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CO_2 Emissions and Energy Consumption for a Subsea Compression System compared with a Topside Compression System

Jens Kristian Berg
Industrial Economics and Technology Management

Abstract

Increasing the recovery rates of oil and gas fields is a common goal between energy companies and policy makers. Through pressure from the public and policy intervention due to changes in the global climate, there is a push to reduce emissions related to the production of hydrocarbons. The installation of gas compressors is often evaluated for gas fields to better the recovery rate and extend the lifetime when the production rates decline. Through development in technology, offshore compression can in some cases be performed both topside and subsea. This thesis analyses the differences in energy consumption and CO_2 emissions for a subsea compression system and a topside compression system targeting increased recovery from a gas and condensate reservoir. Two notional generic gas fields were generated and a realistic production system for both reservoirs was defined. The reservoirs were assigned case numbers 1 and 2, where the difference was the condensate to gas ratio which was specified to be 15 and 1 respectively. Integrated Production Modeling was used to perform predictions of the accumulated production volumes, energy consumption and the associated CO_2 emissions. The results show that the total energy consumption and CO_2 emissions are significantly lower for the subsea system. The average emissions of CO_2 per barrel of oil equivalent produced is approximately 53% lower for the subsea system in both cases. This is because of a lower system pressure drop and accelerated production, causing the total energy consumption of the subsea system to be approximately 37% and 38% lower over the lifecycle for Case 1 and Case 2 respectively. In addition to CO_2 emissions from the compression work, emissions from production of construction materials and emissions from the support systems for the topside facility were included in the analysis. The results show that the impact of including the emissions from production of the construction materials is dwarfed by the emissions from direct power usage. The additional emissions from the energy consumption of the topside support systems are a significant contribution to overall emissions over the lifecycle. These make up approximately 23% of the total topside emissions in Case 1 and Case 2. This constitutes approximately 44% and 46% of the difference in total emissions between the two systems in Case 1 and Case 2 respectively. The accumulated production volume was higher for the subsea system in both cases, representing significant additional revenue. The additional production volume is a result of a lower system pressure drop for the subsea system, allowing a further drawdown of the reservoir pressure when compared with the topside system.

Sammendrag

Å øke utvinningsgraden for olje- og gassfelt er et felles mål mellom energiselskaper og statlige beslutningstakere. Gjennom press både fra det offentlige og fra politiske tiltak som følge av endringer i det globale klimaet, er det et økt fokus på reduksjon av utslipp knyttet til produksjon av hydrokarboner. Installasjon av gasskompressorer blir ofte vurdert for å bedre utvinningsgraden for gassfelt og for å forlenge levetiden når produksjonsratene faller. Etter utvikling av ny teknologi kan offshore gasskompresjon i noen tilfeller nå utføres under vann som et alternativ til konvensjonell kompresjon på en overflatestruktur. Denne oppgaven analyserer forskjellene i energiforbruk og CO_2-utslipp for et undervanns kompresjonssystem og et kompresjonssystem montert på en overflatestruktur med et mål om økt utvinning fra et gass- og kondensatreservoar. To generiske gassfelt ble generert, og et realistisk produksjonssystem for disse reservoarene ble deretter definert. Forskjellen mellom reservoarene var mengden kondensat i forhold til gass, som ble spesifisert til henholdsvis 15 og 1. De to reservoarene ble navngitt tilfelle 1 og tilfelle 2. Integrert produksjonsmodellering ble brukt til estimering av akkumulerte produksjonsvolumer, energiforbruk og tilhørende CO_2-utslipp. Resultatene viser at det totale energiforbruket og CO_2-utslippene er betydelig lavere for havbunnssystemet. De gjennomsnittlige utslippene av CO_2 per fat oljeekvivalenter produsert er i begge tilfeller ca. 53% lavere fra undervannssystemet. Dette skyldes et lavere systemtrykkfall og akselerert produksjon, som resulterer i at det totale energiforbruket til undervannssystemet er omtrent 37% og 38% lavere i løpet av livssyklusen for henholdsvis tilfelle 1 og tilfelle 2. I tillegg til CO_2-utslipp fra kompresjonsarbeidet ble utslipp fra produksjon av stålmaterialer til systemene og utslipp fra støttesystemene til overflateanlegget tatt med i analysen. Resultatene viser at virkningen av å inkludere utslippene fra produksjonen av stålmaterialene blir forsvinnende liten sammenlignet med utslippene fra det direkte strømforbruket. De ytterligere utslippene fra energiforbruket til overflateanleggets støttesystemer er et betydelig bidrag til de totale utslippene over livssyklusen. De utgjør ca. 23% av de totale utslippene fra overflateanlegget i tilfelle 1 og 2. Dette utgjør omtrent 44% og 46% av forskjellen i totale utslipp mellom de to systemene i henholdsvis tilfelle 1 og tilfelle 2. Det akkumulerte produksjonsvolumet var høyere for havbunnssystemet i begge tilfeller, noe som representer en betydelig tilleggsinntekt. Det ekstra produksjonsvolumet er et resultat av et lavere systemtrykkfall for undervannssystemet, noe som tillater ytterligere reduksjon i reservoartrykket i forhold til overflateanlegget.

Acknowledgments

Firstly, I want to express my gratitude to my dear colleagues Emil Gyllenhammar and Geir Inge Olsen for supporting me throughout the work with this thesis. Their guidance and advice have been indispensable in navigating the complex waters of process simulations that formed a key part of the analysis work for this thesis. A special thanks also goes out to my manager Rune Vesterkjær, who motivated me to write my thesis, and to Aker Solutions who made the required utilities available for my work. It has been a great challenge to write this thesis, but one that I have enjoyed for more time than I have not.

I would also like to thank my supervisor at NMBU, Odd Ivar Lekang, and Ola Sørby Omberg also representing NMBU, for always being available for support when required.

Lastly, I want to thank my lovely partner, Nashia Søraune, for supporting me throughout the demanding process it was to write this thesis in parallel with my day-time job. There have been many late nights in the office and your humor has lifted my spirits on many occasions when it has been most needed.

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Abbreviations

BAT	Best Available Techniques
BOE	Barrel of Oil Equivalent
BSCF	Billion Standard Cubic Feet
CGR	Condensate to Gas Ratio
DGC	Dry Gas Compression
EOR	Enhanced Oil Recovery
ETS	Emission Trading System
FBHP	Flowing Bottomhole Pressure
GAP	General Allocation Package
IEA	International Energy Agency
IOGP	International Association of Oil and Gas Producers
IPM	Integrated Production Modeling
IPR	Inflow Performance Relationship
MBOE	Thousand Barrel of Oil Equivalent
MMSCFD	Million Standard Cubic Feet per Day
MSR	Market Stability Reserve
NDC	Nationally Determined Contributions
PFD	Process Flow Diagram
QTY	Quantity
RP	Recommended Practice
TRL	Technology Readiness Level
VLP	Vertical Lift Performance Relationship
WLP	Wet Gas Compression
XT	Subsea Tree

Introduction

As the population of the world grows, the global energy demand is growing with it. As people, countries and regions are getting richer, the demand for products and activities that require energy will tend to increase. On the other side, the world is facing changes in the global climate, and there is a constant focus related to man-made global warming and how to limit this.

An energy transition from fossil fuels to renewables is a hot topic, and energy companies are trying their best to predict the role of different energy sources in the future energy mix. It is believed that natural gas will play an increasingly important role in the world's energy mix. As more and more countries decide to move away from the worse alternatives such as coal, natural gas still secures the flexibility provided by fossil fuels.

There is a strong push from governments to reduce CO_2 emissions related to production of the fossil fuels. In addition to the push from policy makers, there is also an increasing pressure from the public and investors for companies to set climate targets consistent with the goals in the Paris Agreement. To deliver on these expectations, the energy companies have high ambitions to reduce their environmental footprints. This challenge passes on through the supply chain of the energy companies, as new and improved technology is required to deliver energy with lowest possible emissions.

Both the Pollution Control Act and the Industrial Emissions Directive are calling out for Best Available Techniques assessments to obtain permits for developments on the Norwegian continental shelf and in the European Union. An important factor in these assessments is to consider the environmental impact of a possible development. The installation of gas compressors is often evaluated for gas fields to better the recovery rate and extend the lifetime when the production rates decline. With the successful installation of subsea compression systems on both the Åsgard and the Gullfaks gas fields on the Norwegian continental shelf in 2015, technology is now field proven and qualified to challenge conventional topside or onshore compression systems.

Scope of Work and Limitations

The aim of this study is to compare the CO_2 emissions from a subsea compression system with that of a topside compression system over an operational lifecycle, attempting to conclude on which has the lower CO_2 footprint. An analysis will be performed to determine the energy consumption over the lifecycle and the emissions related to supply of that energy. The main goal will be to find the average CO_2 emissions per barrel of oil equivalent produced for the two systems. Two sets of cases will be created as basis for performing the analysis.

Intermediate outcome objectives:

- Present the current market outlook for natural gas in the world and Europe and part of the policy mechanisms that is expected to impact the demand.
- Present a technical review of different methods of improved recovery.
- Provide an overview of the historical development of subsea compression technology and present existing solutions.
- Define a complete production system model for both a topside and a subsea system that can be used to predict the accumulated production volumes of hydrocarbons and the accumulated energy consumption related to the compression work over the field lifecycles.
- Identify the energy consumption related to production of the materials for the systems and the required power for operation of the support systems on a topside facility.
- Identify correlations between CO_2 emissions, power generation and material fabrication, which can be used to determine the total CO_2 emissions associated with the energy consumption of the systems over the lifecycles.

Limitations:

- The main target in the study has not been to optimize the recovery rate or finding the optimized production based on economical perspectives for the given cases, but to establish a realistic and sound comparison foundation for the two systems.
- The analysis is based on a dry gas compression system.
- Only CO_2 emissions related to normal operation have been considered. E.g. excessive flaring or release of pure methane have not been included, as this would be the result

of an upset condition / failure and would have a probabilistic emission rate and volume.

- Operational limitations such as erosion, emulsions, flow induced vibrations, hydrates or wax have not been included in the study as these are highly case specific phenomenon. Hence continuous injection of chemicals into the production has not been considered either.

1. Background

1.1. World energy demand

The International Energy Agency (IEA) published their report “World Energy Outlook 2018” (International Energy Agency, 2018) on the 13th of November 2018. The report provides a long-term energy analysis from today to 2040. The report does not make predictions about the future but sets out what the future could look like based on different scenarios. The three scenarios are the **New Policies Scenario**, the **Current Policies Scenario** and the **Sustainable Development Scenario**. The New Policies Scenario is the main scenario and *“provides a measured assessment of where today’s policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades”*(International Energy Agency, 2018). The report shows that in the New Policies Scenario, the world primary energy demand will grow with approximately 26% between today and 2040, with an increasing world population, urbanization and economic growth being the main contributors in shaping the demand. The majority of the growth will come in developing economies, where India and China are the front runners, while the European Union is likely to see a decline in energy demand largely due to energy efficiency gains (International Energy Agency, 2018).

1.2. Outlook for natural gas in the world and in Europe

1.2.1. World demand

Natural gas is expected to be the fastest growing fossil fuel in the New Policies Scenario, and approximately 35% of the increase in global primary energy demand will be covered by gas. Growth is expected in all regions, but again the Asia Pacific region is the main contributor. China’s initiative to “turn China’s skies blue again” provides a strong governmental push to switch from coal to gas in industry and domestic heating, and China is expected to stand behind nearly 30% of the demand growth. The industry sector is expected to be the main source of growth with the power sector being the second largest. (International Energy Agency, 2018) The share of gas in the energy mix by region for the New Policies Scenario is shown in Figure 1.1.

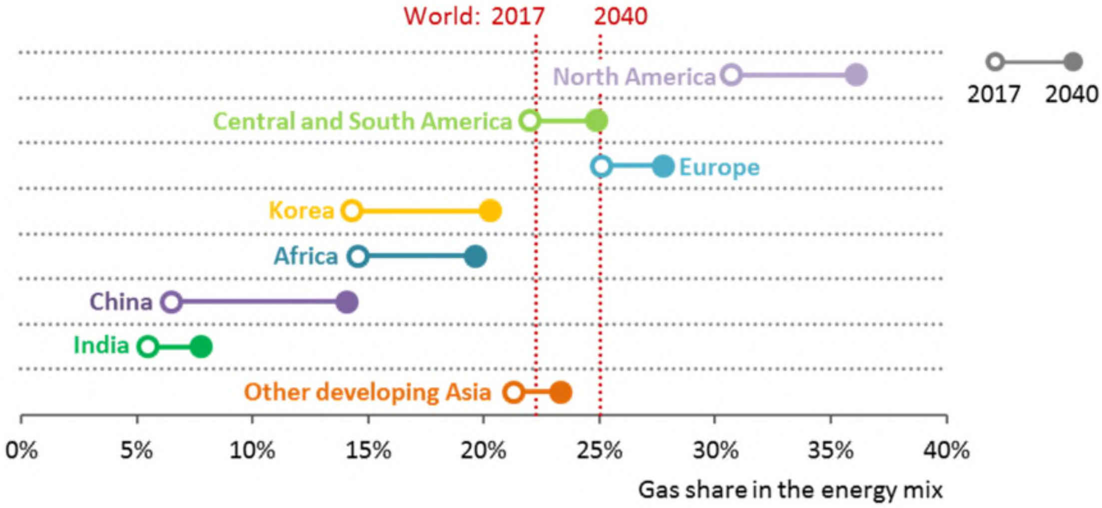


Figure 1.1: Share of gas in the energy mix by region in the New Policies Scenario (International Energy Agency, 2018, World Energy Outlook 2018, OECD/IEA, Paris).

The expected increase in energy demand needs to be met by an increase in production. The increase in production until 2025 will mainly be covered by the current major producers, while the growth will be linked to a more diverse range of producer countries from 2025 to 2040. The share of conventional gas is expected to drop from todays 80% to 70% by 2040, with the Middle East and Russia being the main drivers of growth in this segment. Offshore production will account for an increasing share of conventional production, reaching almost half by 2040, with deep-water being particularly important (International Energy Agency, 2018). Figure 1.2 shows gas production growth by region in the New Policies Scenario.

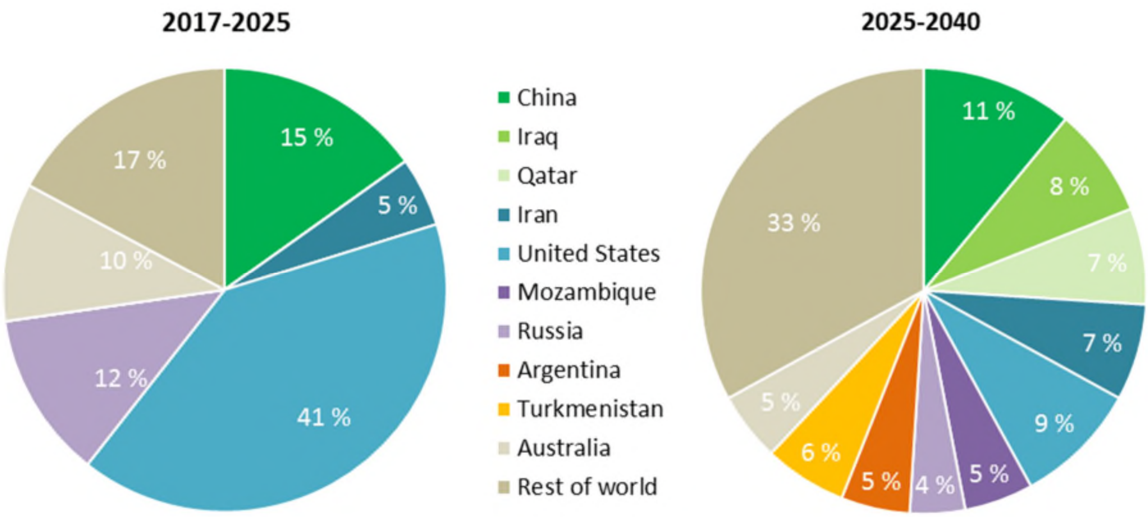


Figure 1.2: Share by region in gas production growth in the New Policies Scenario (International Energy Agency, 2018, World Energy Outlook 2018, OECD/IEA, Paris).

1.2.2. Demand in Europe

The primary energy demand of Europe is expected to decline in the period up to 2040. This is linked to the European Union's "Clean Energy Package" containing the Energy Efficiency Directive, which targets a 32.5% increase in energy efficiency in the European Union by 2030. Despite the decline in energy demand, the outlook for natural gas demand still remains fairly stable, as can be seen in Figure 1.3 (International Energy Agency, 2018). This is explained by an increasing share of natural gas in the energy mix. Following the Fukushima nuclear disaster, Germany closed down several nuclear plants, and the remaining will be closed by 2022. Climate and environmental policies and directives such as the Industrial Emissions Directive, setting emissions limits that will affect many power plants, and Best Available Technique regulations for large combustion plants, provide further support in a fuel switch from coal to gas, resulting in the closure of 50% of coal fired capacity by 2030. (International Energy Agency, 2018) There is a strong drive towards an increasing part of variable renewable energy sources, backed by the Renewable Energy Directive which targets 32% of energy consumption from renewable sources at EU level for 2030, but gas-fired power plants will still play an important role in providing the required flexibility to meet seasonal peaks in electricity demand (International Energy Agency, 2018).

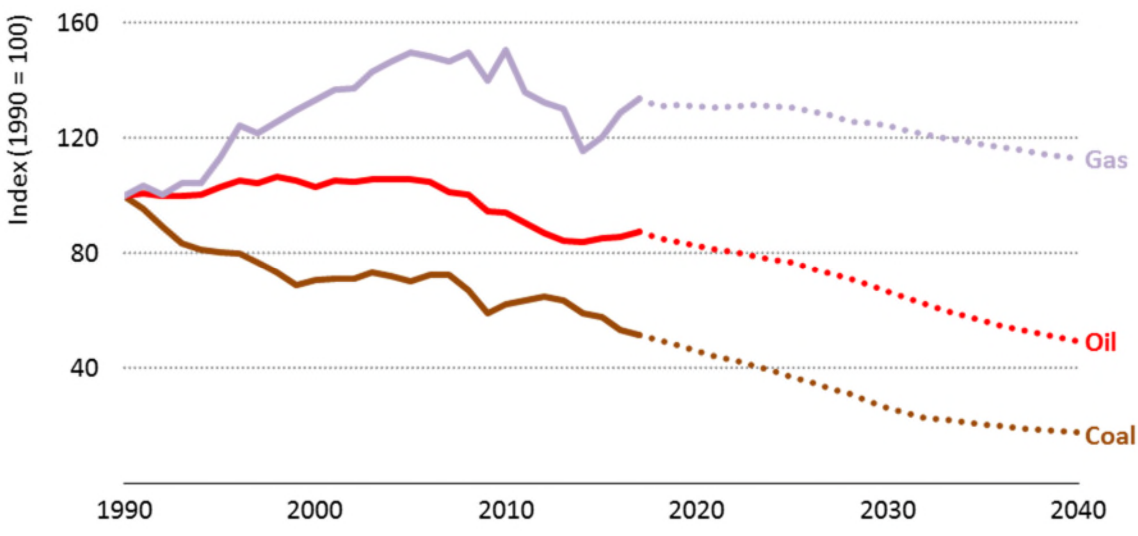


Figure 1.3: Demand for gas, oil and coal in the European Union in the New Policies Scenario (International Energy Agency, 2018, World Energy Outlook 2018, OECD/IEA, Paris).

1.3. Paris Agreement

The Paris Agreement was signed at COP 21 (Conference of the Parties) on the 12th of December in 2015 and entered into force on the 4th of November in 2016. The agreement targets *"holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C"* (United Nations, 2015). All parties are required to create their nationally determined contributions (NDC) for how they aim to reduce their emissions to tackle impacts of climate change in line with the goals in the Paris Agreement, and are required to report on progress and update their goals every 5th year. Norway's NDC are aligned with the target the EU has set to reduce greenhouse gas emissions by at least 40% by 2030 compared to 1990 (Latvia and The European Commission, 2015). The Intergovernmental Panel on Climate Change (IPCC) published their "Special Report on the Impacts of Global Warming of 1.5°C" (IPCC, 2018) on the 7th of October further describing the required measures to meet these related targets.

1.4. The Emission Trading System

In 2005 the European Union introduced the first major international Emission Trading System (ETS) to combat climate change. The system works on a cap-and-trade principle where a limit is set on overall emissions from the installations covered by the system. Introducing a carbon-market allows the market to find the cheapest way of reducing emissions, still reaching the overall targets set out by the regulators. At the end of each year, companies need to surrender enough allowances to cover all its emissions. One allowance covers one tonne of CO_2 equivalents. The allocation of allowances has been done by a combination of free allocation and auctioning, depending upon in which sector the companies operate. The system covers about 45% of the EUs total emissions. (European Comission, n.d.)

A phased development has taken place and we are currently in the 3rd trading period lasting from 2013 to 2020. In the 3rd period the free allocation to manufacturing industry has gradually decreased from 80% in 2013 to 30% in 2020, and the total amount of allowances has been reduced with 1.74% each year. Due to the financial crisis and resulting economic downturn, the demand for ETS allowances fell more than expected from 2009, leading to a surplus of allowances in the market and falling CO_2 emission prices. Major reform was therefore introduced in 2015, when it was decided a Market Stability Reserve (MSR) would be implemented from January 2019. Based on allowances in circulation and pre-defined mechanisms, the available auction volumes will be adjusted, and the remaining allowances will be transferred to the MSR. In Phase 4 starting from 2021 to 2030 the pace of annual reductions in allowances is increased to 2.2% (European Comission, n.d.). The price of CO_2

European Emission Allowances has increased drastically over the last year as shown in Figure 1.4.

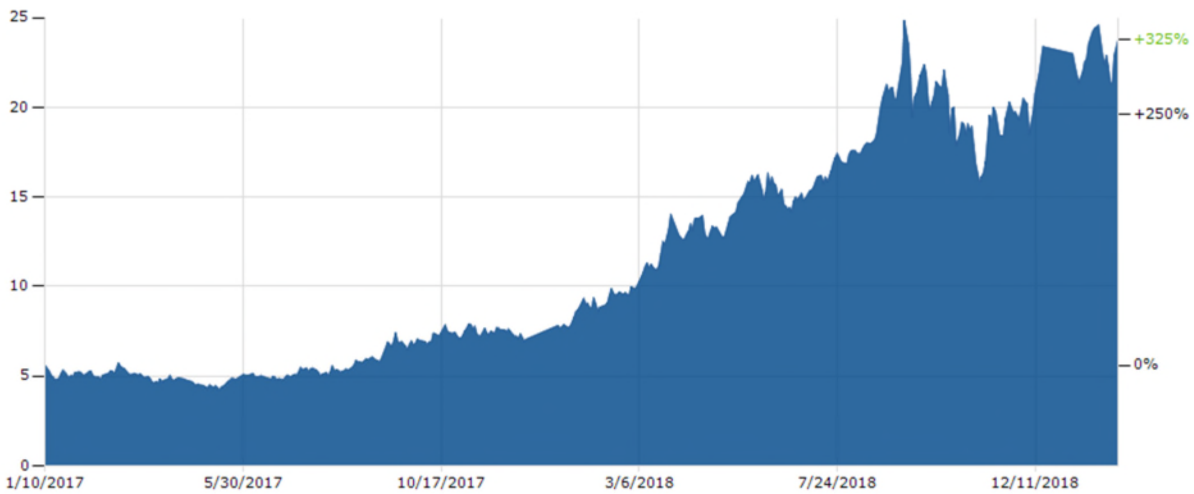


Figure 1.4: CO_2 European emission allowances in euro (Markets Insider, n.d.).

1.5. CO_2 intensity in hydrocarbon production

The International Association of Oil & Gas Producers (IOGP) has collected environmental data from their member companies since 1990, with the objective to let the member companies compare their performance with one another and possibly improve their operations. One of the statistics they publish is the estimated CO_2 emissions per unit of hydrocarbon production. Their report "Environmental performance indicators – 2017 data" (International Association of Oil & Gas Producers, 2018) shows that the average emissions rose by three present to 18.1 kilos of CO_2 per barrel of oil equivalent (BOE) from 2016 to 2017 for the 2016 participating members. The data is based on submission from 43 member companies (International Association of Oil & Gas Producers, 2018). The development in emissions is shown in Figure 1.5.

The Norwegian operator Equinor estimates the carbon intensity of their upstream production to be around 10 kilos of CO_2 per BOE and has a target to reduce that to 9 kilos by 2020. This is significantly better than the world average. By 2030 they have an ambition to be at 8 kilos of CO_2 per BOE (Equinor, n.d.-a). The increased focus on carbon intensity from the operators, makes developing new technology and improved solutions a key priority for the supply chain industry to secure a sustainable future in the energy transition and in winning new work.

