Impact of geological uncertainty on project valuations for offshore CO_2-enhanced oil recovery

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Summary

Carbon capture and storage (CCS) can contribute substantially to the decarbonization of the energy system. However, the public resistance against onshore CO_2 storage and the lack of a viable business case for CCS cause delay in private investments. CO_2-enhanced oil recovery (CO_2-EOR) is often proposed as a promising business case for CCS, because the revenues from incremental oil recovery can offset the costs for CCS. Offshore CO_2-EOR is of particular interest because it is not hindered the public resistance as is the case with onshore storage of CO_2. Traditional net present value based calculations in general indicate positive project economics but wide-scale deployment is hampered because there is no commercial application.

These traditional investment decisions neglect the geological uncertainties of the reservoirs for offshore CO_2-EOR. This thesis proposes an improved valuation method for projects by using a real option decision scheme for offshore CO_2-EOR that includes uncertainties for multiple fields. Real options offers flexibility and the ability to respond to the performance of the projects. A techno-economic simulator is developed, starting from an existing simulator that is designed for carbon capture and storage. The new simulator is used to valuate seven generic CO_2-EOR projects clustered in the North Sea where the investment decisions were simulated.

The alpha version of the techno-economic simulator PSS IV provides a good starting point for realistic assessment of potential CO_2-EOR projects in the North Sea. Well-founded investment decisions were made based on the real option values of the alternatives to either stop primary production or activate CO_2-EOR. Realistic forecasts were made for potential CO_2-EOR projects in which geological uncertainty of CO_2-EOR field performance is taken into account. All simulated primary oil production projects were retrofitted to CO_2-EOR, but when and where EOR is activated is strongly influenced by the stochastic oil market price, as well as the CO_2-EOR field performance.

The main benefits of the real option approach in comparison with traditional investment decisions is that it is possible to make realistic assessments of offshore CO_2-EOR projects including the complete uncertainty range of the geological, techno-economic and scenario parameters.

These new simulations will for the first time provide near-realistic insights into the cost-benefit balance of EOR projects in an offshore European context. This may help to provide realistic outlooks for EOR, as well as stimulate demonstration and full-scale projects.

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The research is framed in the PhD research of Kris Welkenhuysen about the integration of geoscientific data and uncertainties in techno-economic forecasting on carbon capture and storage.

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Master program Energy Science

This thesis is part of the research master Energy Science. The master program (120 EC) provides a deep understanding on how energy systems work, and how they can be analyzed and modeled. Moreover, the program gives a detailed insight in energy technologies. The program is part of the Graduate School of Geosciences and is organized by the Department of Innovation, Environmental and Energy Sciences, Copernicus Institute of Sustainable Development, Utrecht University.

I have successfully completed all mandatory courses for Energy Science including the System Analysis track and three elective courses: Fossil Resources, Technology Related Venturing, and Sustainable Entrepreneurship.

Master thesis

The proposal for this study is written in February 2014. The starting date for the study was March 3rd, 2014. The study was supervised by dr. ir. Andrea Ramírez, associate professor at the Copernicus Institute of Sustainable Development at Utrecht University. The external supervisors were dr. Kris Piessens and Kris Welkenhuysen MSc from the Geological Survey of Belgium of the Royal Belgian Institute of Natural Sciences (RBINS).
I was a research intern at the Royal Belgian Institute of Natural Sciences from March to June 2014.

Annotation Sustainable Entrepreneurship & Innovation

The annotation Sustainable Entrepreneurship & Innovation is a university wide master track that is complementary to the master program Energy Science. This master thesis qualifies for the annotation because 1) offshore CO_2-EOR is addressing a new combination of processes, 2) at this moment it is not yet commercially applied, 3) data is collected about these new business activities in which a realistic case is used and 4) the research component is larger than 15 ECTS.

Climate-KIC master label

Climate-KIC is a knowledge and innovation community (KIC) founded by the European Institute of Innovation and Technology (EIT) that focuses on climate entrepreneurship. This research qualifies for the master label because it fits in the Climate-KIC targets of *making transitions happen* (developing a business case for carbon capture and storage), *industrial symbiosis (*CO_2 is used as a feedstock for EOR), and *greenhouse gas monitoring* (impact assessment of CO_2-EOR).

