	0	0	0	0	0	0	0	0	0	780334	780334
Direct (Gjøa process	52288.18732	87627.0583	82436.161	100194.3762	118448.4987	112716.9921	105197.7035	95431.2175	0	0	0	0	0	0	0	0	0	0	0	0	0		
Intervention (well control)	1604.448465	2796.03223	2603.54389	3246.850624	4904.18068	5054.825877	3049.063162	2734.89929	0	0	0	0	0	0	0	0	0	0	0	0	0		
SOx (kg)	31017.07696	5151.78048	98.8597855	2056.282191	2049.976481	292.0967229	163.9771971	105.519562	0	0	0	0	0	0	0	0	0	0	0	0	0	40936	40936
Direct (Gjøa process	90.64084115	96.2382827	98.8597855	118.0051086	133.2286741	131.8171629	116.0971971	105.519562	0	0	0	0	0	0	0	0	0	0	0	0	0		
Indirect	30926.43612	5055.5422	0	1938.277083	1916.747807	160.27956	47.88	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
CO (kg)	6145.545504	18954.4874	19558.7472	26105.71299	31876.57433	31430.0738	27936.51075	22586.0093	0	0	0	0	0	0	0	0	0	0	0	0	0	159494	184594
Direct (Gjøa process	3899.317654	15040.0422	15913.7857	21560.12212	25010.82002	24353.31757	23667.82232	18757.1503	0	0	0	0	0	0	0	0	0	0	0	0	0		
Indirect	2246.227851	3914.44512	3644.96145	4545.590873	6865.754312	7076.756228	4268.688427	3828.85901	0	0	0	0	0	0	0	0	0	0	0	0	0		
Vega energy consumption (	1487.079994	39783.2777	53034.1551	67343.16263	75715.55864	75255.25611	70375.54274	67260.7591	0	0	0	0	0	0	0	0	0	0	0	0	0	450255	450255
Vega el. energy intensity (k	0.98307584	0.66869414	0.65380827	0.60169083	0.595189813	0.607646982	0.61334186	0.7938846	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**0.639049221**	**kWh/GJ**