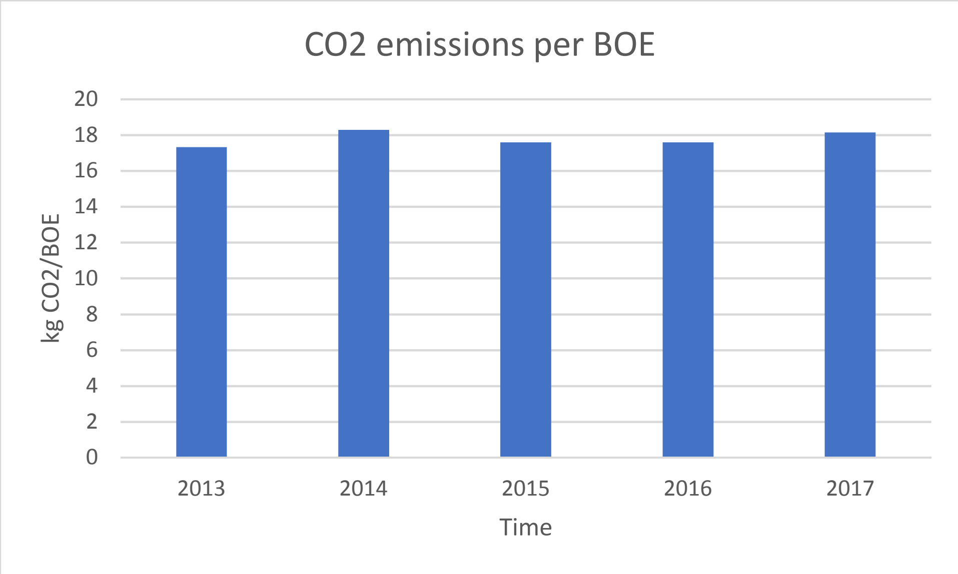


Figure 1.5: CO_2 emissions per BOE for IOGP member companies (International Association of Oil & Gas Producers, 2018).

1.6. Best Available Techniques

Both the Pollution Control Act and the Industrial Emissions Directive 2010/75/EU call out for best available techniques (BAT) assessments as a requirement to obtain permits for operation and installation in Norway and in the EU. Circumstances that needs to be considered in the evaluation of BAT include evaluations of design and operational considerations, costs including pros and cons, and a complete evaluation of the environmental impact of the planned installation. The ambition with the BAT regulations is that the technology that aligns best with the guidelines in the directives shall be used, such that a field development plan is not optimized on a subjective basis. As gas will be a part of the future energy mix, it needs to be produced in the most efficient way with lowest possible emissions.

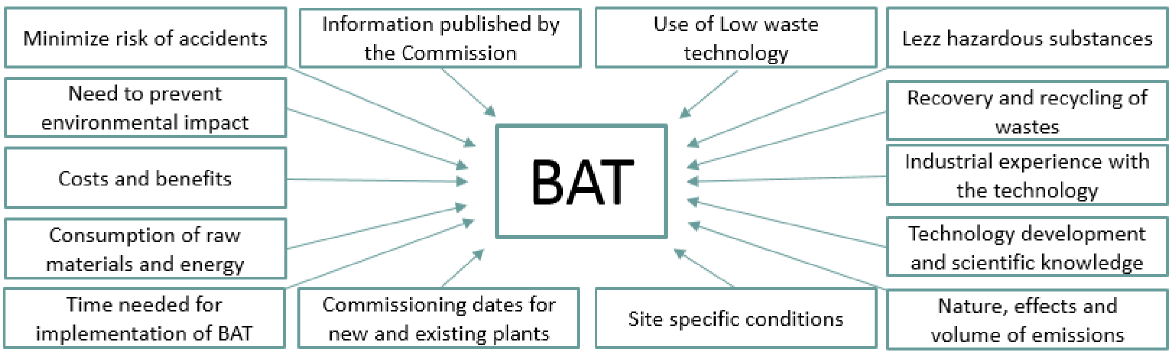


Figure 1.6: Best Available Techniques considerations (Norsk Standard, 2005, cited inStatoil, 2011).

2. Technical Background

2.1. Improved recovery

A common opinion amongst policy makers and operators is that the recovery rate of each reservoir needs to be maximized as long as profitable production can be maintained. A typical production profile for a hydrocarbon gas or gas-condensate reservoir will show three distinct phases. A rapid increase to a maximum production rate, followed by stable production plateau at the maximum production rate, and a production rate decline due to a falling reservoir pressure until the field is eventually abandoned. The maximum production rate at the plateau will typically be limited by the receiving process facility. At the plateau rate, the production will be choked by valves to not overload the receiving facility. The chokes gradually open as the reservoir pressure declines, until choking is no longer necessary. This point in time defines the end of the production plateau. As the natural energy of the reservoir declines and there is no longer any need to regulate the production rate, energy can be added to the reservoir to maintain the production rate at plateau for a longer period to utilize the full capacity of the infrastructure. Adding energy to increase production is referred to as improved recovery and a typical production profile with and without improved recovery is shown in Figure 2.1.

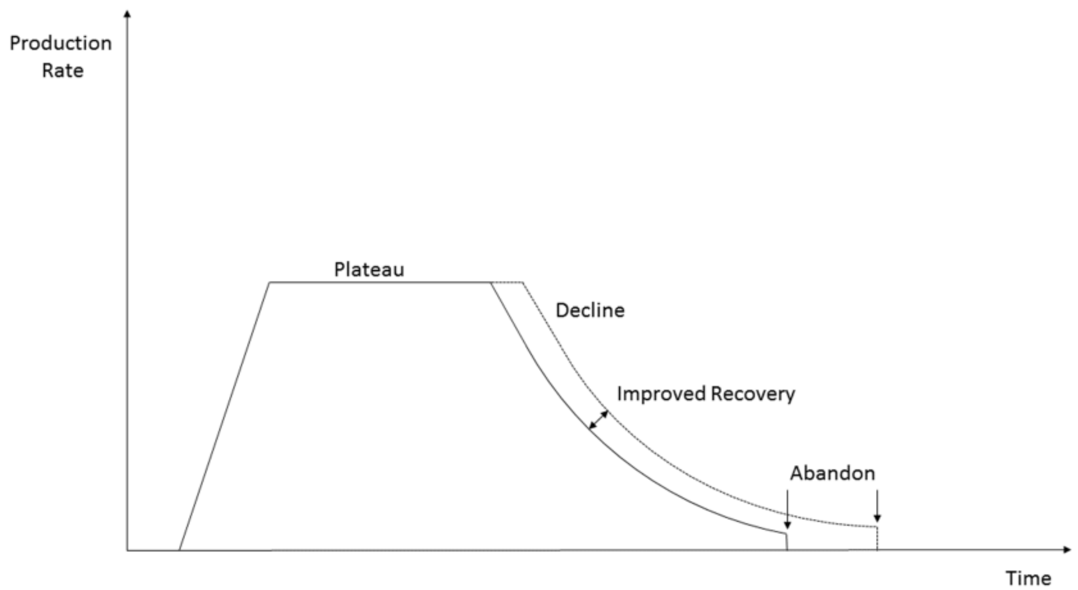


Figure 2.1: Production profile for a typical gas-condensate reservoir showing impact of improved recovery.

Due to difference in reservoir drive the production profile will look a bit different for an oil reservoir when considering the complete well stream. Gas fields are usually driven by the expansion of the gas itself, but oil fields are more complex. Oil fields generally have an increase in water production over time, meaning the overall liquid rate can remain similar over the lifetime also when the oil production rate is declining. The reduction of produced oil is mainly caused by an increase in produced water.

There are several ways to improve the recovery of a hydrocarbon reservoir which will be further described in the following sections. The average recovery rate for oil fields on the Norwegian Continental Shelf is approximately 47%, and approximately 70% for gas fields (Norwegian Petroleum, n.d.).

2.2. Methods to improve recovery of Oil Reservoirs

2.2.1. Injection of water and gas

One of the most common ways of increasing recovery of oil fields is to inject water into the reservoir. Most oil fields are equipped with water injection facilities from the start-up to avoid early reduction in production rates. Injection wells can be drilled into the reservoir in a variety of ways, and finding the best solution will be part of the operator's strategy to maximize recovery. The injection water will typically be brine, but can also be treated water that is separated from the well stream in reservoirs where water is part of the production. The injected water will replace the produced oil and help to maintain the reservoir pressure, as well as moving the remaining oil through the reservoir closer to the production wells where it can be recovered (Rigzone, n.d.-b). As water injection continues, the injected water will typically get closer to the production well and eventually break through and enter the production. As the water cut progressively increases, the profitability of the reservoir will fall and at some point, become unprofitable if further actions are not implemented.

As an alternative to injecting water, gas can also be used for injection purposes to improve oil recovery. Gas will be injected in the top of the reservoir in the gas cap to maintain reservoir pressure. Injection of gas can also serve as an economical way to dispose of uneconomical gas production. Gas injection can be done in conjunction with water injection, referred to as alternating water and gas injection. Oseberg was the first field in Norway where gas injection was approved as the main method of increasing recovery, where both gas produced from the reservoir and gas from the neighboring Troll field was used for injection (Norwegian Petroleum Directorate, n.d.). Figure 2.2 shows a typical subsea production system with injection wells and production wells.

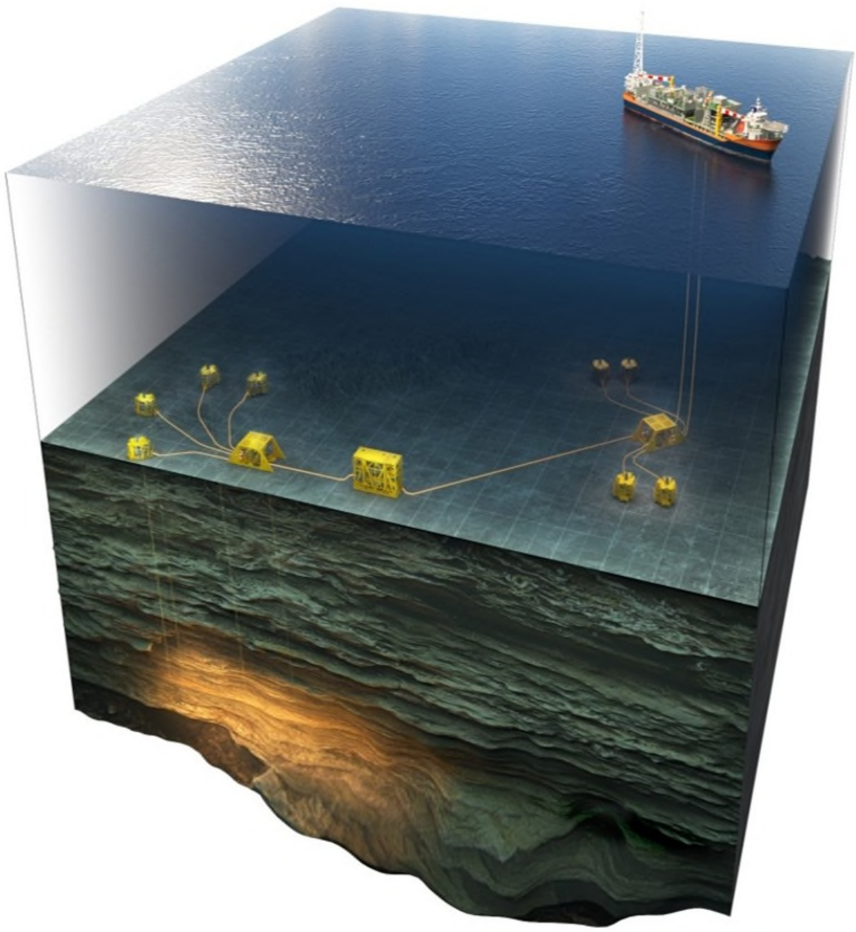


Figure 2.2: Subsea production system with injection wells and production wells. Courtesy of Aker Solutions.

2.2.2. CO_2 Enhanced Oil Recovery

CO_2 Enhanced Oil Recovery (EOR) has been used for onshore wells in North America with good results for many years. Injection of CO_2 can be compared with injection of natural gas, but the CO_2 has certain characteristics differing from natural gas. In addition to maintaining pressure and moving remaining oil closer to the production wells, the properties of CO_2 will reduce the capillary forces that traps the oil in the reservoir rock and will create better flowing properties. (International Energy Agency, 2015) Recently, there has been an increased focus on how developments in technology can be used to implement CO_2 EOR offshore.

Historically, CO_2 EOR has been used as a means to increase recovery but is now also being discussed as a tool to combat climate change if it can be combined with permanent storage of the CO_2. A simplified process diagram for an example of a potential subsea CO_2 EOR application is shown in Figure 2.3 below. In this application it is assumed external CO_2 will be available for injection and it is further combined with a subsea compression system.

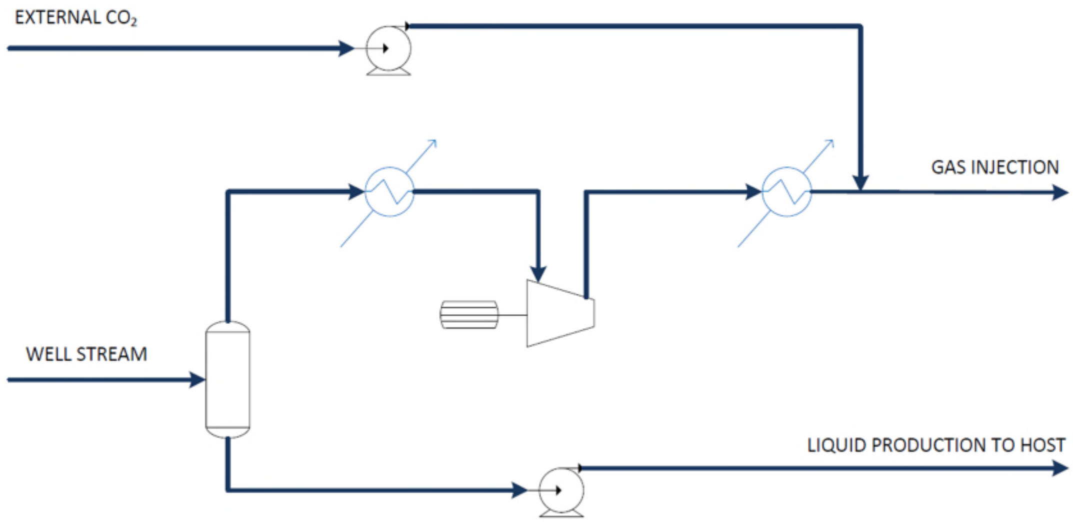


Figure 2.3: Simplified process diagram - CO_2 EOR.

In the system above, the well stream enters a gas/liquid separator. The liquid is boosted by a pump and routed to the host facility. The gas is cooled and then compressed. The compressed gas discharge enters another cooler and mixes with the externally provided CO_2 before it is re-injected into the reservoir. As more CO_2 is injected into the well over time, the content of CO_2 in the produced gas will increase. There are currently ongoing studies looking into the feasibility of full-scale carbon capture and storage in Norway, and the current project schedule indicates that an investment decisions will be made in 2020/2021 (Gassnova, n.d.).

2.2.3. Gas lift

In addition to injection of water and gas, there are further methods to increase the recovery rate from an oil reservoir. A general term for this is called artificial lift, and these methods consist of lowering the flowing bottomhole pressure (FBHP) on the formation, resulting in a higher production rate from the well (PetroWiki, n.d.-a). The methods vary a bit for offshore and onshore applications, but will also be the same in many cases. Gas lift is a method of artificial lift that consists of introducing an external source of high-pressure gas into the well stream to reduce the average density of the fluid mixture. The lowered density will result in a lower weight of the hydrostatic column, reducing the FBHP and increasing the production rate. (PetroWiki, n.d.-b) The gas will be injected down through the annulus, which is the space between the production tubing and outer casing, and will enter the well stream via gas lift valves as shown in Figure 2.4 below. The gas will typically be injected as low down in the well as possible to maximize the effect of the gas lift.

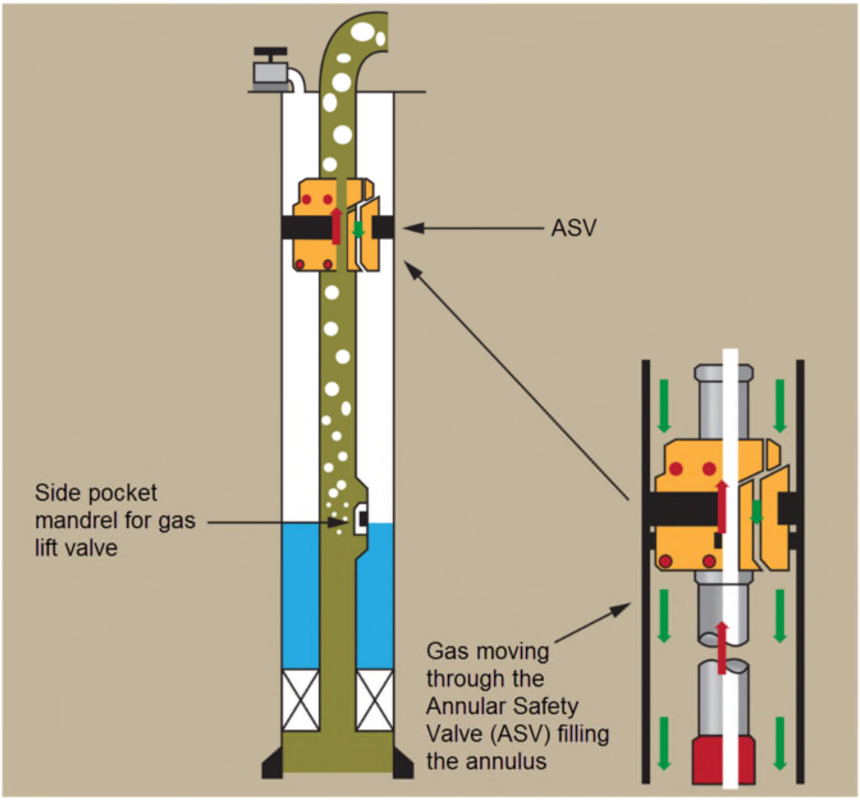


Figure 2.4: Paaske, S. (n.d.) *Gas lift valve and ASV*. Available at: https://ndla.no/subjects/subject:6/topic:1:182061/topic:1:151959/resource:1:181801, Creative Commons license Attribution-ShareAlike 4.0 International (CC BY-SA 4.0), modified, (access date 30.04.2019).

2.2.4. Subsea Pumping

Subsea pumping is another way of boosting production from an oil reservoir. The first installation of a subsea multiphase pump was on the Shell operated Draugen field back in 1994 (Oil & Gas Journal, 1995). By adding energy to the well stream the back pressure applied to the wells is reduced, helping to transfer the production to the sea surface or the host facility. The technology is typically applied on deepwater fields, or where the production needs to be transported over long distances, but can also be used for mid-water applications to further increase recovery (Rigzone, n.d.-a).

2.3. Methods to improve recovery of Gas Reservoirs

2.3.1. Gas compression

The above-mentioned methods can help to increase recovery from oil reservoirs, but will be of little help when trying to drain a gas reservoir. As the natural pressure of the gas reservoir declines, the weight of the gas column will start to constrain the recovery rate at some point. Another typical problem for gas reservoirs is related to the transport capabilities of the pipelines. A reduction in flow can result in flow-issues where liquid accumulates in the flowlines, creating instabilities in the production and eventually leading to discontinuation of gas production (Lima et al., 2011). Installing a compression system has been a solution to these type of issues for a long time. By boosting the well stream the pressure will increase after the compressor, helping to retain a higher production rate, accelerate recovery and manage the flow-related challenges. Traditionally these systems have been installed topside or onshore, but in recent years subsea compression systems have been installed both on the Åsgard and the Gullfaks gas fields on the Norwegian continental shelf (Vinterstø et al., 2016).

2.3.2. Subsea dry gas compression

In the field of subsea compression, there are mainly two alternative technologies available in the market today, dry gas compression (DGC) and wet gas compression (WGC). In DGC, the well stream will typically go through an inlet cooler before entering a scrubber module where the well stream is separated into condensate and gas. The condensate will exit at the bottom of the scrubber where it will enter a pump which boosts the pressure for further transport. The gas will exit at the top of the scrubber before entering the compressor. After the gas is compressed it will go through a discharge cooler before it is mixed with the pressurized condensate and transported further to the host facility (Tønnesen & Romanello, 2017). A simplified PFD for a possible DGC system is shown in Figure 2.5 below.

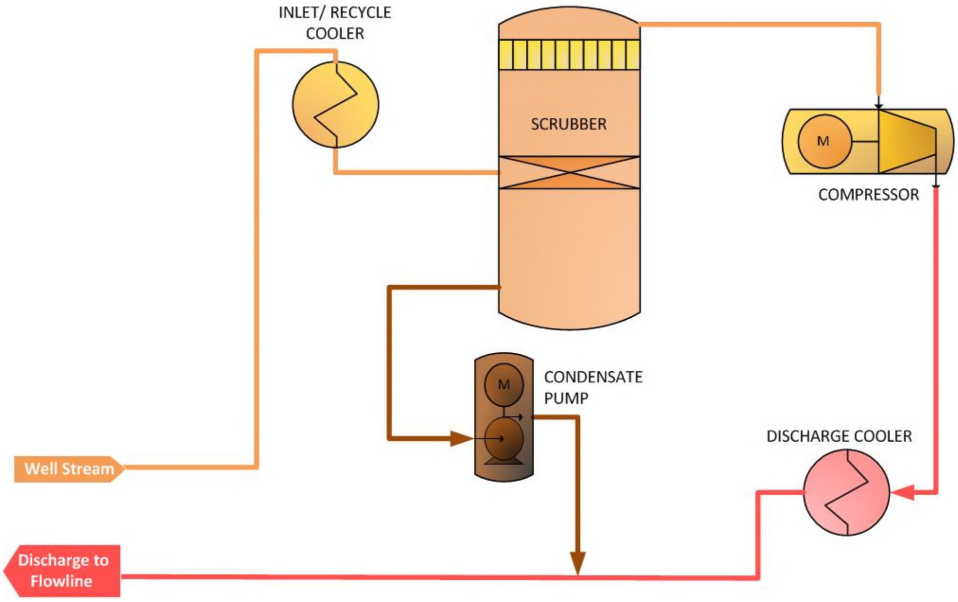


Figure 2.5: Simplified PFD for a subsea dry gas compression system.

2.3.3. Subsea wet gas compression

The alternative to dry gas compression is wet gas compression. In the WGC system the main difference is that there will be no separation of the well stream before entering the compressor, hence requiring no pump to boost separated liquids. To cope with the liquid content in the well stream, the WGC system is equipped with a multiphase wet gas compressor, and will typically be dependent on a flow condition unit (FCU) upstream of the compressor to cope with transients and to keep the inlet conditions to the compressor stable. Avoiding separation and pumping simplifies the system significantly and reduces cost and size, but the WGC system has limitations in that it requires considerably more power than a DGC system. The power ratio between WGC and DGC can range from close to one to beyond two dependent on field data (Tønnesen & Romanello, 2017). A simplified PFD for a possible WGC system is shown in Figure 2.6.

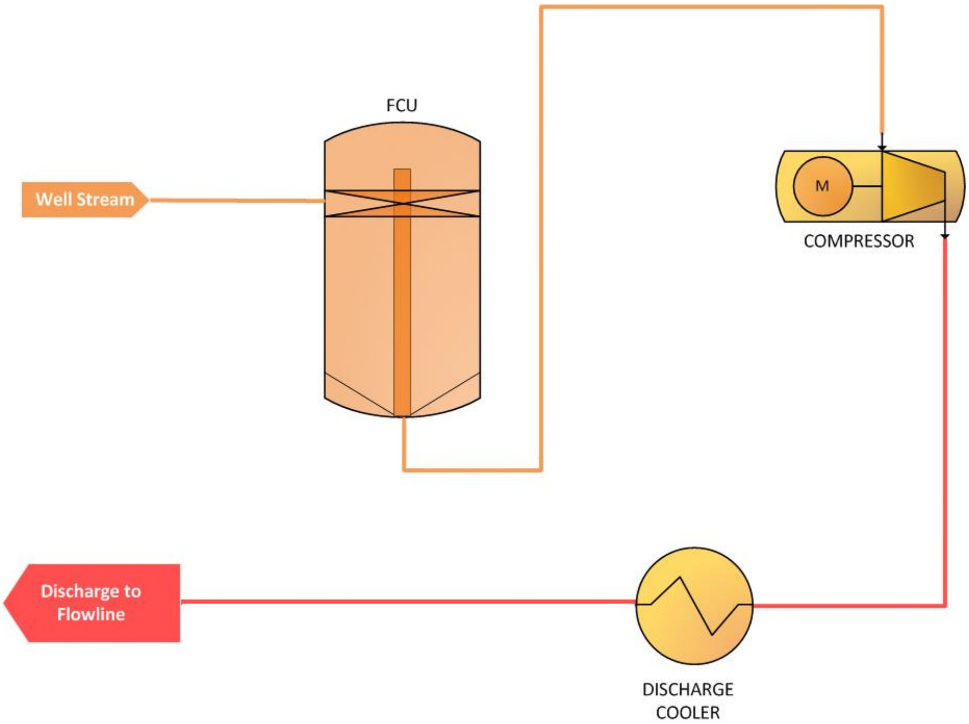


Figure 2.6: Simplified PFD for a subsea wet gas compression system.