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Abbreviations

bbl	barrel of crude oil (42 US gallon, approximately 159 liter)
CAPEX	Capital expenditure
CO_2	Carbon dioxide (a greenhouse gas and also used for enhanced oil recovery)
CO_2-EOR	Enhanced oil recovery by injecting CO_2
CCS	Carbon capture and storage
CGS	CO_2 geological storage
CCUS	Carbon capture and underground storage
ECTS	European Credit Transfer System, 1 EC is the equivalent of 28 hours of study
ETS	Emission trading scheme, i.e. pricing CO_2 emissions
GHG	Greenhouse gases (e.g. CO_2)
GSB	Geological Survey of Belgium
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
M bbl	Million barrels of oil (approximately 1,590,000 m^3 oil)
Monte Carlo	Method for repeated random sampling to obtain numerical results
OOIP	Original oil in place
OPEX	Operational expenditure
PSS	Policy Support System, techno-economic simulator developed by RBINS
RBINS	Royal Belgian Institute of Natural Sciences
t	tonnes (1,000 kilogram)
VBA	Visual Basic for Applications
WAG	Water-alternating-gas injection schemes

PART A: RESEARCH CONTEXT

1 Introduction

There is broad consensus in the scientific realm on the anthropogenic cause of global climate change, i.e. the emission of greenhouse gases (GHGs) (e.g. IPCC, 2013). Out of all anthropogenic GHG emissions, CO_2 is the major driver of increased radiative forcing resulting in warming of the earth's surface (IPCC, 2013). Due to human activity, the CO_2 concentration currently exceeds pre-industrial levels by approximately 40% (IPCC, 2013). The average atmospheric concentration of CO_2 is 401.6 parts per million as of May 2014 (Scripps, 2014). To stabilize the CO_2 concentration in the atmosphere within acceptable levels, the production can be reduced, or the released CO_2 can be used or stored.

1.1 Carbon capture and storage

Carbon capture and storage (CCS) encompasses the separation of CO_2 from industrial or energy-related sources and transportation the captured CO_2 to a (underground) storage location, for long-term isolation of CO_2 from the atmosphere (IPCC, 2005). CCS could play an important role in CO_2 mitigation strategies to achieve the reduction goals. The International Energy Agency has calculated a techno-economic optimum to reach the 2° C target[4] in which CCS has a 14% share in annual GHG emission reductions in 2050, or a cumulative 17% until 2050 (IEA, 2013), as shown in Figure 1-1. Mitigation strategies without CCS are possible, but will lead to a 40% increase of investments for electricity generation alone, totaling $2,000 billion over 40 years (IEA, 2012a).