2.3.4. Topside compression

Conventional top side compression is typically configured much like the subsea DGC system, in the way that the well stream starts of being separated before being further processed as liquid and gas. The topside compression system can be placed on an existing topside infrastructure if any spare capacity for additional equipment is available. In many cases however, existing platforms will have very limited space for additional equipment, meaning a separate compression facility will need to be manufactured. Creating a separate facility can in some cases also be desirable to provide the best possible business case.

2.3.5. Differences between subsea and topside compression

Both topside and subsea compression systems target increased recovery. The subsea compression station has the advantage that it can be placed closer to the well. Placing the subsea compressor upstream of a riser or tie-back pipeline allows for a lower pressure drop before the compressor, allowing a further draw down of the flowing wellhead pressure (Lima et al., 2011). As the pressure in the reservoir starts dropping towards ~20 bar, the actual flow will increase dramatically as illustrated in Figure 2.7. The increase in actual flow will result in a higher pressure-loss due to increased friction.

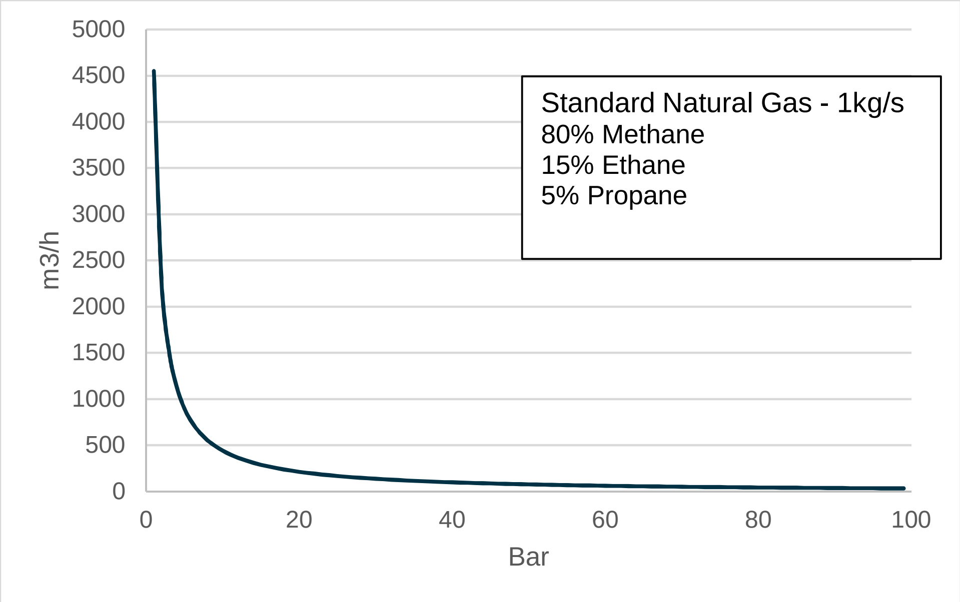


Figure 2.7: Change in actual volume flow with pressure of a standard natural gas.

If a topside compression system can be placed directly over the location where the subsea compression system is placed, the main difference in pressure drop will be in the riser from seabed and up to the platform. Important factors in this relation will be water depth and size of the riser. If the compressor is placed on shore on the other hand, the pressure drop in the whole upstream pipeline will come into play.

3. Historical Work and Existing Solutions

Subsea compression technology is still quite new in an operational perspective, but has been under development for a long time. This chapter will provide a brief summary of how the subsea oil and gas industry approach technology qualification and how the industry has come to the place it is today with actual systems installed in the field. Although some qualification will typically be required for new projects, subsea compression technology should no longer be considered novel technology, but rather be seen as another tool in helping to develop resources in the most effective manner.

3.1. Technology qualification and maturity

The technology qualification approach in the subsea oil and gas industry is mainly based on the technology readiness level (TRL) system originally developed by NASA (Bakke, 2017). The approach is further described in "API 17N - Recommended Practice on Subsea Production System Reliability, Technical Risk, and Integrity Management" (American Petroleum Institue, 2017) which is a Recommended Practice (RP) created specifically for subsea systems. The RP provides a definition of TRL, listed in Table 3.1. DNV GL has a slightly different approach in "DNVGL-RP-A203 - Technology Qualification" (DNV GL, 2017) which is another RP for technology qualification. Both RPs are widely applied in the oil and gas subsea industry and the geographical location of a project will typically be governing for which one is used. The DNV GL RP does not include its own definition of TRL but refers to API 17N among others.

Table 3.1: Definition of Technology Readiness Levels (American Petroleum Institue, 2017).

TRL 0	*Basic Research: Basic R&D paper concept*
TRL 1	*Concept Selection: Proof of concept as a paper study or R&D experiments*
TRL 2	*Concept Demonstration: Experimental proof of concept using physical model tests*
TRL 3	*Prototype Development: System function, performance, and reliability tested*
TRL 4	*Product Validation: Pre-production system validated and environment tested*
TRL 5	*System Integration Testing: Production system interface tested*
TRL 6	*System Installed: Production system installed and tested*
TRL 7	*System Operation: Production system field proven*

The topside compression technology has been available for a long time and is field proven. Getting the subsea compression technology ready for installation in the field has been a long journey. Both a wet gas and a dry gas compression system were installed subsea in 2015, but this was only possible as a result of a stepwise technology development over several decades. The world's first patent on a subsea gas compressor was granted in 1991, as a result of the Kvaerner Booster Station development (Lima et al., 2011). As part of the Demo 2000 project, a government backed program for technology development in the Norwegian petroleum sector, a helico-axial compressor design from Framo Engineering was later demonstrated in 2003. Aker Solutions' GasBooster™ was also part of the Demo 2000 program.

Qualification of components ramped-up in the later 2000s, then backed by Equinor, targeting to close technology gaps related to the Gullfaks and Åsgard projects. An up-rated version of the helico-axial multiphase compressor from Framo Engineering started a qualification program in 2009. The compressor was specifically designed for the operating conditions at Gullfaks and the program resulted in being awarded TRL 4 from Equinor (Scandinavian Oil-Gas Magazine, 2015). In addition, an extensive technology qualification program was established in relation with the Åsgård Subsea Compression System from 2007-2013. Compressor testing for Åsgard began at Equinor's testing facility K-lab, which is located next to the Kårstø gas plant near Stavanger in Norway, and submerged testing was successfully completed in 2014 (Vinterstø et al., 2016). Several qualification milestones were also achieved in relation with the Ormen Lange Subsea Compression Pilot project. After successful installation and operation of both the Gullfaks Wet Gas Compression System and the Åsgard Subsea Compression System, both the subsea wet gas and dry gas compression technology now hold TRL 7 and are considered field proven.

3.2. Ormen Lange Subsea Compression Pilot

Ormen Lange is a gas field located in the Norwegian Sea, about 120 kilometers north west of Kristiansund. The subsea production system is developed with 19 wells distributed in 4 subsea templates in water depths ranging from 800 to 1100 meters. The gas is transported to the land facility in Nyhamna through two 30-inch pipelines, where it is further separated into natural gas and condensate for export. Nyhamna is further connected to the UK through one of the longest subsea pipelines in the world, measuring about 1200 kilometers. (Norske Shell, n.d.) As part of the development plan to maintain production from the field, Ormen Lange Subsea Compression Pilot project was initiated in 2006. The project consisted in developing a full-size pilot project, where a submerged compressor would be installed in a test-pit, running actual hydrocarbons from the Ormen Lange reservoirs. This was done to qualify the technology for implementation at a later stage. Aker Solutions was selected for delivering the subsea compression system for the pilot testing, which consisted of a single compressor train with a complete subsea power distribution and all-electric control system. The system included a scrubber for separation of the well stream, a 12.5 MW centrifugal compressor, a 400 kW liquid pump and an anti-surge cooler. The power system consisted of a circuit breaker, frequency converters for the compressor and pump, and transformers (Lima et al., 2011). Substantial testing was completed successfully over a period of several years, but the project was put on hold in 2014 due to increasing costs in Norway's offshore oil sector. In 2019 it was finally decided that the field will be developed with a subsea compression solution, and the final decision on compression concept is expected late 2019.

Figure 3.1: Ormen Lange Subsea Compression Pilot testing. Courtesy of Aker Solutions, Photo: Relevant Film AS

3.3. Åsgard Subsea Compression System

The Åsgard field is located in Haltenbanken, approximately 200 km west off mid-Norway. The field consists of the Midgard, Smørbukk and Smørbukk south assets. The Mikkel gas field, located close to 40 km away, is also tided back to the Åsgard infrastructure. The development ranks as one of the largest developments on NCS, with 63 production and injection wells separated on 19 subsea templates. In the mid-2000s, it became clear that the gas from Midgard and Mikkel would need pressure support to sustain production (Time & Torpe, 2016). After a series of studies, the contract was awarded to Aker Solutions in December 2010 for delivery of the Åsgard Subsea Compression System. The system was installed successfully in 2015, and comprises of two identical compressor trains with a combined capacity of 21 million Sm3/day at full production. Production from Mikkel and Midgard enters a new manifold station, distributing the flow further to the two compressor trains. Each compressor train is fitted with a scrubber to separate the multiphase flow, a 700 kW centrifugal pump to boost the liquid flow, and an 11 MW centrifugal compressor with inlet and outlet coolers. The power and control signals for the compressor station are supplied through umbilical from the Åsgard A FPSO, which is located approximately 45 km away from the compression station. The system is expected to secure recovery of an additional 306 million barrels of oil equivalents over its lifetime, and increase recovery from 67% to 87% on Midgard and from 59% to 84% on Mikkel (Vinterstø et al., 2016).

3.4. Gullfaks Wet Gas Compression System

Gullfaks South is a satellite to the main Gullfaks field located approximately 175 km northwest of Bergen in water depths ranging from 130-220 meters. In 2015 a wet gas compression system was installed at Gullfaks South. The system was delivered by OneSubsea and was the first system to be installed without any need for a separation facility upstream the compressor. The system was installed at a water depth of 135 m to boost the well stream from existing wells and was expected to handle a flow rate of 10 million Sm3/d. The system comprises of two 5 MW helico-axial multiphase compressors, powered by two 2.5 MW electric motors each driving the contra rotating impellers. The power to the compressor station is provided through a 15 km power and controls umbilical coming from the Gullfaks C platform. The compressor station is expected to increase recovery by 22 million barrels of oil equivalents over its lifetime, and increase recovery from 63 to 73% (Vinterstø et al., 2016).

4. Integrated Production Modeling

The CO_2 emissions from a subsea compression system and a topside compression system will correlate linearly to the energy consumption over the lifecycle. As the operational lifecycle and total energy consumption will be different for the two systems, a measure of comparison needs to be established to be able to make a just comparison of the CO_2 emissions. This can be done by looking at the energy consumption over the lifecycle in relation to the accumulated gas production. A typical benchmark used in the industry is kilos of CO_2 emitted per BOE. Integrated Production Modeling (IPM) is used for predicting the production profile for oil and gas fields and will be used to find the required information for performing the comparison.

IPM is often used for evaluating development and production strategies for a hydrocarbon reservoir and is based on building a model to represent all the constraints from the reservoir to the receiving process facility. The main target is to find the optimal solution with regards to flow, pressure and resistance in the production system to maximize profitability. The production system modeling involves complex calculations that are solved using IPM software. Obtaining sufficient information on the reservoir, the wells, the production tubing, the pipelines and the receiving process facilities is key in the development of the production system model to get accurate results. When some key parameters are fixed, an optimization can be performed to find the best development strategy.

A simplified illustration of a subsea production system producing directly to an onshore host is shown in Figure 4.1. The flow resistance in a production system can be divided into three main parts: the inflow resistance in the reservoir; the resistance in the well and the subsea production system; and the resistance in the export pipeline. Maximizing the recovery rate of gas reservoirs involves trying to deplete the reservoir as much as possible and abandoning the reservoir with the lowest possible pressure. The system boundary conditions are the reservoir composition, reservoir pressure and the minimum arrival pressure required at the receiving host facility. Together with the production system resistance and any additional constraints, such as minimum flow rate or minimum FBHP, this ultimately decides the lowest achievable reservoir pressure with a given production system. In many cases the production flow will go through a process facility located on an offshore topside structure as shown in Figure 4.2. The main difference for the topside system is that the fluid will need to travel up and down through risers, before being exported to the host facility.

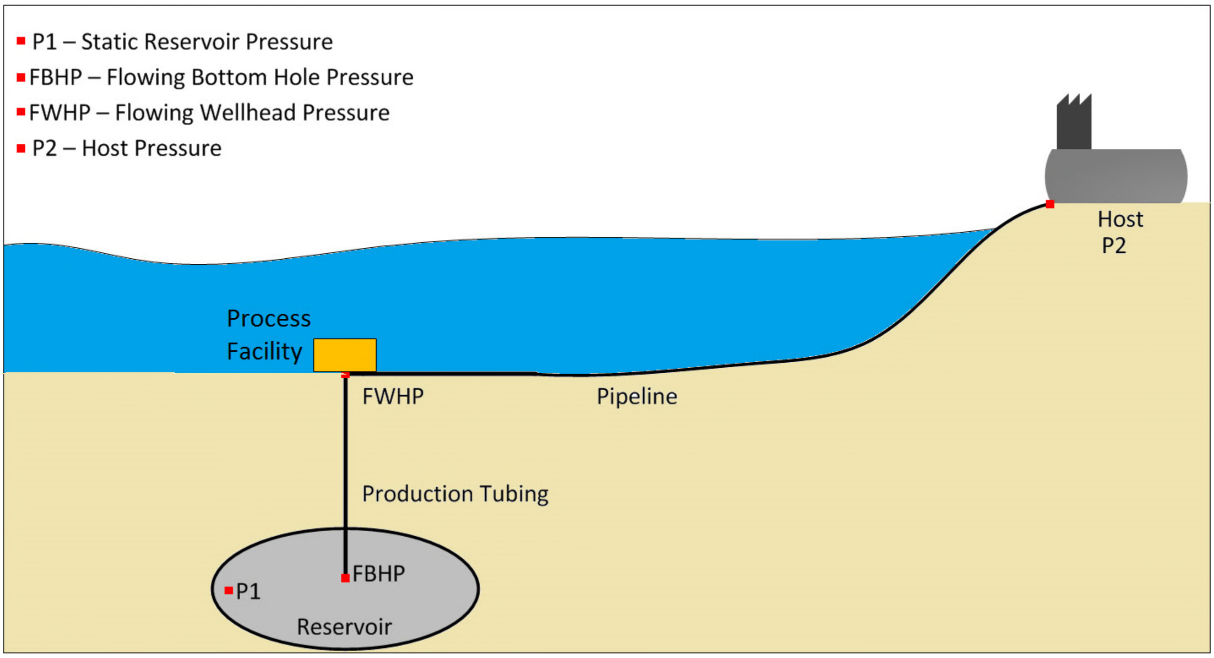


Figure 4.1: Subsea system.

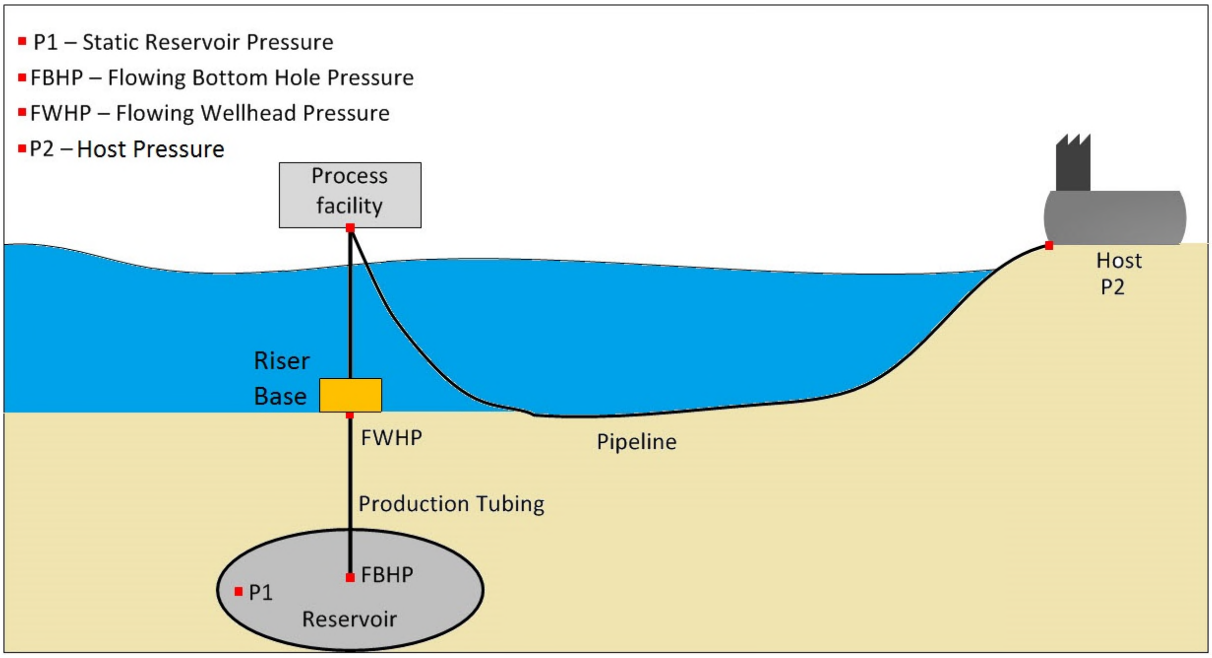


Figure 4.2: Topside system.

4.1. Reservoir pressure

The reservoir pressure is the measured pressure within the pores of a reservoir and will usually relate to the weight of the water column from the formations depth to sea-level

(Schlumberger, n.d.). The static reservoir pressure is found in the parts of the reservoir which is not influenced by the production flow, denoted by p_i in Figure 4.3. The figure illustrates the pressure profile as a function of the distance from the wellbore for a well producing at steady rate. When a well is put into production, the pressure close to the wellbore will rapidly decline before it stabilizes at the FBHP, denoted by p_{wf}. The distance from the wellbore to where the pressure stabilizes at the static reservoir pressure will depend on factors including permeability of the reservoir and fluid mixture viscosity. As the pressure is lower close to the wellbore, the fluid will flow towards the center of the well and the static pressure of the reservoir will gradually reduce as production continues.

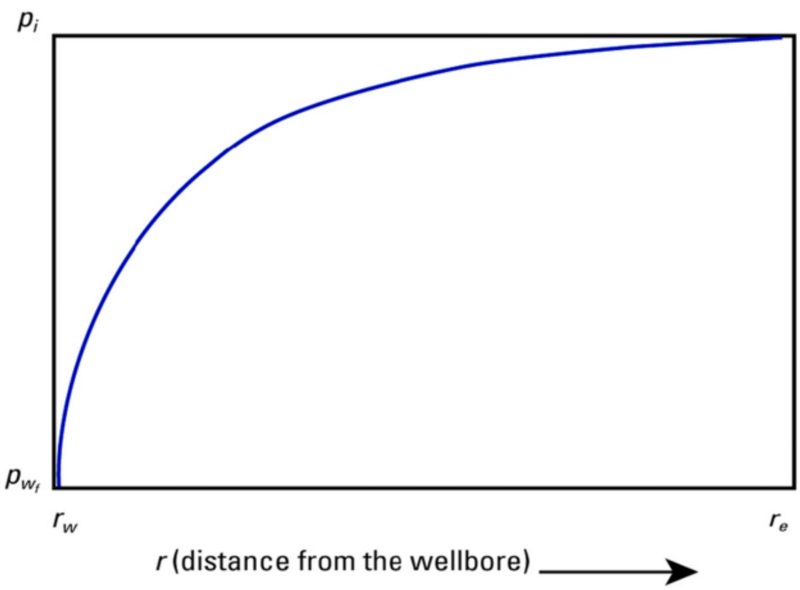


Figure 4.3: Pressure profile away from the wellbore (PetroWiki, n.d.-f).

4.2. Inflow performance relationship

Predicting the pressure drop from the reservoir to the bottom of the well can be done based on empirical correlations referred to as inflow performance relationships (IPR). Productivity index is often used for estimating the performance of an oil well and is defined as the ratio of total flow rate of the liquid (q) to the drawdown pressure. The drawdown pressure is defined as the delta between the FBHP, represented by p_{wf} in equation (4.1), and the static pressure of the average drainage area, represented by p_r in equation (4.1). The stabilized FBHP is measured after the well has produced at a constant flow rate for a certain amount of time, and the static reservoir pressure is measured after the well has been shut-in for a sufficient amount of time. The productivity index, denoted by J in equation (4.1), then typically provides a measure for stock tank barrel (STB)/day/Psi (Petropedia, n.d.).

$$J = \frac{q}{(p_r - p_{wf})} \tag{4.1}$$

For oil wells producing under single phase flow conditions where the reservoir pressure is higher than the oil's bubble point pressure, the constant productivity index provides good estimations. When the reservoir pressure goes below the bubble point pressure however, the gas in the oil will start to vaporize and the fluid will exist as two phases. At two-phase conditions other techniques of determining oil-well performance needs to be applied (PetroWiki, n.d.-d). A number of techniques are available, and one of the most commonly used is Vogel's (Vogel, 1968) IPR, which was constructed based on a number of computer simulations.

$$\frac{q_0}{q_{0,max}} = 1 - 0.2\left(\frac{p_{wf}}{\overline{p}_R}\right) - 0.8\left(\frac{p_{wf}}{\overline{p}_R}\right)^2 \tag{4.2}$$

With information from a production test on flow rate, corresponding FBHP (p_{wf}) and an estimate of the average reservoir pressure ($\overline{p}_R$), it is possible to determine the maximum flow rate, which can be further used to determine the flow rate at other FBHPs at the same average reservoir pressure. The FBHPs can then be plotted against corresponding flow rates to create a complete inflow performance curve (PetroWiki, n.d.-d). Another technique is to use Fetkovich's (Fetkovich, 1973) method with isochronal testing to determine well performance. Fetkovich based his equation on the gas-well deliverability equation (4.3) proposed by Rawlins and Schellhardt (Rawlins & Schellhardt, 1935), also called the backpressure equation.

$$q_0 = C\left({\overline{p}_R}^2 - {p_{wf}}^2\right)^n \tag{4.3}$$

By performing a multiple rate test, the values of C and n can be obtained and further used in equation (4.4) to create an IPR (PetroWiki, n.d.-d). Again, the maximum flow rate can be determined, and used to calculate other flow rates at other pressures to create the inflow performance curve.

$$\frac{q_0}{q_{0,max}} = \left[1 - \left(\frac{p_{wf}}{\overline{p}_R}\right)^2\right]^n \quad \textbf{(4.4)}$$

For high pressure gas wells, the backpressure equation (4.3) needs to be re-written in terms of pseudo-pressures as shown in equation (4.5), to account for the changes in compressibility and viscosity of gas with pressure. Pseudo-pressure is expressed by a mathematical pressure function (Al-Hussainy et al., 1966), and provides a rigorous transformation from pressure to pseudo-pressure and thereby allows us predict the performance also for high pressure gas wells. Equation (4.5) can be re-written to the same form as equation (4.4), now using pseudo-pressures instead of pressures squared, as shown in equation (4.6). Test data can then be used to calculate flow rates and the inflow performance curve (PetroWiki, n.d.-c). An example of an IPR curve is shown in Figure 4.4.

$$q_g = C\left[p_p(\overline{p}_R) - p_p(p_{wf})\right]^n \quad \textbf{(4.5)}$$

$$\frac{q_0}{q_{0,max}} = \left[1 - \left(\frac{p_p(p_{wf})}{p_p(\overline{p}_R)}\right)\right]^n \quad \textbf{(4.6)}$$

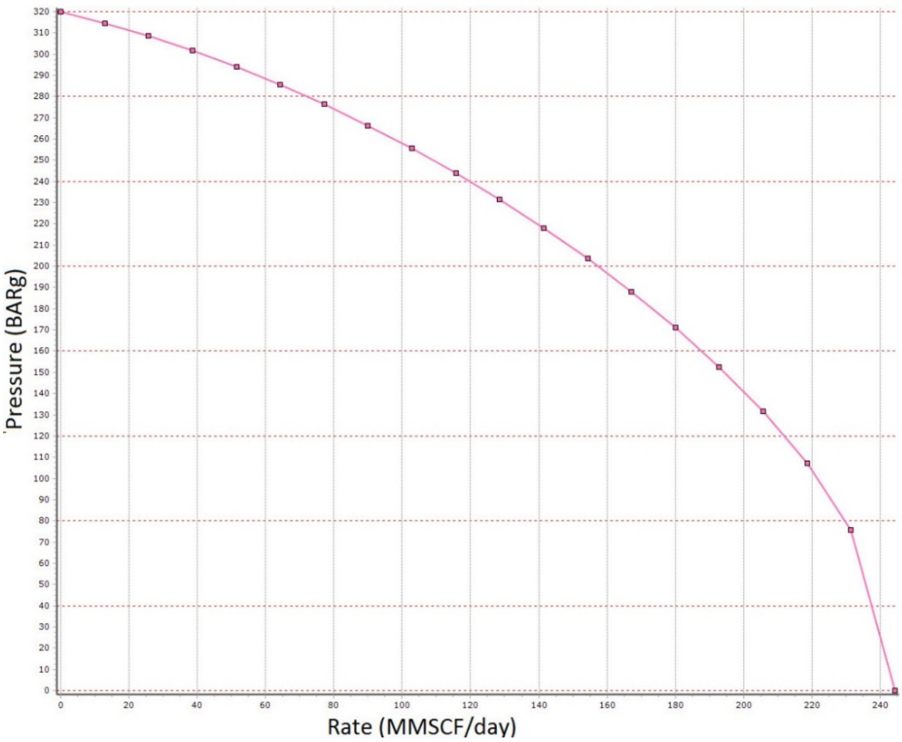


Figure 4.4: Example of IPR curve for gas well.

4.3. Wells, pipelines and risers: multiphase flow

The pressure loss from the well bottomhole to the host facility can be divided in two main parts. One is the pressure loss related to elevating the well stream up to the subsea or topside process facility and further up to the onshore terminal. The other is the pressure loss due to friction in the completion and production tubing, the process facility and the pipeline to the receiving host facility. When the production flow has entered the production bore through the perforations in the completion, it will flow further through the production tubing and up to the wellhead and process facility, and then further through the production pipeline to the host facility. The first part of this journey is described through the vertical lift performance relationship (VLP). The VLP describes how much fluids that can be lifted from the well up to the wellhead at a set of given conditions (Petroleum Experts, 2019).

The production flow from a reservoir will generally be multiphase. The well stream from an oil reservoir will consist of a majority of oil, typically with a mix of some gas and some water, while a gas field well stream typically consists of a majority of gas with some condensate and water. As the reservoir continues to produce over its life time, the composition of the flow will typically change to some extent. Depending on composition and flow direction, multiphase well stream will have different characteristics. Typical flow characteristics for horizontal and vertical flow are shown in Figure 4.5 and Figure 4.6 respectively. As gas to liquid ratio increases, the liquid will disperse into the gas flow as shown for “Spray” in Figure 4.5 and “Annular-Mist Flow” in Figure 4.6 (PetroWiki, n.d.-e).

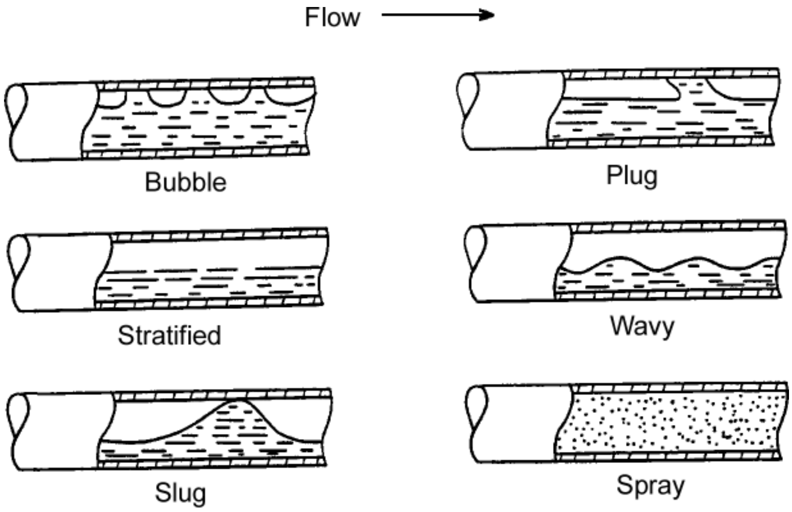


Figure 4.5: Two-phase-flow patterns in horizontal flow (PetroWiki, n.d.-e). Courtesy of AMEC Paragon.

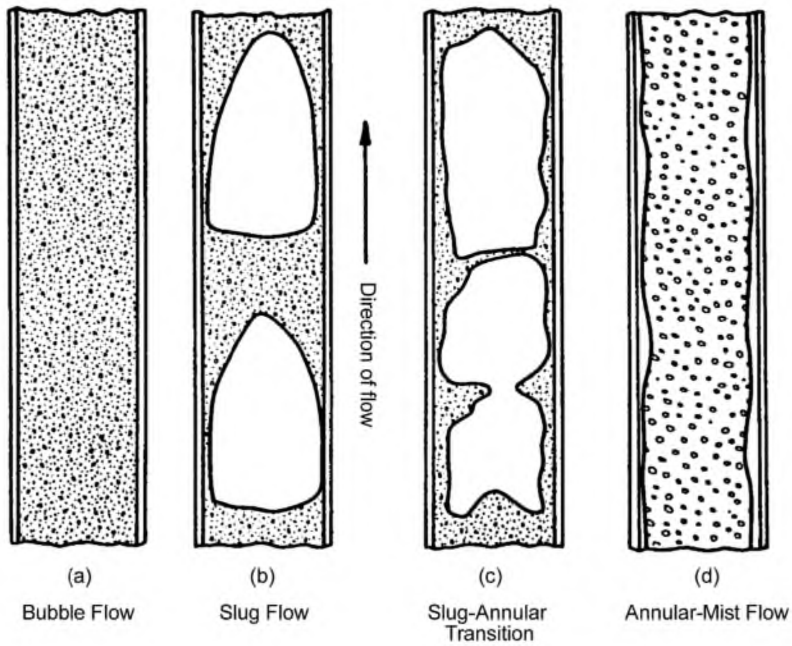


Figure 4.6: Two-phase flow patterns in vertical flow (PetroWiki, n.d.-e). Courtesy of AMEC Paragon.

For the determination of pressure loss in pipelines with multiphase flow a number of flow correlations have been created. These correlations are divided in two categories. One is empirical correlations which are based on experimental data, and the other is mechanistic models based on first principals like conservation of mass and energy. Most of the correlations consider the flow regime to calculate the pressure drops in combination with the liquid hold-up. The liquid hold-up is used to calculate the density of the mixture flowing in the pipelines and is critical for determining the hydrostatic pressure drop. The majority of pressure loss in vertical conduits usually relates to the hydrostatic pressure loss, but in some cases with gas wells producing at very high gas rates the frictional pressure drop can be dominant (Fevang et al., 2012).

A minimum flow will also be required to maintain stable operating conditions for gas dominated multiphase flow, and it is preferable to operate in the friction dominated pressure drop range to maximize flow rate for a corresponding pipeline inlet pressure, illustrated in Figure 4.7. At low flow rates, liquid will start to accumulate in the pipeline and the pressure drop will become gravity dominated. This is typically related to unstable production and slugging conditions (Gyllenhammar et al., 2015).

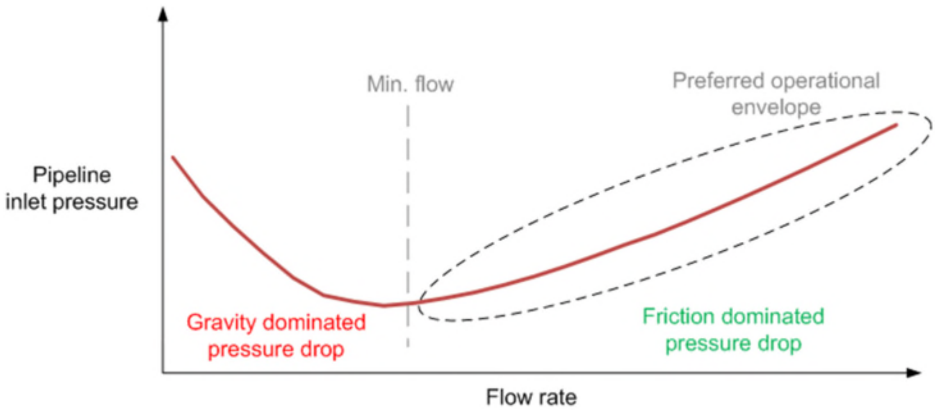


Figure 4.7: A typical pipeline inlet pressure vs. flow rate curve for a multiphase pipeline (Gyllenhammar et al., 2015).

Maintaining a minimum flow is increasingly difficult for long pipelines as the pressure drop increases. Increasing the size of the pipelines is one way to mitigate a high pressure drop, but on the other side it requires a higher minimum flow rate which again restricts the turndown operations (Gyllenhammar et al., 2015). Estimating the actual pressure loss of multiphase flow is a complex task. Phase changes that occur due to pressure and temperature changes along the flow needs to be accounted for, as well as the relative velocity of the phases, and effects of elevation changes (PetroWiki, n.d.-e).

4.4. Accumulated production

When a complete model of the production system has been defined, the production profile and the expected total production volume can be simulated using IPM software. To be able to perform the calculations, the software needs information on the IPR, the VLP and the information on the pipelines and the defined system constraints. The software further needs information on the expected reservoir behavior, where one method is to make use of the material balance concept. The material balance concept is based on conservation of mass, Equation (4.7) (Dake, 1998), and can be used to one-dimensionally model the expected reservoir behavior with time.

$$\text{Mass of Fluids Originally in Place} = \text{Fluids Produced} + \text{Remaining Fluids in Place} \qquad (4.7)$$

Based on the material balance information, the IPR, the VLP and the information on the pipelines and the defined system constraints, the IPM software will make use of a numerically based time-step routine in performing the complete reservoir simulation.

5. Case Definition

For the purpose of comparing the difference in CO_2 emissions between subsea and topside two notional generic gas fields were generated and a realistic production system for both reservoirs was defined. The reservoirs were assigned the case numbers 1 and 2, where the difference was the condensate to gas ratio (CGR) as shown in Table 5.1. The CGR will have an effect on pressure drop and pipeline minimum flow. Other parameters are kept unchanged between the cases. The following section describes the basis of the notional gas fields and the production system.

Table 5.1: Case matrix.

	Subsea Compression	**Topside Compression**
Reservoir 1 – CGR 15	Case 1A	Case 1B
Reservoir 2 – CGR 1	Case 2A	Case 2B

5.1. Reservoir data and well completion

Two reservoirs were created for the analysis with key parameters as specified in Table 5.2. The only change between the two is the CGR. All other reservoir conditions are kept constant. Further details are provided in section 5.5 where set-up of the production system model is described. The reservoirs are specified to be located 1000 meters below the seafloor and the well trajectory for all wells is vertical.

Table 5.2: Reservoir and well data.

	Gas Reservoir 1	Gas Reservoir 2
Original gas in place [BSCF]	5 000	5 000
Reservoir pressure [Barg]	320	320
Reservoir temperature [°C]	56°C	56°C
Reservoir depth [m]	1000	1000
Water depth [m]	2000	2000
Tie-back distance [km]	150	150
Gas specific gravity	0.6	0.6
CGR	15	1
Well depth [m]	1000	1000
Production tubing OD/ID [inches]	5.50/4.77	5.50/4.77

5.2. Field layout and equipment data

5.2.1. Field layout

A subsea production system provides a solution for producing hydrocarbons and consists of a number of components. Figure 5.1 shows a simplified illustration of the field layout for the subsea cases, with a subsea production system with a subsea compression station.

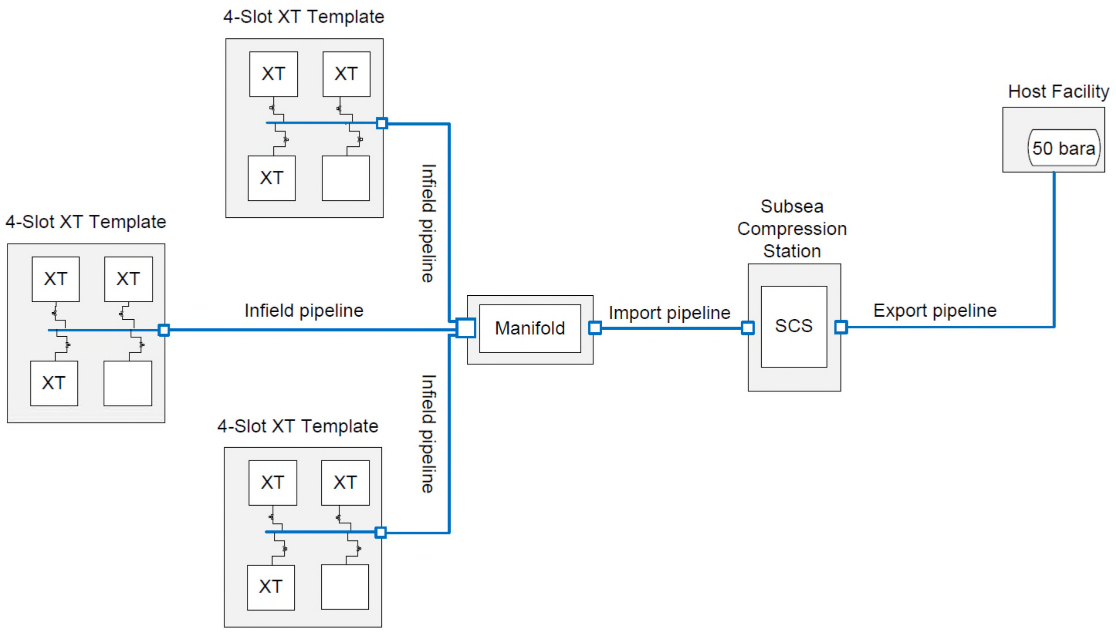


Figure 5.1: Simplified field layout for the subsea compression system cases – Case 1A and Case 2A.

The system configuration is dependent on many variables, and the field layout will be optimized to suit each individual field. One of the main building blocks of the system is the subsea tree (XT). The XTs are installed in a 4-slot template, which acts as protection structure and foundation. There are two main uses of XTs. One is the production XT, which controls the flow from the reservoir to the host. The other is the injection XT, which provides a way to inject water or gas into the reservoir. In production, the flow is routed from the XTs to a manifold through pipelines, and on to the compression station before it is processed and exported to the host. Depending on the location of the subsea compression station relative to the manifold, the connection between the two can be made through an import pipeline or through smaller infield pipelines. Further details on field layout are shown in Table 5.3.

Table 5.3: Field layout information subsea compression.

	Subsea Case 1A	**Subsea Case 2A**
Reservoir	Gas Reservoir 1	Gas Reservoir 2
Subsea trees [qty]	9	9
Compressors [qty]	2	2
Step-out distance [km]	150	150
Water depth compressor station [m]	2000	2000
Export pipelines [qty]	1	1
Export pipeline length [km]	150	150
Export pipeline OD/ID [inches]	24/22	24/22
Import pipelines [qty]	1	1
Import pipeline length [km]	1	1
Import pipeline OD/ID [inches]	22/20	22/20
Infield pipelines [qty]	3	3
Infield pipeline length [km]	7	7
Infield pipeline OD/ID [inches]	12/11.37	12/11.37

Figure 5.2 shows the simplied field layout for the topside cases, with a subsea production system with a topside compression facility. The main difference from the subsea system is that the fluid will need to travel up to and down from the topside facility through risers. In both cases the topside unit is placed directly above the field, where the water depth is 2000 meters. Further details can be found in Table 5.4.

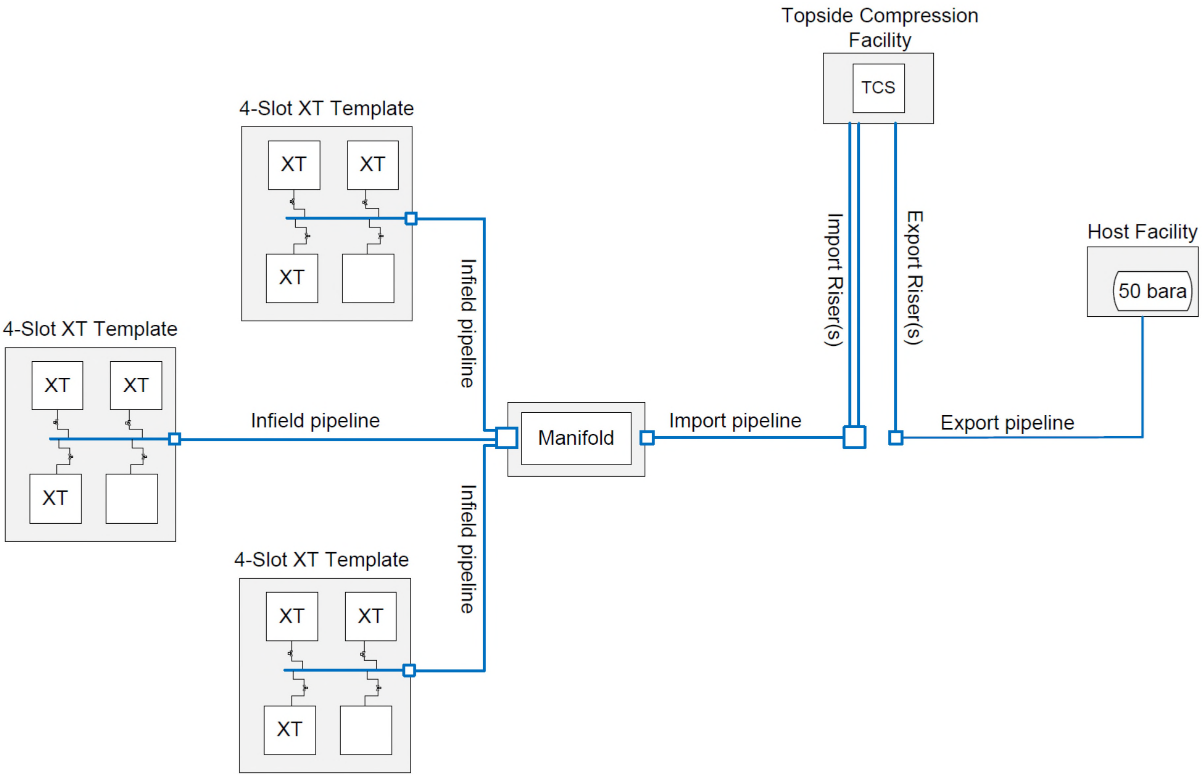


Figure 5.2 Simplified field layout for the topside compression system cases – Case 1B and Case 2B.

Table 5.4: Field layout information topside compression.

	Topside Case 1B	Topside Case 2B
Reservoir	Gas Reservoir 1	Gas Reservoir 2
Subsea trees [qty]	9	9
Compressors	2	2
Water depth compressor platform [m]	2000	2000
Export pipelines [qty]	1	1
Export pipeline length [km]	150	150
Export pipeline OD/ID [inches]	24/22	24/22
Import pipelines [qty]	1	1
Import pipeline length [km]	1	1
Import pipeline OD/ID [inches]	22/20	22/20
Infield pipelines [qty]	3	3
Infield pipeline length [km]	7	7
Infield pipeline OD/ID [inches]	12/11.37	12/11.37
Import risers [qty]	3	3
Import riser length [m]	2000	2000
Import riser OD/ID [inches]	12/10.75	12/10.75
Export risers [qty]	2	2
Export riser length [m]	2000	2000
Export riser OD/ID [inches]	12/10.75	12/10.75

In both cases the production will be routed to a host facility on land through an export pipeline. The main design parameters for the host facility are given in Table 5.5 below and are assumed to be the same for both cases.

Table 5.5: Host facility design parameters.

Maximum production rate [MMSCFD]	600
Minimum arrival pressure [Barg]	50

5.2.2. Compression facilities

For both cases the topside compression system was assumed installed on Aker Solutions' Lean Semi ™ concept. This concept was developed to provide a cost competitive alternative to a conventional topside processing facility. Based on experience data from previous Aker Solutions projects, a configuration for a typical compression platform has been selected. Only the minimum requirements for ancillary systems have been included to keep weight down and to reduce the maintenance requirements. Figure 5.3 provides an illustration of the unit. Table 5.6 provides weight estimates for the topside system. The lean-semi is constructed from two main parts, which are the topside and the hull.

Figure 5.3: Aker Solutions Lean-Semi ™. Courtesy of Aker Solutions.

Table 5.6: Topside compression system weights.

Topside dry weight	**Case 1&2B** [Tonnes]
Equipment	1630
Bulk	1535
Steel	3610
Hull dry weight	
Equipment	673
Bulk	640
Steel	8200
Facility total dry weight	**16 288**

The subsea compressions system was based on Aker Solutions SCS 2.0 dry gas compression concept. The SCS 2.0 concept is an optimization of the system delivered on the Åsgard Subsea Compression System Project, with a focus on decreased weight and size, but keeping core components and functionality. This is mainly achieved through a revised modularization philosophy. Each compressor station is fitted with a 12.0 MW centrifugal compressor. An illustration of the compressor station is shown in Figure 5.4. Table 5.7 provides weight estimates for the subsea system.

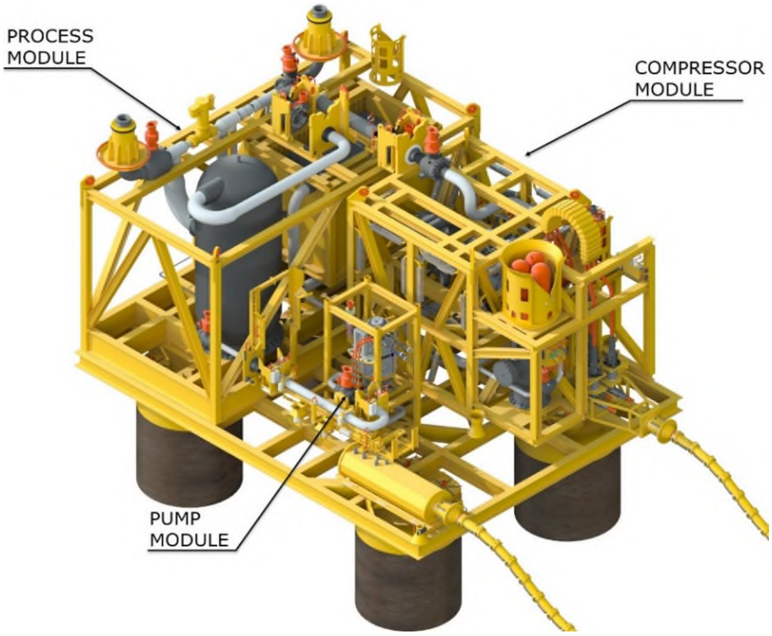


Figure 5.4: Aker Solutions SCS 2.0 compressor station. Courtesy of Aker Solutions.

Table 5.7: Subsea compression system weights.

Subsea compression system	**Case 1&2A** [Tonnes]
Pump module equipment	2 x 14.5
Pump module steel structure	2 x 17.5
Compressor module equipment	2 x 80
Compressor module steel structure	2 x 106
Process module equipment	2 x 129.7
Process module steel structure	2 x 130.3
Foundation steel structure	2 x 144
Subsea compression system total dry weight	**1244**

The same compressor unit was chosen for both the topside and the subsea system. The chosen compressor is a seal-less compressor with magnetic bearings suitable for a dry gas compression system. The implementation of this type of compressor also on the topside facility instead of a more conventional topside compressor, means utility systems such as a seal-gas system and lube-oil systems can be avoided. Fewer utility systems are expected to increase reliability and reduce required maintenance, which are important factors in the simplified lean-semi topside design concept.

5.3. Compression system energy consumption

Compression systems will have an accumulated energy consumption over a lifecycle. The energy consuming activities can be divided in two parts. One part includes all energy required for the one-time activity of getting the system built, installed and decommissioned, and the other part includes all energy required for the continuous operation of the system until the field is abandoned. The one-time energy consuming activities include production of the materials that go into the construction of the system, transportation, manufacturing of the system and the energy required for the installation and decommissioning work. The continuous energy consuming activities include the process compression work, stand-by and support activities, and operation of required ancillary systems such as living quarters, ballast system, cooling systems, heating and ventilation etc. The required activities will vary with type of compression system. As the one-time activities are expected to have low impact on overall emissions when comparing with the continuous energy consumption over a lifecycle, they were not considered as part of this analysis. As an example of how the one-time emissions impact the overall analysis, the energy consumption related to production of the steel for the systems was included, which is probably one of the most energy consuming activities in the construction part of a field development.

5.3.1. Material production - One-time activity

For the topside facility it can be seen from Table 5.6 that most of the weight is directly related to constructional steel. The topside structure is based on trusses made from section beams and pipe, and the hull is mainly made from steel plates. Further, the equipment installed on the unit will mostly be made from the same type of steel products. For the subsea compression system most of the weight is also directly related to the structures, which are mainly fabricated from section beams. The equipment ratio is higher for the subsea unit, but again much of the equipment will be made out a variety of steel products. Life cycle information for production of different types of materials is provided in Table 5.8, and shows that energy consumption related to production of the different steel products is similar. As most of the weight of the topside facility is related to the hull, it was assumed that all weight is attributable to the energy consumption for production of steel plates. For the subsea compression system, it was assumed that all weight is attributable to the energy consumption for production of welded pipes, to account for some materials being more exclusive and requiring a bit more energy in production than the section beams.

Table 5.8: Energy consumption for production of different materials assuming 90% recycling (worldsteel ASSOCIATION, 2018).

Material Type	MJ/Kg	MWh/tonne material
Structural Steel – Sections	16.1	4.47
Structural Steel – Welded Pipe	18.2	5.06
Structural Steel – Plate	16.6	4.61

5.3.2. Operational phase - Continuous activities

Most of the continuous energy consumption in the operational phase will be attributable to the actual process compression work. The power requirement will typically be different for a top side and a subsea system, and the difference will vary a lot with field and project specific variables. The same compressor specifications were considered in the analysis for the cases as shown in Table 5.9.

Table 5.9: Compressor specifications.