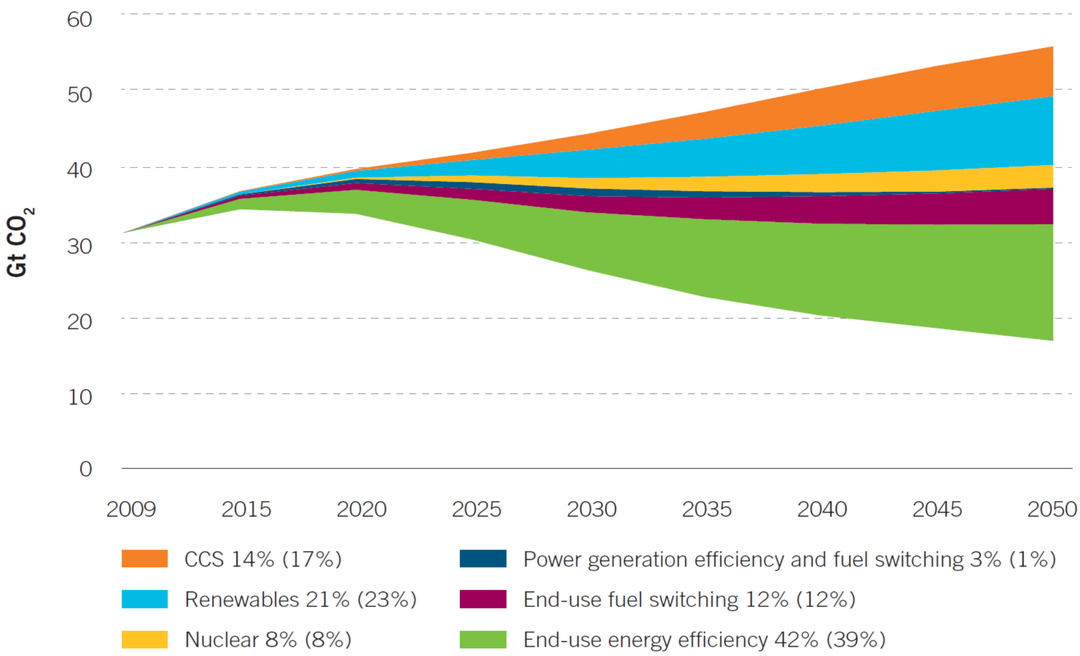

Figure 1-1: Energy-related CO2 emissions reductions by technology. Percentages represent the share of cumulative emission reductions to 2050. Percentages in brackets represent the share of emissions reductions in the year 2050. In Global CCS Institute (2013) from IEA (2012a).

[4] The 2° C target describes how technologies across all energy intensive sectors may be transformed by 2050 for an 80% chance of limiting average global temperature increase to 2 °C (IEA, 2013b)

Without adequate policy intervention, CO_2 emissions will continue to rise, because fossil fuels are expected to dominate the total primary energy supply until 2050 (IEA, 2013b). The costs of polluting can be internalized by introducing CO_2 emission trading schemes (Ellerman, Convery, & Perthuis, 2010). For CCS technology to become competitive with traditional coal-fired power plants, a CO_2 market price of higher than €37 per tonne is needed for coal-fired CCS power plants (ZEP, 2011a). However, the EU ETS (European Union Emission Trading Scheme) CO_2 market price per tonne fluctuated between €3 and €8 in the period January 2012 – January 2014 (ThomsonReuters, 2014). Therefore, the current price levels of the EU ETS are insufficient for the uptake of CCS.

1.2 CO_2-enhanced oil recovery

Although CO_2 is regarded as a pollutant in most situations, CO_2 can also be turned into use. CO_2 can be used for enhanced oil recovery (EOR), other oil and gas operations (e.g. fracking wells), the food and drink industry (e.g. beverage carbonation, coffee decaffeination, wine making, food processing) and horticulture (Global CCS Institute, 2011). Globally, the CO_2 use is approximately 80 Mt/y (million tonnes per year)[5] and is dominated by the 50 Mt/y CO_2 demand for EOR in the United States (Global CCS Institute, 2011).

EOR is a generic term for various techniques to increase the yield of oil fields. The injection of CO_2 into oil fields that are approaching the end of their economically productive life is called CO_2-enhanced oil recovery (CO_2-EOR). The CO_2 is transported from a source to the injection well. Nearby, at the production well, oil is produced and accompanied by part of the injected CO_2. The produced CO_2 is separated and re-injected, thereby recycling the CO_2. Additionally, the CO_2 can potentially be stored into the geological reservoir. Oil reservoirs are appropriate storage sites for CO_2 because they are known to contain hydrocarbons for millions of years (Gozalpour, Ren, & Tohidi, 2005). Figure 1-2 illustrates a simplified flowchart for oil and CO_2 in a CO_2-EOR project.