	Case 1 (A&B)	Case 2 (A&B)
Compression effect [kW]	24 000	24 000
Pressure ratio limitation	2.65	2.65
Polytropic efficiency [%]	75	75

Given the nature of a subsea compression system being unmanned, many support systems required for a topside system can be avoided. A topside offshore facility will typically require additional ancillary systems related to utility functions and will require living quarters with relating energy requirements for the personnel operating the system. A list of typical utility systems for a topside facility with a seal-less compressor is shown in Table 5.10.

Table 5.10: Typical support systems required on a topside facility.

Topside facility support systems	
Flare gas system	
Fire water system	
Service water system	
Open drain system	
Reclaimed oil sump system	
Compressed air system	
Inert gas system	
Lighting and heating system	
Compressor cooling system	
Combined power requirement	**3 MW**

A topside facility will typically require some stand-by and supply vessels at times, to support the ongoing operations. Further, there will be resources required in relation with transporting personnel to and from the facility for a top side offshore system. However, as the Lean-Semi^{TM} topside concept is developed with a target to reduce manning and required maintenance, and with the development seen in the market targeting more autonomous systems, it was assumed that the contributions in energy consumption from these activities would not be significant for this analysis and they were therefore omitted. For a subsea system, maintenance and repair will be more difficult and energy consuming as intervention vessels will need to be mobilized for these purposes. These contributions were again considered to be very small and insignificant for this analysis and were therefore not included.

5.4. Compression system CO_2 emissions

As for the energy consumption, the CO_2 emissions come from one-time energy consuming activities and continuous activities.

5.4.1. **Material production - One-time activity**

The energy consumption data related to production of the materials have corresponding CO_2 emission data. This information was also provided as part of the information obtained from the World Steel Association and is presented in Table 5.11.

Table 5.11: CO_2 emissions for production of different materials assuming 90% recycling (worldsteel ASSOCIATION, 2018).

Material Type	tonnes CO_2/tonne material
Structural Steel – Sections	1.20
Structural Steel – Welded Pipe	1.34
Structural Steel – Plate	1.27

5.4.2. **Operational phase - Continuous activity**

As emissions are directly associated to energy consumption, the most part of emissions from a compression system will also come from the generation of power to run the compression system. Emissions from power generation can be different from region to region and will depend on the selected power supply solution. For both topside cases it was assumed that the power will be generated by gas turbines installed on the topside facility. According to one study, the average efficiency of gas turbines on the Norwegian continental shelf is approximately 31% (Einang, 2006, cited in KonKraft, 2009). The efficiency of a gas turbine will vary with the load and the selected technology. Based on information obtained from Aker Solutions an average emission factor of 0.66 tonne of CO_2 per megawatt-hour was assumed for the analysis. This seems to be reasonable when comparing with the typical CO_2 emissions expected from a gas turbine, as shown in Figure 5.5 below, given that the turbines will operate within a normal operating window. Gas turbine emissions are likely to be in the same range fairly independent of geographical location, as much of the same technology is available and applied worldwide.

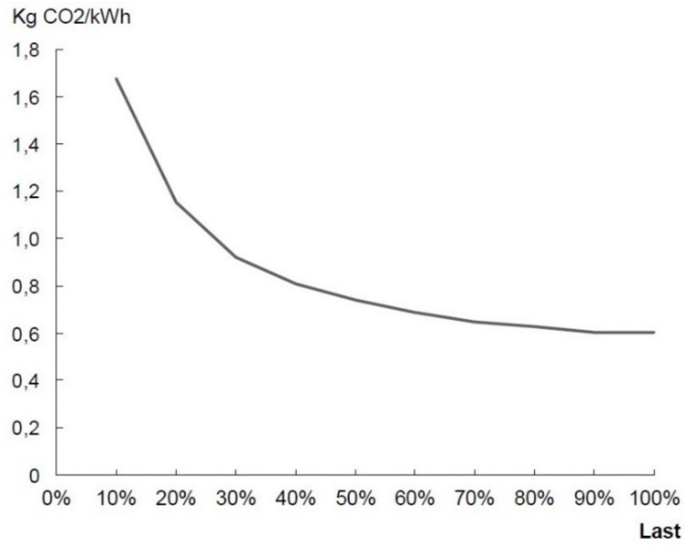


Figure 5.5: Typical CO_2 emissions from a gas turbine as a function of load (Norwegian Petroleum Directorate, 2004, cited in KonKraft, 2009).

For the subsea cases, it was assumed that the power will be supplied from shore through an umbilical. Power production in Norway has very low emissions, as most of the power originates from hydropower plants. As the energy market is open with trade across borders however, it would be relevant to look at emissions related to a Nordic power mix even if the system is installed on the Norwegian continental shelf with power from shore. The IEA estimates the average emissions from power production to be around 0.5 tonne of CO_2 per megawatt-hour on a global level (International Energy Agency, 2018). As the field location is not specified, the average emission factor was used in the calculations for the subsea system. Table 5.12 lists a selection of emission factors for power supply from different sources.

Table 5.12: A selection of CO_2 emissions factors in power production. 1. (The Norwegian Water Resources and Energy Directorate, 2017), 2. (asplan viak, 2016), 3. (International Energy Agency, 2018).

Region/Source	**tonne CO_2/MWh**
Power from generator	0.660
Norwegian power production[1]	0.0164
Nordic power mix[2]	0.130
Average world energy mix[3]	0.500
Power from coal (world)[3]	0.920

5.5. Production system analysis model

As described in section 4, IPM was used to find the missing information required for performing the comparison between the subsea and topside compression systems. The prediction of the production profiles and accumulated volumes for the production system was performed by using software from Petroleum Experts' Integrated Production Modeling Toolkit version 10. The surface gathering network was modelled using the General Allocation Package (GAP), the well models were defined in PROSPER and the reservoir models were defined in MBAL. PROSPER is a well modelling and design program that allows for generation of the IPR and the VLP based on the reservoir, fluid and well characteristics. MBAL is a material balance program that can be used to define reservoir drive mechanisms and hydrocarbon volumes in an easy way, but also features several other applications such as decline curve analysis, Monte Carlo simulations, reservoir allocation and tight reservoir modelling. By linking GAP with well models from PROSPER and reservoir models from MBAL, a full field production optimization and forecast can be achieved by utilizing GAP's built-in optimization engine using non-linear Sequential Quadratic Programming to simulate the multi-phase flow in the production system (Petroleum Experts, 2018).

5.5.1. GAP model

The first step in building the GAP model was defining the global system options. This was done as shown in Figure 5.6.

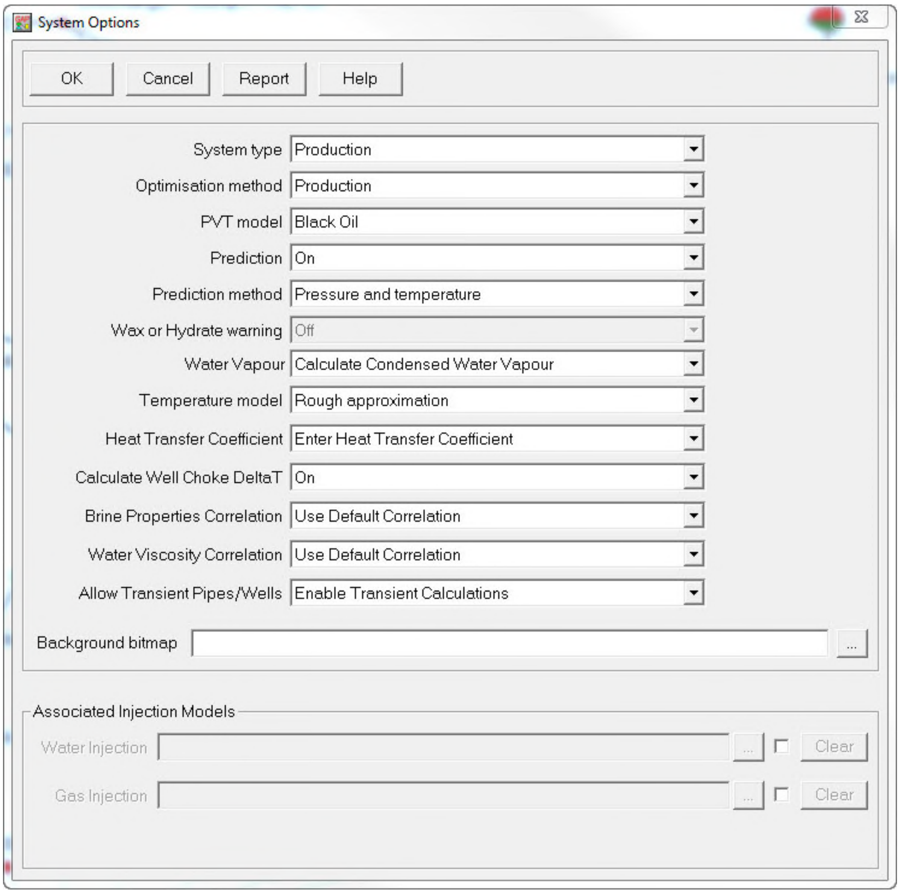
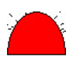
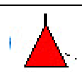
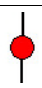
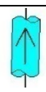
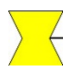
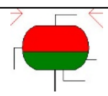


Figure 5.6: GAP global system options.

The model was then established by using some of the predefined objects in the GAP modeling software, shown in Table 5.13. The reservoir is the starting point, to which a number of wells were connected. A separate joint had to be created to represent all the wellhead connections. The joints were then connected by pipe elements that could be given dimensions. Figure 5.7 illustrates the field layout for Case 2A but is identical to Case 1A with the exempt of the gas reservoir. The modelling of the compressor as a well object will be explained in the following section.

Table 5.13: Predefined GAP objects.

Gas Reservoir	Gas Well	Joint	Pipe Element	Choke	Compressor (well)	Separator
						

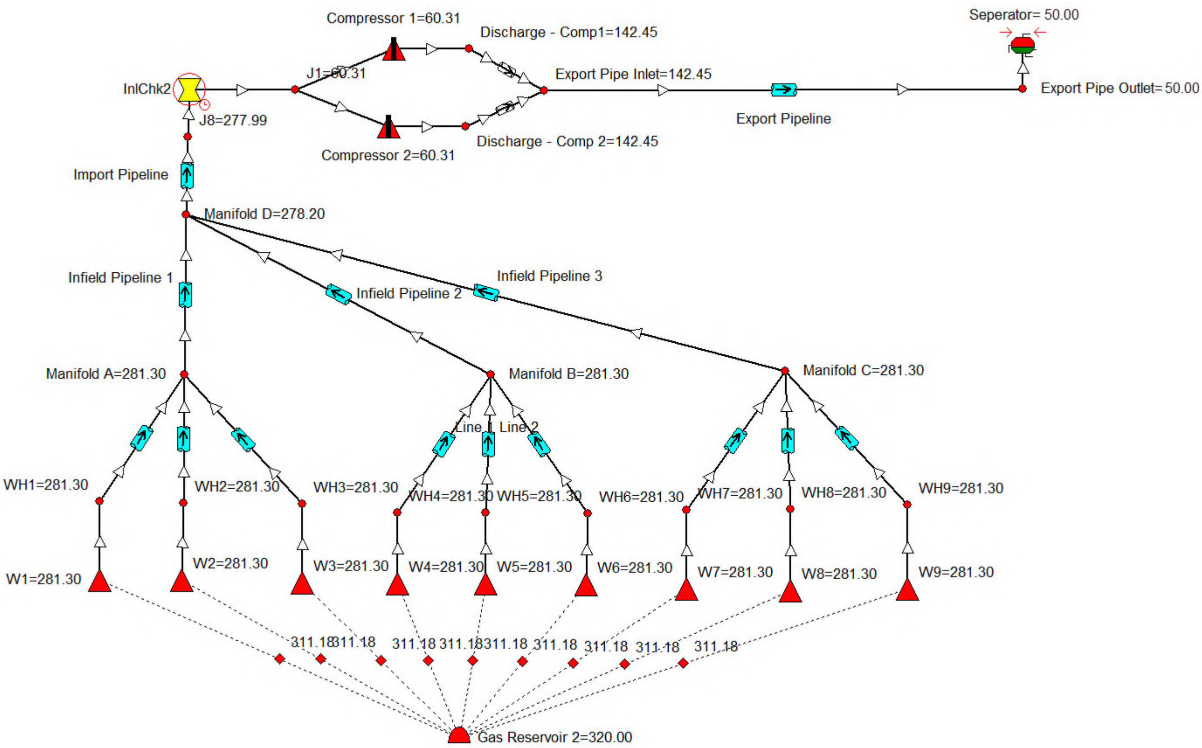


Figure 5.7: Field layout Subsea Case 2A.

The next step was defining the reservoir and the wells. As the reservoir models for the two cases were created in MBAL, the only required action was linking the MBAL reservoir model file for the applicable case to the GAP reservoir object. The well type was defined as “Gas Producer”. The well model was created in PROSPER and was linked to the GAP model well objects. To complete the definition of the wells, the “IPR type” was set to “C and n” in the “IPR” tab sub sheet “IPR Layer” on the “Input” screen, as shown in Figure 5.8. On the “More…” sub sheet on the same tab, the “Prediction Fraction Flow Model” was set to “From Tank Model”. When this was done the IPR and VLP could be created from PROSPER from the main menu, resulting in valid data entry for all sections. As for the reservoir models in MBAL, two different well models were created in PROSPER for the two cases and linked with corresponding GAP model.

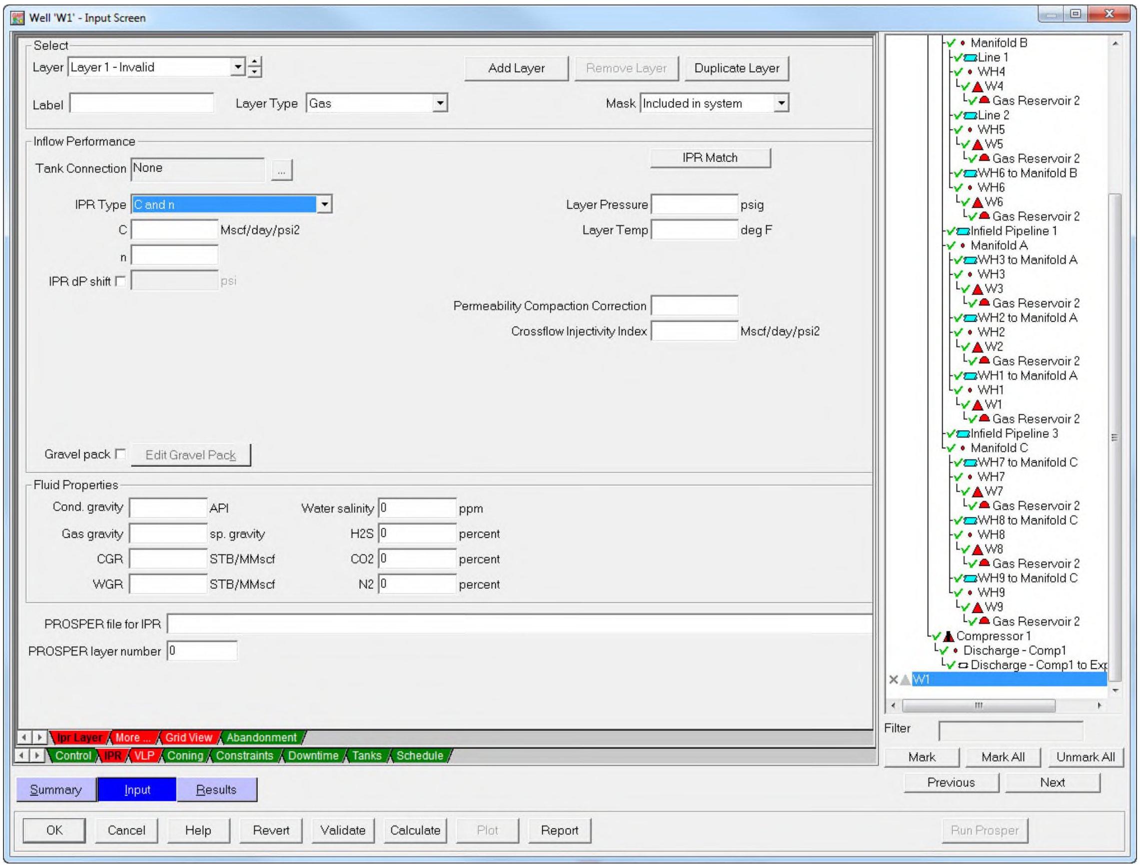


Figure 5.8: Well definition "Input" screen.

The pipe elements were defined according to the field layout details specified in Table 5.3 and Table 5.4. The selected pipe flow correlation was "Petroleum Experts 5" for the horizontal and inclined pipelines, which is a mechanistic model designed to model multiphase mixtures flowing through complex pipeline geometry and which is good for pressure drop calculations. The Petroleum Experts 3 correlation was selected for the risers (Petroleum Experts, 2018).

For the GAP compressor object, the performance curves need to be defined based on the same reference flow rates, with head and power specified for each of the different rotational speeds. The compressor curves available for the compressor used in the present analysis was not available in this format, and was therefore imported as a lift curve and modelled in a well object with "Model" set to "Outflow Only – VLP" as shown in Figure 5.9. The lift curves used in GAP for the compressor were generated in Pipesim 2017.2, using a compressor module with a pressure ratio limitation of 2.6 and a maximum duty of 12 MW.

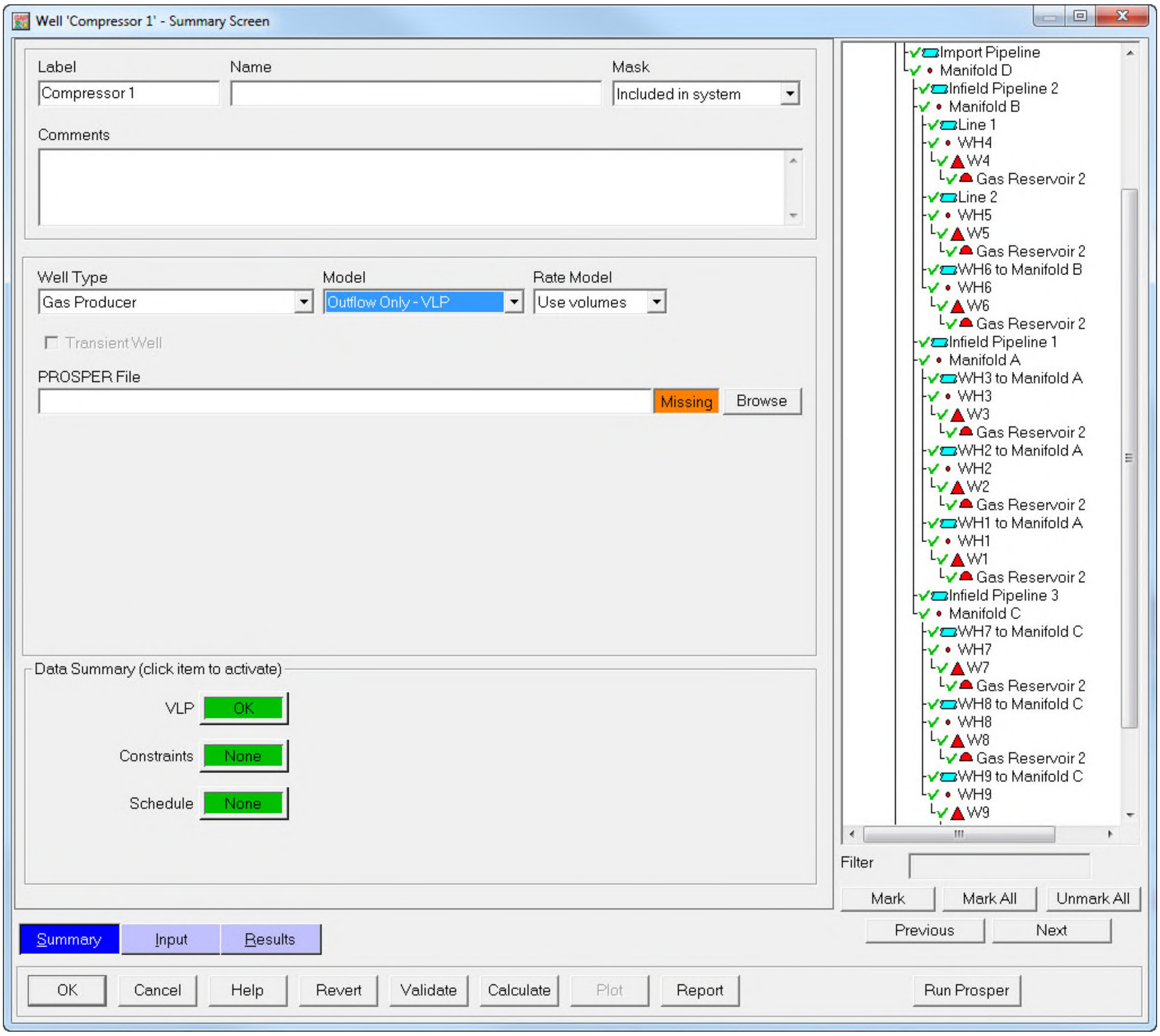


Figure 5.9: Compressor modelled as well object with lift curve.

When the complete production model is defined, predictions can be run from the GAP main menu. GAP will then load the tank model and check that IPR and VLP data are available for each well. Tank pressure and saturations are passed from MBAL to the well models and GAP will solve the network to find the solutions throughout the system. If constraints are specified, the solver will locate the optimum control settings for that timestep, honoring the constraints, to maximize the objective function (Petroleum Experts, 2018). In all cases constraints were added for the maximum gas rate and minimum pressure at the separator, as defined in Table 5.5. An inline choke was modelled to add the control element in the model. The control variable of the inline choke changes from “calculated” to “none” when the reservoir can no longer maintain the plateau rate to reduce calculation time and increase model stability.

5.5.2. MBAL reservoir model

As for the GAP model, the first step in defining the material balance model for the reservoir was to define the global system options. This was done as shown in Figure 5.10. When using the material balance tool in MBAL the reservoir model is based on a tank model and it ignores parameters such as the geometry of reservoir and the position of the wells.

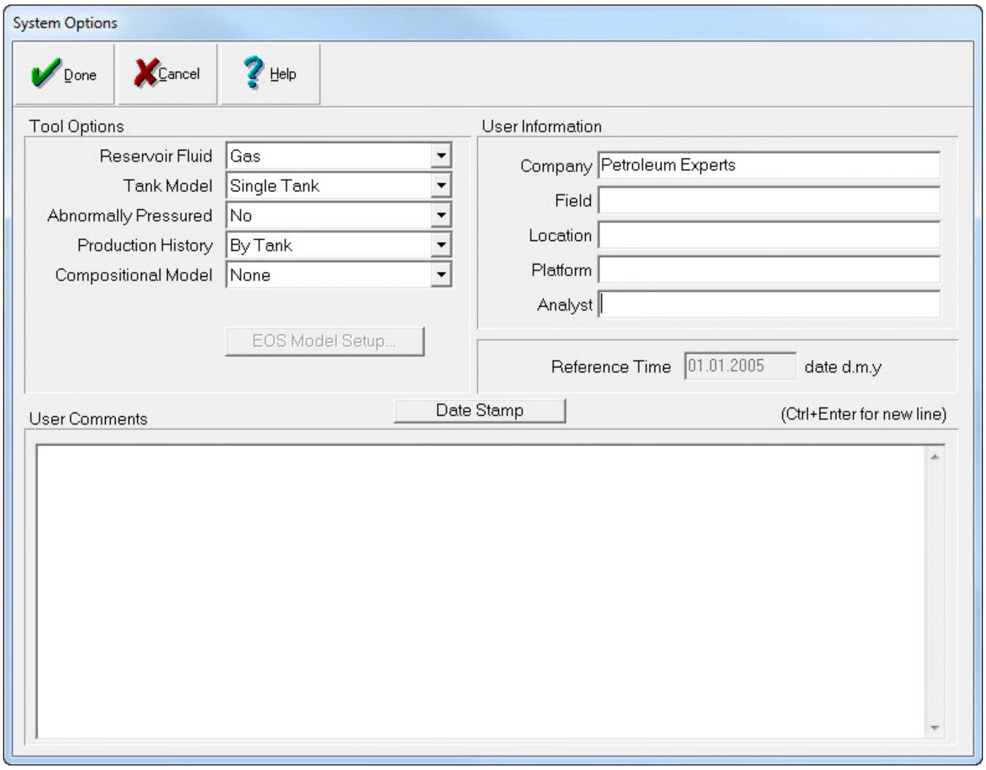


Figure 5.10: MBAL global system options.

The next step was to define the fluid properties. The fluid was defined by entering the black oil fluid properties in the PVT main menu as shown in Figure 5.11. The fluid properties were defined to be the same in the two cases, with an exception of the CGR.

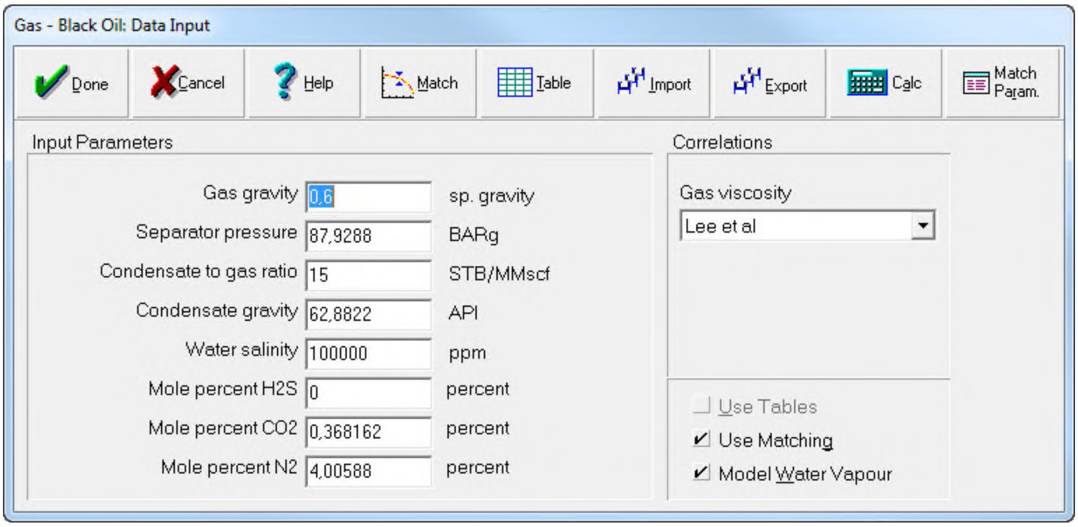


Figure 5.11: PVT properties for Reservoir 1/Case 1.

When the definition of the PVT properties of the fluid was finished, the tank data were specified, with tank parameters as shown in Figure 5.12. Further, the water influx model was set to “none”, as no adjacent aquifer water was assumed present in the analysis. For the rock compressibility the “From Correlation” option was used, which means MBAL will use an internal correlation to evaluate the compressibility based on the specified porosity. The relative permeability was defined from Corey functions.

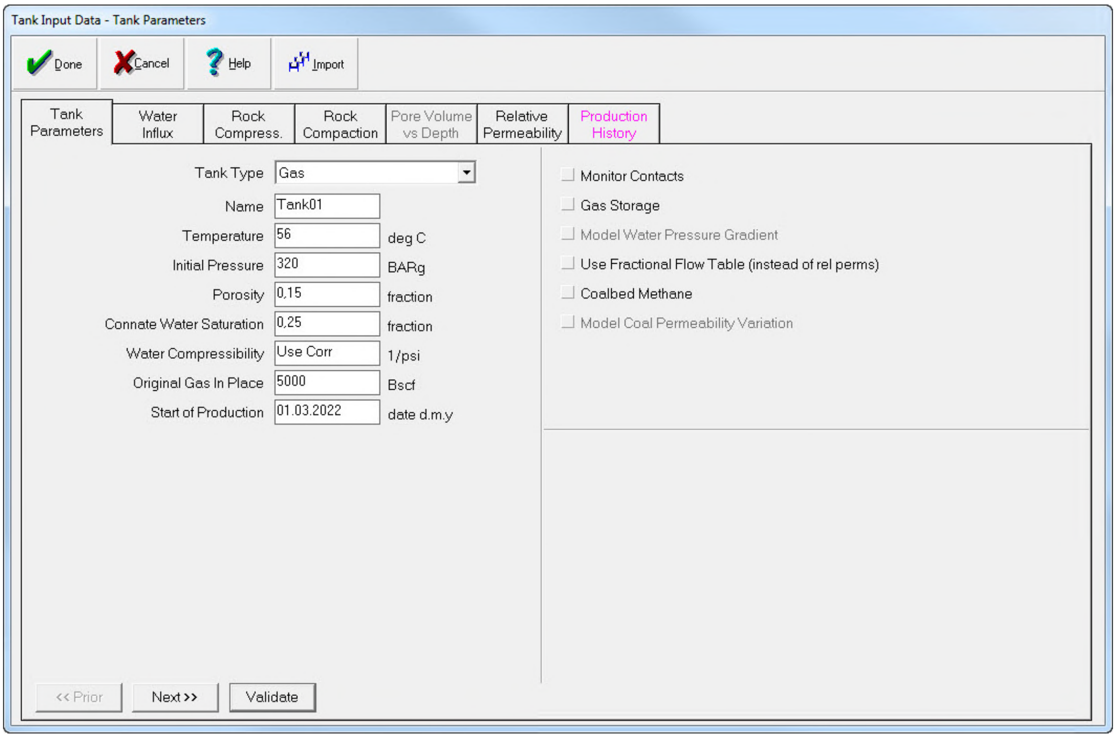


Figure 5.12: Tank parameters.

5.5.3. PROSPER well model

The set-up in PROSPER starts with setting up what type of well that will be modelled. The "Dry and Wet Gas" option was selected and "Black Oil" was selected as method for input of fluid properties. Figure 5.13 shows the system summary for the PROSPER well model. The next step was to define the PVT data, where the same data was input as in the MBAL model.

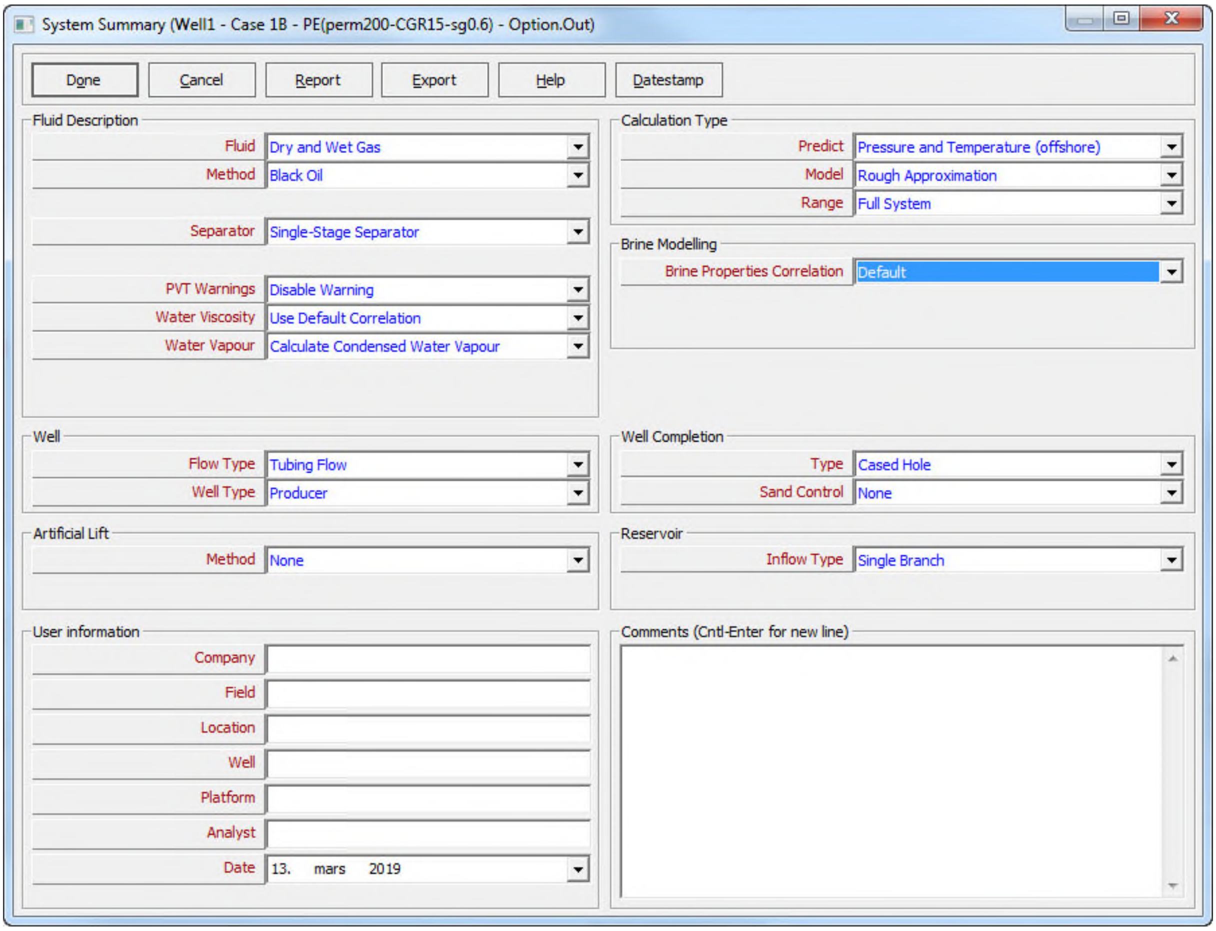


Figure 5.13: System summary for PROSPER well model.

A description of the well is required for PROSPER to calculate the VLP curves for the well. This was specified in the equipment data section. The equipment data section contains several different sub-sections. The different sections were populated as shown in Table 5.14. All wells were assumed to be identical for all cases.

Table 5.14. PROSPER Equipment data section.

Sub-Section	**Input**	**Comment**
Deviation Survey	Measured Depth 1000 m True Vertical Depth 1000 m	Wells assumed vertical
Surface equipment	Not applicable	No surface equipment specified
Downhole Equipment	**Tubing:** Measured depth 900 m True vertical depth 900 m ID: 4.767” **Casing:** Measured depth 1000 m True vertical depth 1000 m ID: 6”	
Geothermal Gradient	15 $W/m^2/K$	
Average Heat Capacitates	C_p Oil: 2.219 KJ/kg/K C_p Gas: 2.135 KJ/kg/K C_p Water: 4.187 KJ/kg/K	
Gauge Details	Not applicable	No gauges specified

Following the input of the equipment data, the IPR section was populated for PROSPER to define how productive the reservoir will be. The “Petroleum Experts” reservoir model which is based on a multi-phase pseudo pressure function was selected to model the well productivity curves. Data were input as shown in Figure 5.14 for Reservoir 2 /Case 2.

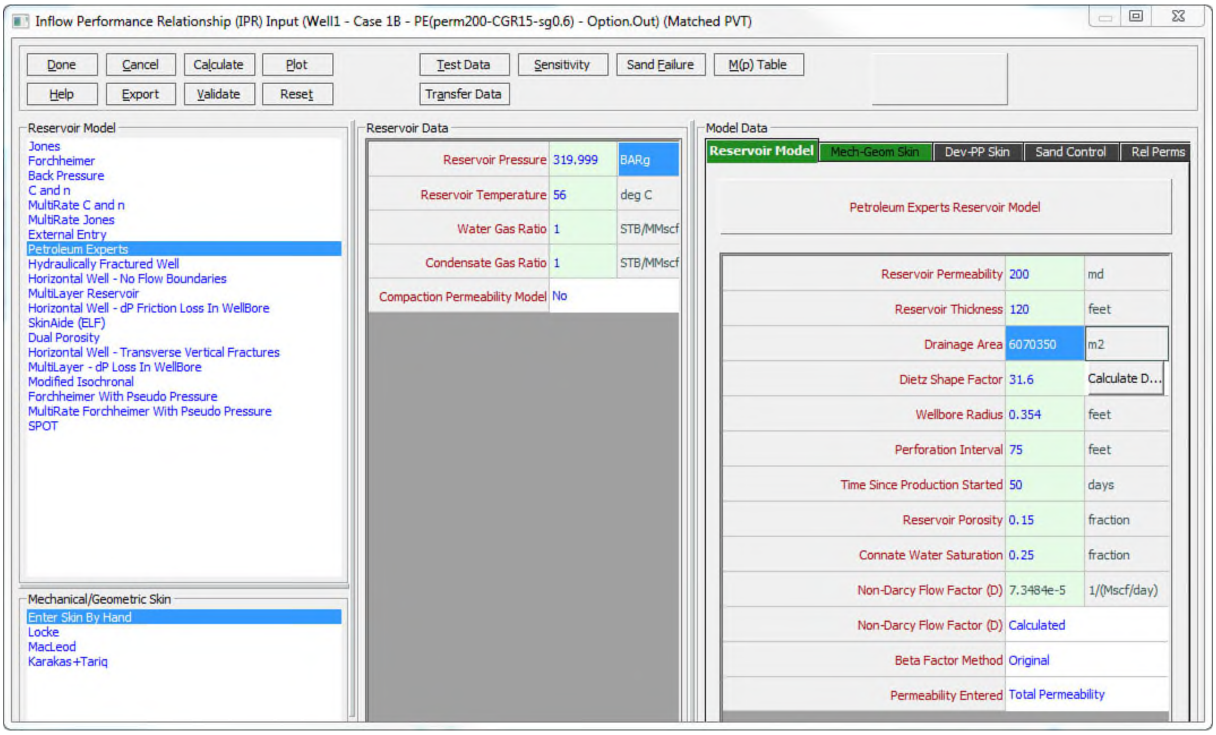


Figure 5.14: Inflow Performance Relationship data summary - Reservoir 2/Case 2.

After all the well data were inserted in PROSPER it was possible to run the system calculations where both the IPR and VLP curves were calculated. As GAP loads the well information from the PROSPER file it is essential that the VLP and IPR data represent a wide enough range of conditions so that the true behavior of the well can be captured. If the values calculated in GAP falls outside of the defined range, GAP will extrapolate to find a solution, but this can result in errors (Petroleum Experts, 2018).

5.6. Analysis summary

To be able to compare the results between the subsea and topside compression systems the main target is to find the difference in kilos of CO_2 emitted per BOE produced. By utilizing the information in the previous sections to define the GAP model, predictions could be run to find the required information. The GAP model only predicts the energy consumption related to the compression work, and hence only captures the associated emissions for power generation. In addition, the emissions from production of the materials for the systems and the emissions from power generation for the topside support systems need to be considered to get the complete picture. In calculation of the emissions from the topside support systems the operational lifecycle is required. This is an output from the GAP predictions. The emissions from the material production can be calculated based on the defined weights and the emission factors associated to steel production. The total emissions for the systems will therefore consist of the factors described in Table 5.15. When the total emissions are found, they must be divided by the accumulated production volumes for the two systems to find the emissions per BOE which are used for benchmarking. The accumulated production volume is also an output from the GAP predictions.

Table 5.15: Total emissions.

	Subsea	**Topside**
Integrated Production Modeling Results (GAP)		
Energy consumption and emissions from compression work	*Yes*	*Yes*
Additional energy consumption and emissions		
Energy consumption and emissions in material production	*Yes*	*Yes*
Energy consumption and emissions from topside support systems	*Not applicable*	*Yes*

When running the prediction in GAP, the prediction run was set up to run with three-month time-steps for a period of 30 years as that turned out to cover the complete lifecycle for both systems in both cases. A summary of selected information for the two cases are included in Table 5.16.

Table 5.16: Comparison cases.

	Case 1		**Case 2**	
	1A (Subsea)	1B (Topside)	2A (Subsea)	2B (Topside)
Original gas in place [BSCF]	5000	5000	5000	5000
CGR	15	15	1	1
Water depth [m]	2000	2000	2000	2000
Export pipeline length [km]	150	150	150	150
Maximum flow rate @ host [MMSCFD]	600	600	600	600
Minimum host arrival pressure [Barg]	50	50	50	50

6. Results

6.1. Integrated production modelling results

6.1.1. Subsea Case 1A and Topside Case 1B

After running the predictions in GAP, the results show that the accumulated energy consumption of the compressors is approximately 17% lower for the subsea system over the lifecycle. This leads to approximately 38% lower CO_2 emissions per BOE produced. The reservoir pressure at the abandon date is slightly lower in the subsea system, resulting in a higher accumulated production volume. Based on Equinor's internal gas price for Q1 2019, the additional volume constitutes approximately 2.13 billion NOK. For the subsea compression system, the operational lifecycle is 23 years. The topside compression system will produce for an additional 9 months after the abandon date for the subsea system. Some key results from the predictions are shown in Table 6.1.

Table 6.1: Prediction results from GAP for Subsea Case 1A and Topside Case 1B.

	Subsea Case 1A	**Topside Case 1B**	**Subsea vs Topside**
Production start date	01.03.2022	01.03.2022	
Compression start date	01.03.2031	01.12.2028	
End of plateau date	01.09.2035	01.06.2034	
Abandon date	01.03.2045	01.12.2045	
Reservoir pressure @ abandonment [Barg]	50.0	52.4	- 4.6%
Accumulated production volume [BSCF]	4 193.10	4 152.50	1.0%
Accumulated energy consumption compression work [GWh]	1 725.55	2 068.41	- 16.6%
Accumulated CO_2 emissions compression work [kt]	862.78	1 365.15	- 36.8%
CO_2 emissions related to power supply for compression work over lifecycle [kgCO_2/BOE]	1.19	1.91	- 37.7%

Figure 6.1 illustrates how the flow rates and the accumulated production volumes evolve for the two systems over the lifecycle.

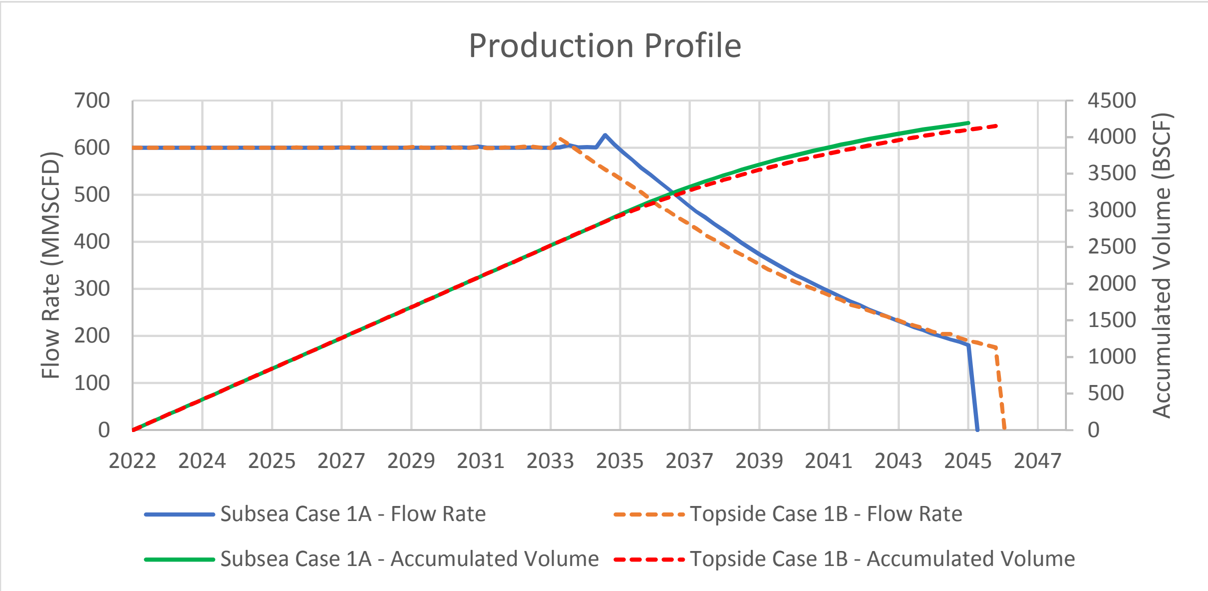


Figure 6.1: Production profile - Case 1A vs Case 1B.

As long as the plateau rate is maintained the accumulated volumes stay close to identical. The subsea system will be able to extend plateau production with an additional 15 months compared with the topside system. When the plateau rate can no longer be maintained by the topside compression system and the flow rate starts to fall, the accumulated volume increases more rapidly for the subsea system due to the continued operation at a higher flow rate. The reason the topside system drops off plateau earlier is that the total pressure drop in the system will be higher, as the production will need to flow up and down through the risers. Flowing up and down the risers will mean additional pressure drop, where the frictional component is the main contributor. The lower pressure drop allows the subsea system to deliver the plateau rate at a lower flowing wellhead pressure and maintain higher flowrates for a longer time, resulting in an accelerated production lifecycle.

Figure 6.2 shows how the power demand and accumulated energy consumption develops over the lifecycle for the two systems.

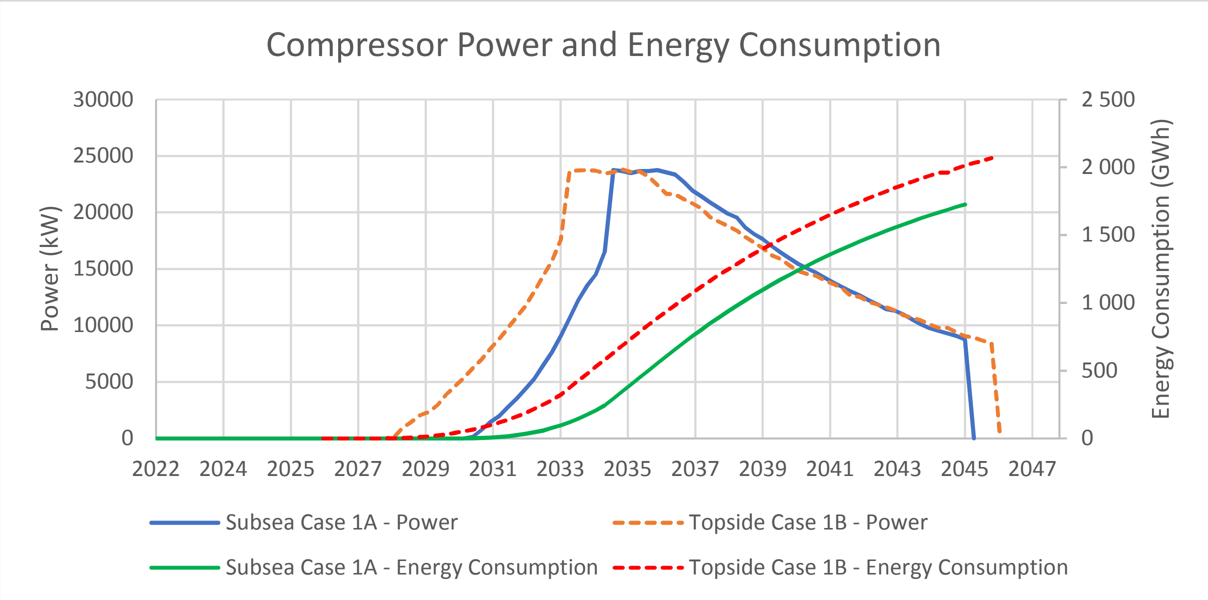


Figure 6.2: Compressor power and energy consumption - Case 1A vs Case 1B.

Looking at the figure in conjunction with Figure 6.1 shows the compressors in the topside system hitting the power limit at the point where the plateau rate can no longer be maintained. The same is the case for the subsea compressors. Maintaining the plateau rate involves meeting a minimum inlet pressure in the export pipeline at the given rate. Up until the point when that can no longer be achieved, the compressors have been able to compensate for the falling inlet pressure by increasing the power. When the inlet pressure drops to a level where the compressors can no longer meet the minimum export pipeline inlet pressure at the plateau rate, the flow rate will start to decrease. Further it can be observed from Figure 6.2 that the compressors will continue to operate at maximum power before the power starts to drop off. This is because the compressors were limited by power and not pressure ratio when going off the plateau. When lowering the flow rate, the pressure drop in the reservoir inflow, the well, risers and pipelines decrease. This compensates for the reduction in reservoir pressure when going off plateau. The compressor will still be able to operate at its full duty, with a gradually lower flow rate and higher pressure ratio, until the maximum pressure ratio limitation of the machine is met. When the pressure limitation is reached, the compressor will no longer be able to utilize the full power availability.

By using the correlations between power generation and CO_2 emissions as defined in Table 5.12, the CO_2 emissions related to power supply for the compression work can be plotted as shown in Figure 6.3. The figure illustrates the emissions of CO_2 per BOE as a function of time both for the individual time-steps and for the accumulated volume as the lifecycle progresses. It also shows the energy consumption per BOE in the time-steps.

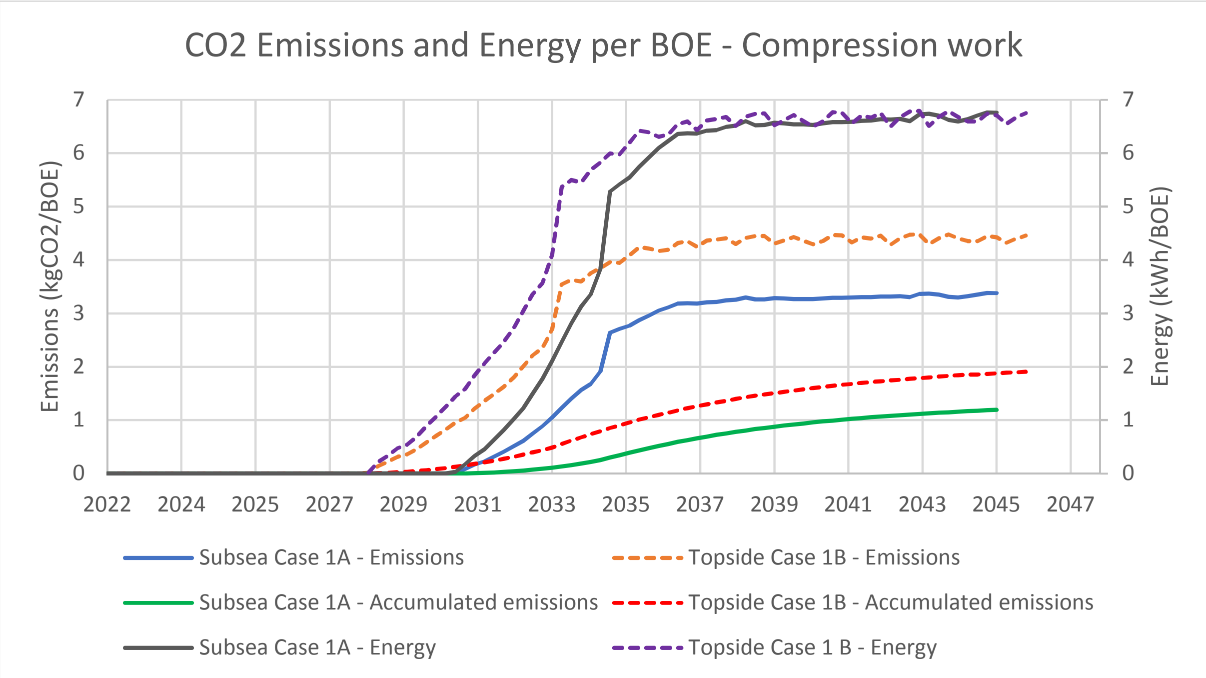


Figure 6.3: CO_2 Emissions and energy per BOE - Case 1A vs Case 1B.

The emissions will be zero as long as the reservoir can produce the plateau rate without pressure support when looking isolated at the GAP predictions. When the reservoir can no longer maintain the plateau rate by natural drive, the compressors will start consuming energy. Looking at Figure 6.3 in conjunction with Figure 6.2 shows that the emissions per BOE rise quickly as the compressors approach full power, before they again stabilize when the flow rates and power consumption drop towards abandonment. From this it can be observed that much of the difference in emissions for the two systems is from the period where the subsea system is able to maintain the same flow rates as the topside system, with a much lower power consumption due to the difference in system pressure drop. As the flow rate decreases, the frictional pressure-drop becomes less significant and the difference in time-step energy consumption per BOE between the two systems converge. The time-step CO_2

emissions stay different due to the difference in emission factors for power supply between the two systems. The accumulated CO_2 emissions per BOE is a function of the total produced volume up until a given point in time and will also be zero until compression starts. This relationship will start increasing slowly before it will accelerate as the accumulated volumes including compression starts to become more significant. Figure 6.3 can be a bit misleading as it indicates that the accumulated emissions per BOE seems to flatten out from 2039, but this can be explained by the decreasing accumulated volume in each three-month time-step as the flow rate declines from plateau. Figure 6.4 illustrates the emissions as function of accumulated volume and clearly shows that the accumulated emissions continue to increase steadily towards the abandon date.

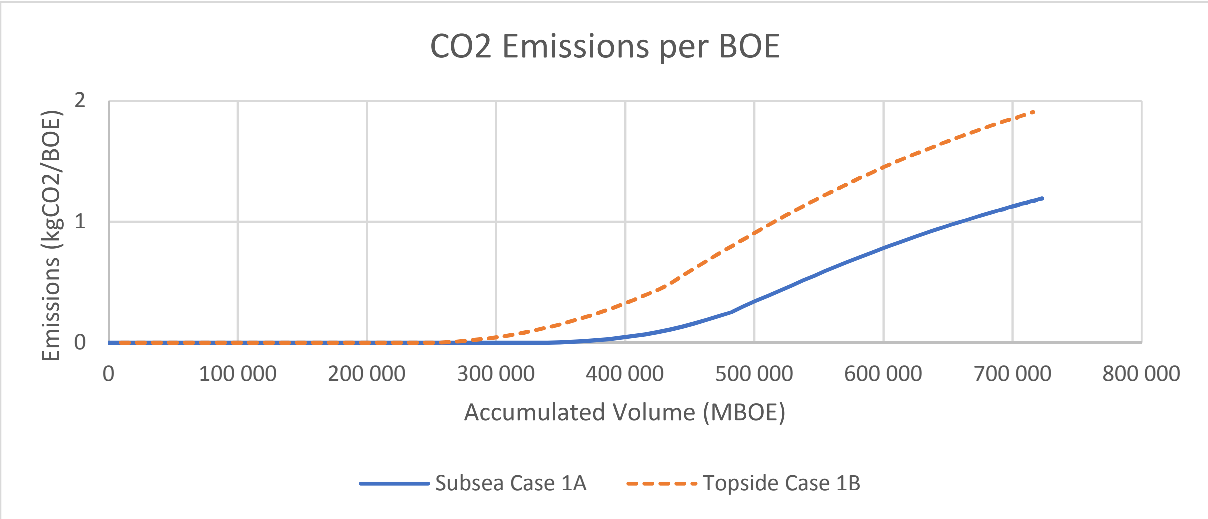


Figure 6.4: CO_2 Emissions as a function of accumulated volume.

6.1.2. Subsea Case 2A and Topside Case 2B

From the results in Table 6.2 it can be observed that the overall energy consumption and accumulated CO_2 emissions drop over the lifecycle compared with the results in Case 1. The energy consumption of the subsea compressors is still approximately 17% lower than that of the topside compressors, and the average CO_2 emissions per BOE is approximately 37% lower over the lifecycle. The reservoir pressures are slightly lower at the abandon date for both systems when comparing with Case 1, meaning more volumes are extracted from the reservoirs. In Case 2 the additional volume from the subsea system constitutes approximately 1.71 billion NOK of additional revenue. Further it can be noticed that the abandon date is the same in Case 2 as it was in Case 1 for both systems, but that plateau production is extended with three months for the subsea system and with six months for the topside system. All these observations come as a result of a lower system pressure drop, due to the lower CGR. The lower CGR means there will be less liquid in the system, and this affects the gravity gradient in the pressure loss calculations. A detailed review of the trends shown in the figures for Case 1 was also performed for Case 2. The review shows there are no significant changes to any of the trends observed for Case 1, outside what is already commented. Only the main prediction results in Table 6.2 are included in this section. The remaining figures are included in Appendix A.

Table 6.2: Prediction results from GAP for Subsea Case 2A and Topside Case 2B.

	Subsea Case 2A	Topside Case 2B	Subsea vs Topside
Production start date	01.03.2022	01.03.2022	
Compression start date	01.12.2031	01.06.2029	
End of plateau date	01.12.2035	01.12.2034	
Abandon date	01.03.2045	01.12.2045	
Reservoir pressure @ abandon [Barg]	47.8	49.7	- 3.8%
Accumulated production volume [BSCF]	4 230.43	4 197.20	0.8%
Accumulated energy consumption compression work [GWh]	1 647.31	1 978.04	- 16.7%
Accumulated CO_2 emissions compression work [kt]	823.65	1 305.51	- 36.9%
CO_2 emissions related to power supply for compression work over lifecycle [$kgCO_2/BOE$]	1.13	1.80	- 37.2%

6.2. Additional energy consumption and emissions

6.2.1. Energy consumption and emissions in material production

The energy consumption related to the material production was calculated by using the correlations defined in Table 5.8 and the weights for the different systems as defined in Table 5.6 and Table 5.7. By further utilizing the correlation obtained from World Steel Association between material production and emissions as defined in Table 5.11, the CO_2 emissions were calculated. The results are shown in Table 6.3.

Table 6.3: Energy consumption in raw material production.

	Subsea Case 1A and 2A (SCS 2.0)	Topside Case 2A and 2B (Lean-Semi)
Energy consumption [GWh]	6.29	65.08
CO_2 emissions [kt]	1.67	17.92

6.2.2. Energy consumption and emissions for topside support systems

As the predictions in GAP did not consider the power required for the support systems for the top side facility over the lifecycle, this was calculated separately. This power demand was assumed to be constant over the lifetime and the accumulated consumption was calculated based on the operational lifecycle of each case. As the operational lifecycle for the two topside cases turned out to be the same from the predictions, the energy consumption was identical. Again, the correlation between power generation and CO_2 emissions for gas turbines as defined in Table 5.12 was used to convert consumed energy into emissions.

Table 6.4: Energy consumption and CO_2 emissions for topside facility support systems over lifecycle.

	Topside Case 1B	Topside Case 2B
Energy consumption [GWh]	624.67	624.67
CO_2 emissions [kt]	412.28	412.28

6.3. Total energy consumption and emissions

When the emissions from the compression work from the GAP prediction is combined with the additional emissions from material production and the topside support systems, the total emissions per BOE can be found for the two cases.

6.3.1. Subsea Case 1A and Topside Case 1B

There was a clear difference in energy consumption and emissions when only looking at the compression work from the GAP predictions between the two systems. The results in Table 6.6 further show that the continuous power consumption of the support systems on the topside facility will also be significant. This constitutes approximately 23% of the total energy consumption of the topside system over the lifecycle. The total energy consumption of the subsea system is approximately 37% lower than that of the topside system. Of the additional energy consumed by the topside system, approximately 33% is linked to the compression work and 61% to the topside support systems. This shows that most of the difference in energy consumption between the two systems is actually due to the support systems required for the topside compression system.

Table 6.5: Total energy consumption over lifecycle for Subsea Case 1A and Topside Case 1B.

	Subsea Case 1A	**Topside Case 1B**	**Subsea vs Topside**
Energy consumption of compressors over lifecycle [GWh]	1 725.55	2 068.41	
Energy consumption in material production [GWh]	6.29	65.08	
Energy consumption of topside support systems over lifecycle [GWh]	0	624.67	
Total energy consumption over lifecycle [GWh]	**1 731.84**	**2 758.16**	**- 37.2%**

The results in Table 6.6 show that the total emissions per BOE from the subsea system is approximately 53% lower than from the topside system. Of the additional emissions from the topside system, approximately 55% is linked to the compression work and 44% to the topside support systems. It can now be observed that the main difference in emissions between the two systems is accountable to the compression work and not the topside support systems as was the case for the energy consumption. This is because of the emission factor used in the conversion, where the subsea system uses the emission factor for average emissions from shore power while the topside system uses the emission factor for power generation with gas turbines. Further, the results show that the impact of including the emissions from the material production is negligible for the subsea system and minor for the topside system.

Table 6.6: Total emissions over lifecycle for Subsea Case 1A and Topside Case 1B.

	Subsea Case 1A	Topside Case 1B	Subsea vs Topside
CO_2 emissions related to power supply for compression work over lifecycle [$kgCO_2$/BOE]	1.19	1.91	
CO_2 emissions related to material production split over lifecycle [$kgCO_2$/BOE]	0.002	0.02	
CO_2 emissions related to power supply for support systems over lifecycle [$kgCO_2$/BOE]	0	0.58	
Total emissions over lifecycle [$kgCO_2$/BOE]	**1.19**	**2.51**	**- 52.6%**

When looking at the total accumulated emissions as a function of time as shown in Figure 6.5, the inclusion of the material production emissions become visible at the start of the graph for the accumulated data series, as the emissions will be divided on a very limited accumulated production at that point. As the field continue to produce, the emissions will be split on a larger accumulated volume and the emissions per BOE will drop off. The inclusion of the continuous consumption of the topside support systems keeps the accumulated emissions from falling below a certain value. As long as the plateau rate can be maintained, the relationship between emissions and accumulated volume will be stable as the energy consumption is the same. This is no longer valid when the compression work starts.

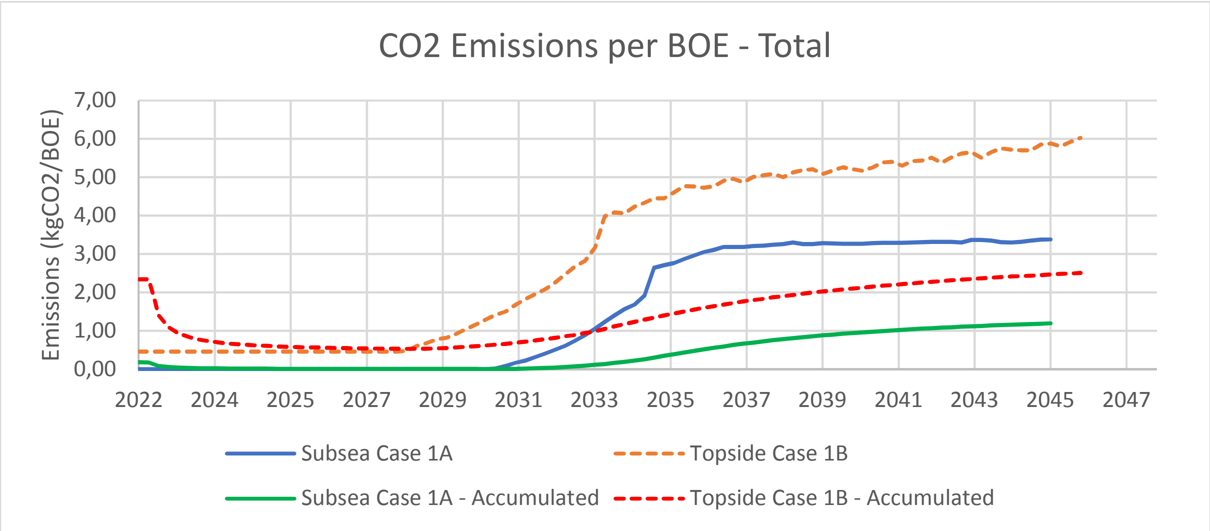


Figure 6.5: Total emissions over lifecycle for Subsea Case 1A and Topside Case 1B.

The results from the CO_2 analysis show that the total accumulated CO_2 emissions per BOE will increase with time both for a topside and a subsea solution. This is because additional energy will be required to maintain production as the reservoir pressure declines. With the addition of the emissions from the continuous power consumption of the topside support systems, it is clear from Figure 6.5 that the difference between the systems will only increase with time.

6.3.2. Subsea Case 2A and Topside Case 2B

When comparing the total energy consumption in Case 2 with the results from Case 1, it can be observed that the total emissions go down for both systems. This comes as a result of a change in the power consumption of the compressors due to the lower liquid content in the production flow as described in section 6.1.2. As pointed out in section 6.2 there are no changes in the additional energy consumption and emissions between the cases. It is worth noting that the lower energy consumption of the compressors over the lifecycle, means that the CO_2 emissions from the topside support systems become slightly more significant in the total, as they are the same in Case 2B as in Case 1B. The total energy consumption of the subsea system is approximately 38% lower than that of the topside system in Case 2. Looking into the additional energy consumption of the topside system shows that approximately 33% is linked to the compression work and 62% to the topside support systems.

Table 6.7: Total energy consumption over lifecycle for Subsea Case 2A and Topside Case 2B.

	Subsea Case 2A	**Topside Case 2B**	**Subsea vs Topside**
Energy consumption of compressors over lifecycle [GWh]	1 647.31	1 978.04	
Energy consumption in material production [GWh]	6.29	65.08	
Energy consumption of topside support systems over lifecycle [GWh]	0	624.67	
Total energy consumption over lifecycle [GWh]	**1 653.60**	**2 667.79**	**- 38.0%**

The results in Table 6.8 show that the total emissions per BOE from the subsea system is again approximately 53% lower than from the topside system. Of the additional emissions from the topside system, approximately 53% is now linked to the compression work and 46% to the topside support systems. Again, it can be observed that the different emission factors cause a shift such that the compression work become dominant when considering the difference in CO_2 emissions between the systems.

Table 6.8: Total emissions over lifecycle for Subsea Case 2A and Topside Case 2B.

	Subsea Case 2A	**Topside Case 2B**	**Subsea vs Topside**
CO_2 emissions related to power supply for compression work over lifecycle [kgCO_2/BOE]	1.13	1.80	
CO_2 emissions related to material production split over lifecycle [kgCO_2/BOE]	0.002	0.02	
CO_2 emissions related to power supply for support systems over lifecycle [kgCO_2/BOE]	0	0.58	
Total emissions over lifecycle [kgCO_2/BOE]	**1.13**	**2.40**	**- 52.9%**

7. Discussion

7.1. Creation of analysis cases

The ambitions were intentionally set high with regards to creating many different cases for the analysis work, to study how different variables affected the results. During the work with the GAP predictions however, it quickly became clear that the number of cases had to be limited. Setting up the production system model in GAP, the well model in PROSPER and the reservoir model in MBAL has been a challenging task. A lot of time has been spent running predictions and reading user manuals to get the model set up to run correctly and to fully understand the importance of the different input parameters. The solver iterations in GAP are complex, and understanding why some predictions end up giving very different results based on small input changes has not been easy. The fact that each prediction requires a lot of computational power and can take several hours of calculation time to solve limited the ability to quickly test how different input parameters changes the overall results. Time was also spent trying to figure out how to model the compressors, as the format of the compressor curves were not compatible with the GAP compressor module. Understanding how the full interaction between the three software tools worked was also a bit challenging.

7.1.1. Pipe flow correlations for multiphase flow

One of the uncertainties related to creating a production system model to make predictions concerns the selection of flow correlations used for calculating pressure drop of multiphase fluid flow through pipelines. A variety of flow correlations exist and there is typically no easy way to be certain to which will give the most reliable results for the specific model, without matching actual field test data with results obtained from the pressure loss predictions. As many of the experiments used as basis for creating different empirical lab correlations were performed at lab scale with small equipment, pipe diameter and length will also be a factor creating uncertainty. The production system model consists of both vertical, horizontal and inclined pipelines, where the main difference between the topside system and the subsea system is that the topside system requires risers to transport the fluids up and down from the platform facility. As a result, it was especially important to select the appropriate flow correlation for calculating the pressure drop in the import and export risers.

According to Fevang et al. (2012), which studied the accuracy of known vertical lift model correlations with data from about 80 production tests on Statfjord, the Petroleum Experts 3 (Petroleum Experts, 2018) and the Hagedorn and Brown (Hagedorn & Brown, 1965), correlations seemed to give the best predictions at high gas to liquid ratios. Another study was performed by Moniem and El-Banbi (2015) where they analyzed a database composed of 3200 measured pressure points from 879 wells with a wide variety of flow conditions. The results indicated that for any flow in a vertical tubular, for a fluid with properties matching those of the fluid used in this thesis, the Mukherjee and Brill (Mukherjee & Brill, 1999) and Beggs and Brill (Beggs & Brill, 1973) correlation gave the best results. The mentioned studies were conducted to identify the best flow correlations for vertical flow in production tubing, but the conclusions should be transferable to vertical risers which will have the same geometry. Further, the GAP user manual also identifies the Petroleum Experts 3 correlation as suitable for vertical flow (Petroleum Experts, 2018). A comparison of the pressure drop results obtained from GAP when using the Petroleum Experts 3 correlation and the Mukherjee and Brill correlation was performed for Topside Case 2B. The comparison showed that the predictions correlated well between the different models for the platform import risers. The Petroleum Experts 3 model predicted a slightly higher pressure drop consistently over the lifecycle as shown in Figure 7.1. The results for the platform export risers again show good alignment between the models from the start of the lifecycle. In approximately 2035 the models deviate more significantly as shown in Figure 7.2.

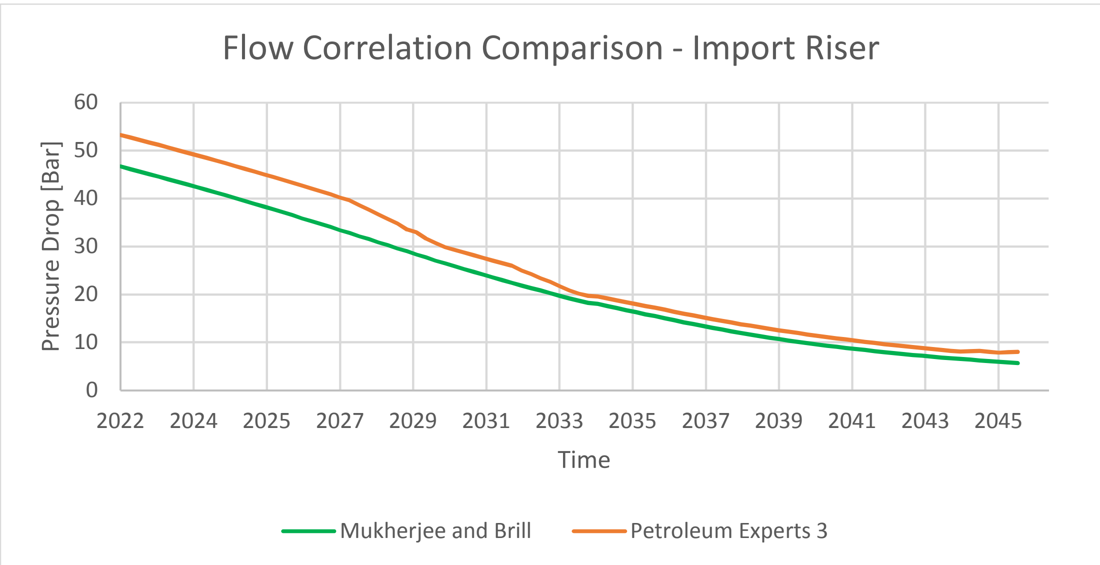


Figure 7.1: Flow correlation pressure drop comparison - Import riser - Topside Case 2B.

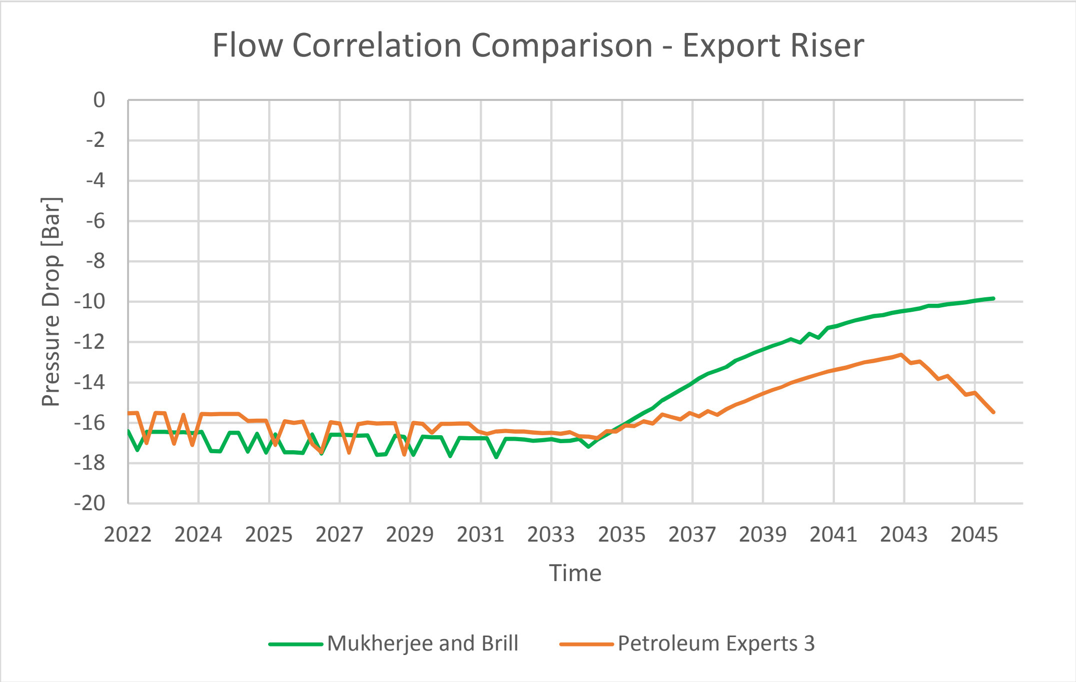


Figure 7.2: Flow correlation pressure drop comparison - Export riser - Topside Case 2B.

As the pressure loss calculations for the riser will impact the prediction results for the production lifecycle, an additional verification model was established in the process simulation software Aspen HYSYS. The Petroleum Experts 3 and the Murkhjee and Brill flow correlations models studied in GAP are not available in HYSYS, meaning a different pipe correlation had to be used. A study performed by the technology company Aspentech, which is the producer of the process simulation software, compared multiphase flow prediction results from their software with experimental data obtained from The Tulsa University Fluid Flow Project. For pipes with vertical geometry, the results show that the model developed by Aziz and Govier (1972) gives the most accurate results together with the Tulsa Unified Model (Aspentech, n.d.). When running a comparison between one of the time-steps from the GAP prediction and the Aspen HYSYS model using the Tulsa Unified Model, the results show the best alignment with the Petroleum Experts 3 flow correlation. Based on the information obtained from the literature and the comparison results with GAP, the Petroleum Experts 3 flow correlation was selected for the vertical pressure drop predications. Table 7.1 shows the flowrate with associated pressure drops for the time-step from the GAP prediction that was used for the comparison with HYSYS. The deviation in the pressure drops predicted by HYSIS from the GAP model predications are shown in brackets. The HYSYS model is illustrated in Figure 7.3.

Table 7.1: GAP prediction time-step 01.09.2032 - Topside Case 2B - (HYSYS deviation shown in brackets).

Flowrate [MMSCFD]	Pressure Drop Import Riser [Bar]	Pressure Drop Export Riser [Bar]
600.5	25.1 (8.2%)	- 16.4 (-3,8%)

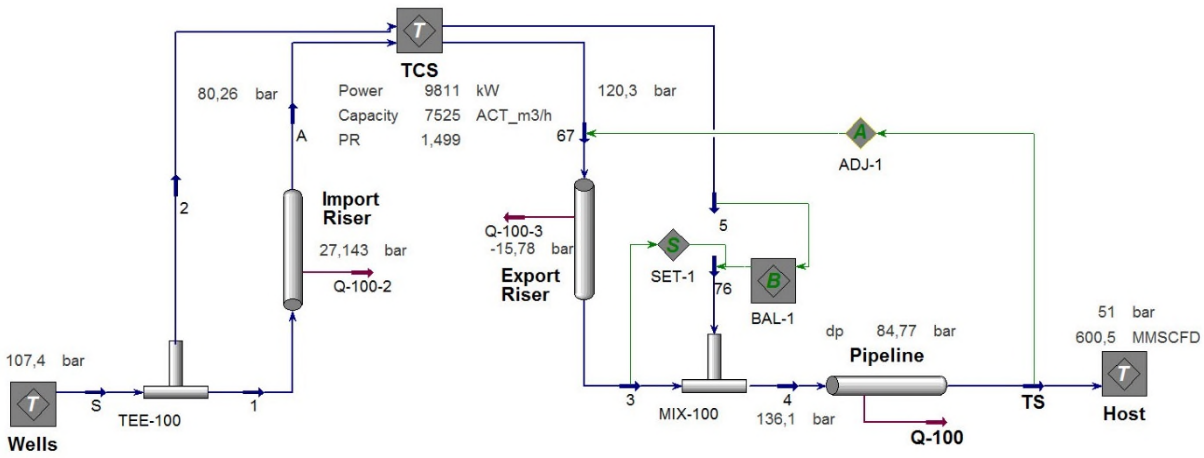


Figure 7.3: HYSYS reference case - GAP prediction time-step 01.09.2032 - Topside Case 2B.

Taking all the considerations regarding the flow correlations and the associated uncertainty into account, it is evident that the selection of correlation will impact the prediction results to some extent. Through the described verification process of the selected flow correlation, there is however no indication that the trends that are observed in the results of the comparison between a topside and subsea system will change as long as a reasonable flow correlation is applied.

7.1.2. Production system design parameters

A number of production system design parameters have the ability to impact the GAP simulation results. Such design parameters include water depth, number of import and export risers, pipeline sizes, fluid composition, reservoir characteristics and host facility minimum arrival pressure and production rate. In the creation of the analysis cases a lot of these design parameters were varied to study how they would impact the overall results. The general observation was quite naturally that it all comes down to how changing the parameters affected the overall system pressure drop. All cases gave the same trends when running predictions, although with some differences in overall results. As an example, a lower host facility arrival pressure led to higher flowing velocities in the import risers, increasing the frictional gradient contribution to the total pressure drop in the riser. This could however be offset by modifications to the import riser dimensions or by increasing the number of risers. Adding another riser will have cost impact however, and depending on water depth and many other variables it could easily start to impact the overall topside design in a way that is not desirable at some point, such that it becomes a limitation.

7.1.3. CO_2 emission calculations

In calculation of the CO_2 emissions it is assumed the power is generated from offshore gas turbines for the topside cases and that power is supplied from shore through umbilicals for the subsea cases. As shown in Table 5.12, the average emission factor for power generation onshore is lower than the one for power generation from gas turbines. This works in favor of the subsea solution when performing the comparison of CO_2 emissions, but the accumulated energy consumption shows that a subsea solution will be more effective and have less emissions also if the same emission factor would be assumed. Depending on field location and nearby infrastructure, a plausible scenario could be that power for the subsea cases is supplied from gas turbines on an offshore facility or from an onshore power plant running gas turbines. Alternatively, the power supply could come from shore also for a topside system, which would reduce emissions by approximately 25% if the emission factor for shore power for the average world energy mix is assumed.

As described in section 5.3, an assumption was made when creating the analysis cases that the one-time energy consuming activities, e.g. the manufacturing work required to build the systems, would have little impact on the overall emissions and that it would therefore be omitted in the analysis. The emissions related to production of materials were included as an example on how these type of emissions impact the totality, and it can be observed in the results in Table 6.6 and Table 6.8 that the impact is very limited for both the topside and the subsea system. This confirms that the contribution from one-time activities are likely to be dwarfed when comparing with the continuous energy consumption of the compressors, and that the overall result trends are not likely to be impacted by these activities. When performing a lifecycle assessment of overall emissions from the gas industry, IEA also excluded factors like manufacturing from their analysis as it was thought to have limited impact (International Energy Agency, 2018).

When looking at the contributions from the support systems of the topside facility these have a significant impact on the overall emissions also when a simplified topside facility is selected as is the case in this analysis. For larger and more complex topside facilities, even more power would be required to supply the topside support systems. In the plan for development and operation (PDO) that was submitted from Equinor for the Åsgard Subsea Compression Project, they described that a compression platform was calculated to have a power demand of 41 MW, while a subsea compression system would only need 25 MW (Statoil, 2011). The results show that having a large and complex topside requiring a lot of utility power will have substantial impact on overall emissions in a lifecycle perspective.

7.2. Comparing results

The results from the complete lifecycle evaluation shows a significant difference in energy consumption and CO_2 emissions for the topside and subsea system, both related to the compression work and to the support systems on the topside facility. The subsea compression system requires less power. This aligns with the statements from both Time and Torpe (2016) and Lima et al. (2011), who suggest that a subsea compression system is more energy efficient because of a reduced pressure drop in the pipelines. The consistently lower pressure drop for the subsea solution will also allow a higher flowrate for a longer period, meaning the production can be accelerated in line with statements from (Vinterstø et al., 2016). The results further show that the reservoir pressure is lower at the abandon date for the subsea system in both cases. A lower reservoir pressure directly translates to increased recovery, as it means more fluids have been extracted from the reservoir. The observation that subsea gas compression results in increased recovery agrees with one of the main advantages described by Lima et al. (2011) in their paper *"Subsea Compression: A Game Changer"*.

When looking at the emissions from both the topside and the subsea compression systems and comparing these with the global average of 18.1 kilos of CO_2 per BOE as reported by the IOGP member companies as described in section 1.5, it is easy to observe that gas production with compression in the defined cases for this thesis will contribute to lower average emissions. Also, when comparing with the average CO_2 intensity of 10 kilos per BOE that Equinor reports for their upstream production, the emission intensities of the analyzed cases would be attractive to lower average emissions further. The lower emissions from the compression systems is not explained by the system solution itself, but rather that the CO_2 intensity of gas production appear to be up to 4-5 times lower than emissions related to oil production (Fæhn et al., 2013).

The results further indicate that the CO_2 emissions per BOE produced will increase with time. This is consistent with the observations of Gavenas and Rosendahl (2015) who investigated CO_2-emission intensities of Norwegian oil and gas extraction using field specific data. In the study they observed that as a field's hydrocarbon production volumes start to decline, the emission intensity per produced volume will increase. They point out that the fields energy consumption is likely to be at the same level, even with reducing production volumes. This is easily relatable to the assumption made in this analysis that the power demand of the support systems for the topside facility will be constant. In addition, there will be increased energy consumption by the compression systems. To illustrate how installation of a compression system can affect a field's CO_2 emissions, an analysis was performed for Equinor's Kvitebjørn field. The analysis can be found in Appendix B. A compressor package was installed at Kvitebjørn in 2014, after the field had already been in production for several years. As the results in Appendix B show, the emissions per BOE produced increased significantly after the compressor package was installed.

7.3. Larger setting

Regardless of how installing a compressor package to increase recovery is likely to impact a field's CO_2 emissions, most operators have an established goal to increase recovery of their reservoirs. This goal seems to coincide with the interest of policy makers. As an example, the largest political party in the Norwegian government, Høyre, state on their website that they want to contribute to an increased recovery rate on the Norwegian continental shelf by including a demand for an increased recovery plan when concessions are to be renewed (Høyre, n.d.). If the perspectives from the IEAs "World Energy Outlook 2018" report are included, where they in their New Policies Scenario describe that the world energy demand will grow with 26% between today and 2040, and that approximately 35% of the increase in this demand will be covered by gas, it can be established that gas is likely to play a key role in the energy mix for years to come (International Energy Agency, 2018). Following from the Pollution Control Act in Norway and the Industrial Emissions Directive 2010/75/EU in the EU, operators are further responsible to perform best available technique assessments when planning new field developments. A subsea compression system is likely to represent BAT in many of the considerations that make out a BAT assessment. Utilizing subsea compression to increase recovery, while still being able to deliver gas at attractive emission levels is therefore a good way to secure the gas that is required to meet future demand.

When looking at the average emissions per BOE collected from the IOGP member companies, 68% of the emissions come from energy usage and 25% comes from flaring (International Association of Oil & Gas Producers, 2018). Flaring is excluded from this analysis, and close to all emissions are caused by the continuous energy consuming activities over the system lifecycles. If the emissions from the energy supply could be reduced, the total emissions from the upstream production would automatically be reduced as a result. Electrification is the main focus area in trying to obtain cleaner power supply and can be done by supplying power from the onshore grid. Alternative solutions like generating power from wind-mills installed close to the offshore installations are also considered. The IEA estimate that electricity supplied from an onshore power grid would need to have emission intensity of less than 0.5 tonne of CO_2 per megawatt-hour to have a real effect on overall emissions from the upstream production when replacing local electricity production from gas turbines (International Energy Agency, 2018). In a study THEMA Consulting Group performed for Equinor, they looked at electrification of the Snorre Expansion Project on the Norwegian continental shelf. The main target of the study was not only to consider CO_2 emissions, but to evaluate the efficiency of electrification as a climate measure in a socio-economic perspective. They concluded that electrification would reduce the CO_2 emissions, but that it was not beneficial in a socio-economic perspective as it would replace other cheaper climate measures in the market for emission allowances (THEMA Consulting Group, 2017). These types of considerations are however very complex and will vary with field specific data as distance from shore. Other variables as price of power from the onshore grid and if looking within the EU, how CO_2 emission prices will develop, also adds uncertainty to predictions as many projects have long lifecycles. This illustrates how complex evaluations of emission reducing measures can be, and why reducing the actual energy consumption in upstream production is an important factor in reducing overall emissions.

8. Conclusion

8.1. Main findings

- The average emissions of CO_2 per BOE produced is approximately 53% lower from the subsea system in both the cases evaluated. This is because of a lower system pressure drop and accelerated production, causing the total energy consumption of the subsea system to be approximately 37% and 38% lower over the lifecycle for Case 1 and Case 2 respectively.
- The emissions from the topside support systems are a significant contribution to the overall emissions over the lifecycle. These make up approximately 23% of the total topside emissions in Case 1 and Case 2. This constitutes approximately 44% and 46% of the difference in total emissions between the two systems in Case 1 and Case 2 respectively.
- The energy consumption of the topside support systems is dominant in the difference in total energy consumption of the two systems in both Case 1 and Case 2, making up 61% and 62% of the difference for the two cases respectively.
- Including the one-time emissions from production of the construction materials that go into building the systems has a negligible effect on the lifecycle emissions and on the comparison between the two systems.
- The accumulated production volume is higher for the subsea system in both cases, representing significant additional revenue. This is a result of a lower system pressure drop for the subsea system, allowing a further drawdown of the reservoir pressure when compared with the topside system.
- Utilizing gas compression to increase recovery is a good way to secure the gas that is required to meet the future energy demand at attractive emission levels compared with average emissions in upstream oil and gas production.

8.2. Further work

A number of production system design parameters have the ability to impact the GAP simulation results. Such design parameters include water depth, number of import and export risers, pipeline sizes, fluid composition, reservoir characteristics and host facility minimum arrival pressure and production rate. In creation of the analysis cases a lot of these design parameters were varied to study how this would impact the overall results. The fact that the solver iterations in GAP requires a lot of computational power and can take several hours of calculation time to solve quickly limited the ability to test how different input changes affected the overall results. A further sensitivity analysis to determine how these different variables impact the overall results could be done, with a target to identify the variables affecting the overall results the most.

As this analysis only considered a dry gas compression system, it could also be interesting to perform a similar study for a wet gas compression system to see if that provides similar results.

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10. Appendices

Appendix A – Integrated production modeling results – Case 2

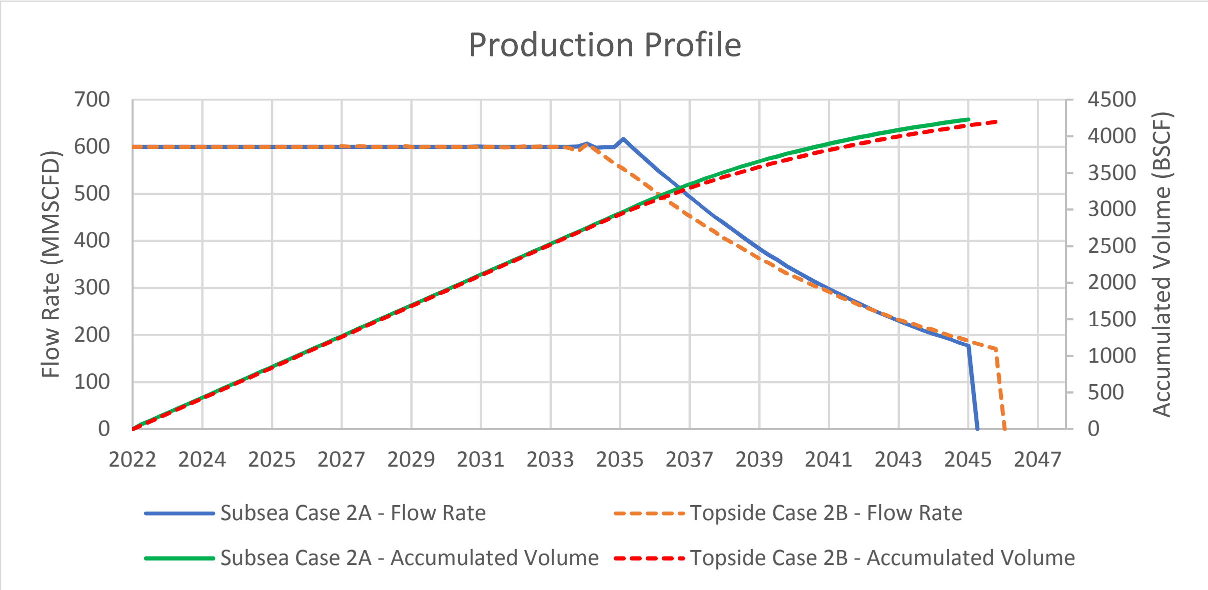

Figure A.1: Production profile - Case 2A vs Case 2B.

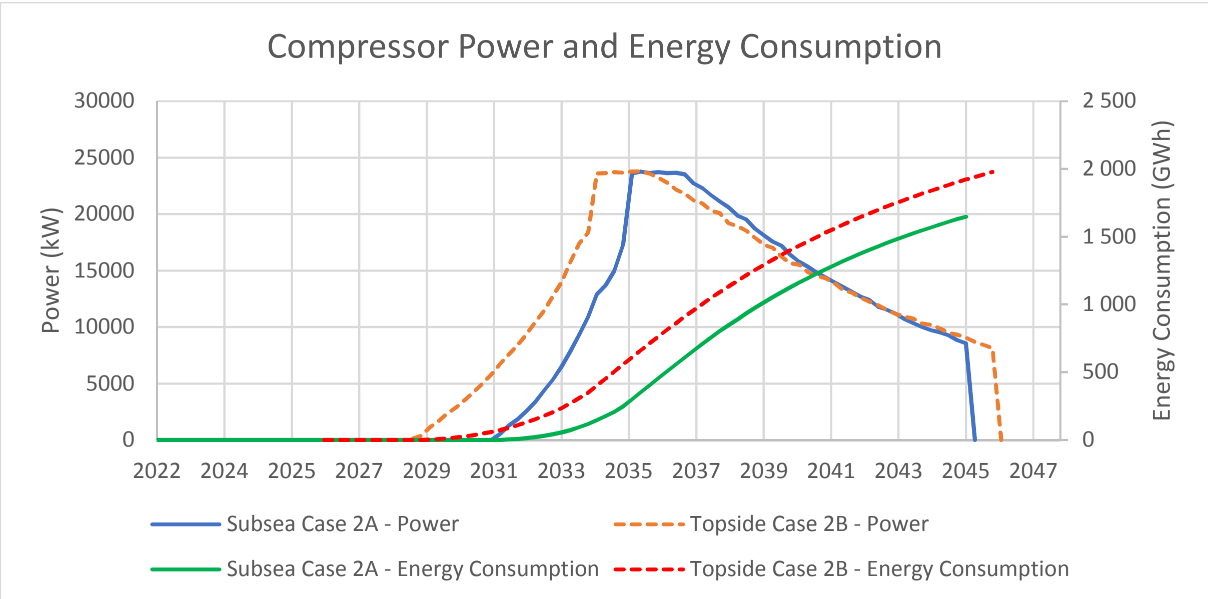

Figure A.2: Compressor power and energy consumption - Case 2A vs Case 2B.

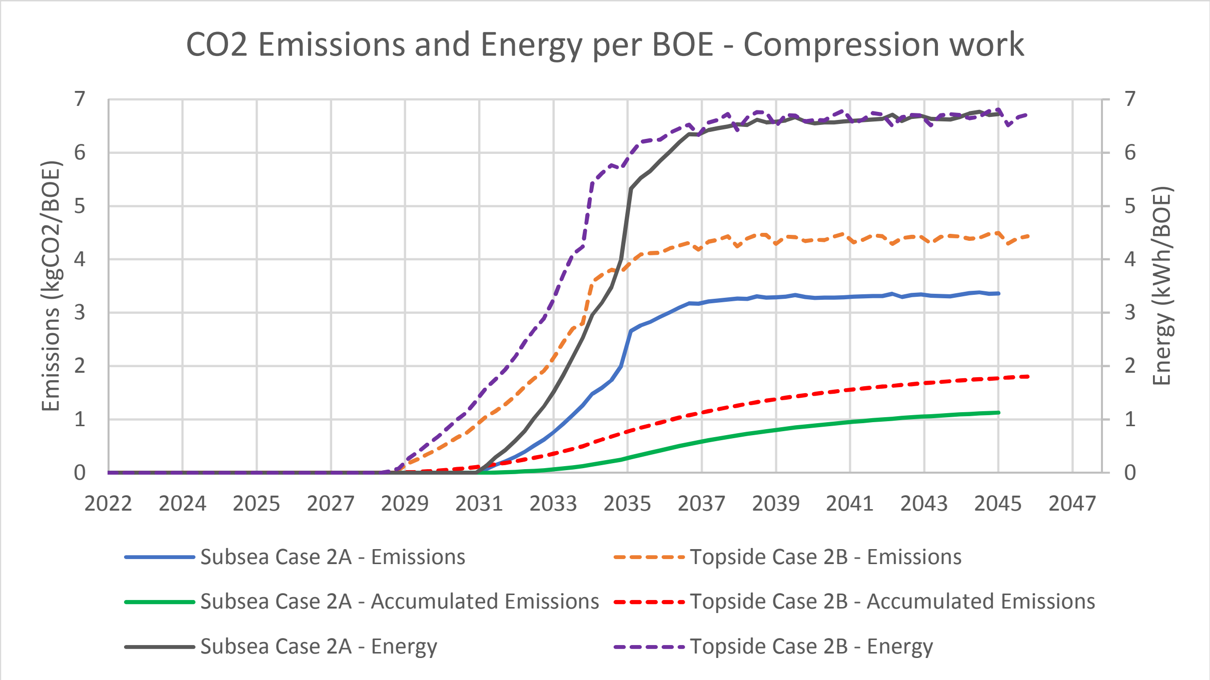

Figure A.3: CO_2 Emissions & energy per BOE – Case 2A vs Case 2B.

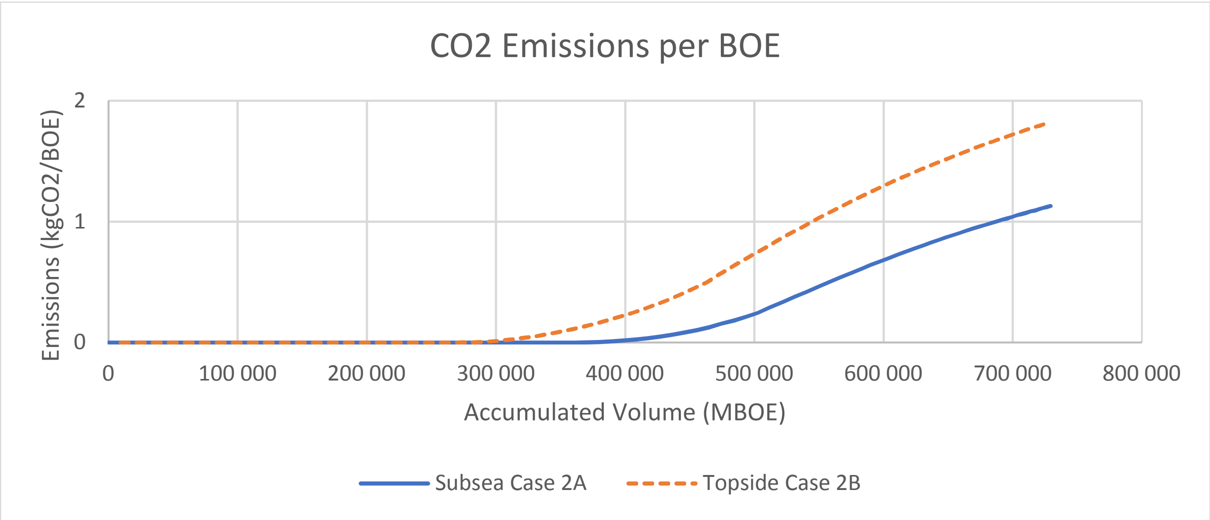

Figure A.4: CO_2 Emissions as a function of accumulated volume – Case 2A vs Case 2B.

Appendix B – Emissions on Kvitebjørn

A simple CO_2 emission analysis was performed for the Kvitebjørn gas field operated by Equinor. The Kvitebjørn field is a gas and condensate field where production started in 2004. In 2010 Equinor announced that they would be installing a new module on the platform containing a gas-turbine driven compressor package to increase recovery, as the field would not be able to maintain the same production level beyond 2013 without pressure support. The compressor package was installed in 2014 and is expected to increase the recoverable volumes by approximately 35 million standard cubic metres of oil equivalents (Equinor, n.d.-b). By looking at the numbers Equinor reported to the Norwegian Environment Agency for production volumes and CO_2 emissions in the period from 2009-2017, a clear shift can be observed in the CO_2 emissions after the compressor package was installed in 2014 as illustrated in Figure B.1 (Norwegian Environment Agency, n.d.).

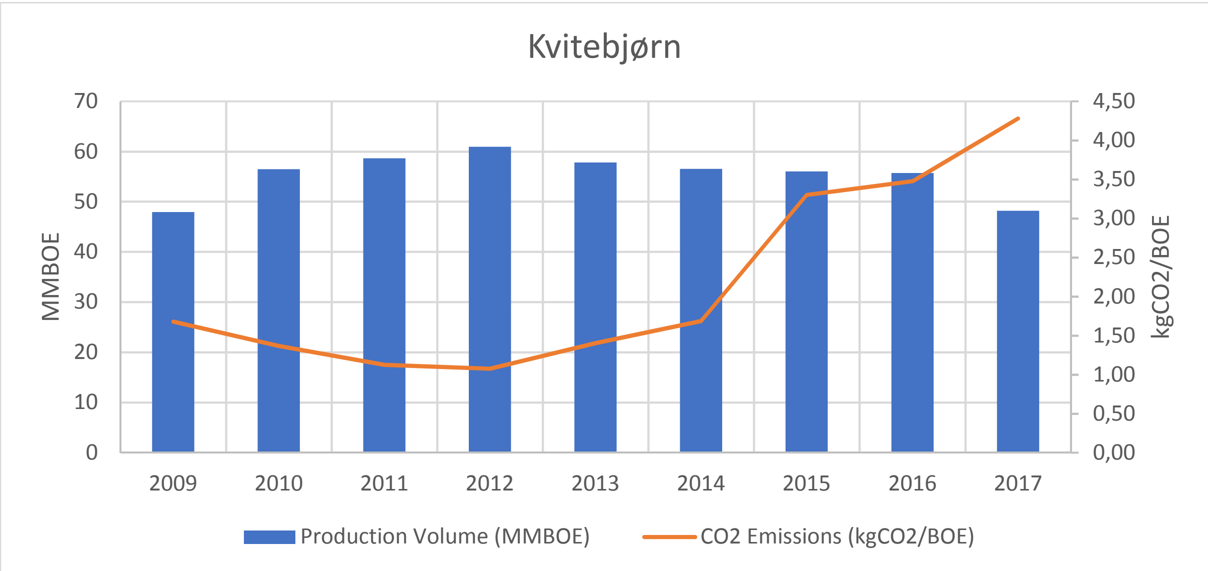

Figure B.1: CO_2 emissions per production volumes at Kvitebjørn from 2009-2017.

Norges miljø- og biovitenskapelige universitet
Noregs miljø- og biovitskapelege universitet
Norwegian University of Life Sciences

Postboks 5003
NO-1432 Ås
Norway