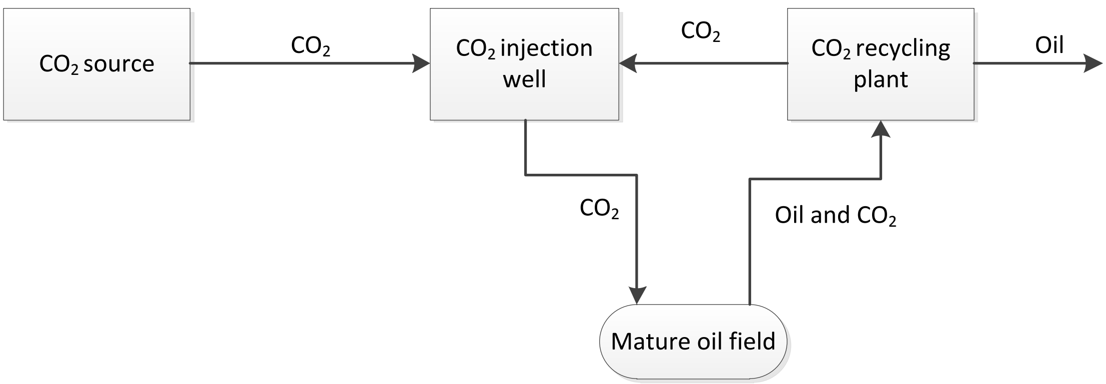

Figure 1-2: Simplified flowchart of oil and CO_2 in a CO_2-EOR project

CO_2-EOR has been used for over 40 years in oil fields in the United States. It was first applied in Scurry County, Texas in 1972 (US Department of Energy, 2014). Globally, there are more than 110 CO_2-EOR projects (Alvarado & Manrique, 2010). The majority of the CO_2-EOR projects are in North

[5] The large captive volumes of CO_2 (113 Mt/y) both generated and consumed in the industrial process of urea production are excluded from this number.

America (Koottungal, 2012). All these projects are onshore. Onshore CO_2-EOR is a proven technology, extensively covered by research (King, Gülen, Cohen, et al., 2013; Preston, Monea, Jazrawi, et al., 2005; Preston, Whittaker, Rostron, et al., 2009) and commercially applied (Whittaker, Rostron, Hawkes, et al., 2011). Less geological information is available offshore, because well density is lower (Gozalpour et al., 2005). Hence, the uncertainty of the geological characteristics increases. Combined with the inherently higher costs for offshore constructions and operations, the costs offshore are significantly higher. The majority of CO_2-EOR projects use CO_2 from natural sources (King et al., 2013; Muggeridge, Cockin, Webb, et al., 2014). However, some onshore CO_2-EOR projects (e.g. the IEA GHG Weyburn project) use pure industrial CO_2 sources, in which geological storage of CO_2 is also demonstrated (Alvarado & Manrique, 2010; Kovscek & Cakici, 2005; Preston et al., 2005, 2009).

1.3 Research aim

CCS can contribute substantially to the decarbonization of the energy system (IEA, 2013b). However, the public resistance against onshore CO_2 storage (Sanders, Fuss, & Engelen, 2013) and the lack of a viable business case for CCS cause delay in private investments (Mendelevitch, 2014). CO_2-EOR is often proposed as a promising candidate business case for CCS, because the revenues from incremental oil recovery can offset the costs for CCS (e.g. Middleton, Bielicki, Keating, & Pawar, 2011). As an enabling technology for offshore storage of CO_2, EOR is of particular interest because it is less hindered by public resistance to onshore storage of CO_2. Traditional net present value based calculations in general indicate positive project economics (e.g. Kemp & Sola Kasim, 2012) but commercial application fails to appear (US Department of Energy, 2014). Delays in investments hamper the wide-scale deployment of CCS.

The aim of this thesis is to improve the valuation method for projects by proposing a real option decision scheme for offshore CO_2-EOR that includes uncertainties for multiple fields. Geological uncertainties are included, such as oil production curves, CO_2 injection rates and the ratio of incremental oil production over the amount of injected CO_2. Additionally, scenario parameters such as oil market prices and CO_2 market prices are also included. Real options analysis offers flexibility and the ability to respond to the geological reality. A techno-economic simulator is used to valuate multiple CO_2-EOR projects in a cluster and simulate the investment decisions.

1.4 Research questions

In accordance with the research aim, the main research question is:

What is the impact of including uncertainties and flexibility on the value of offshore CO_2-enhanced oil recovery projects compared to traditional investment decisions?

Two sets of additional research questions are formulated to (1) design the methodology for the simulator and (2) interpret and analyze the results from the simulations.

(1) Research questions underpinning the development of the *Policy Support System* for ad-hoc CO_2-EOR simulation:

- What are the relevant techno-economic parameters for offshore CO_2-EOR projects and how can they be quantified?
- How can the dynamics of primary oil production and enhanced oil recovery be modeled using the existing techno-economic simulator *Policy Support System*?
- What are the differences in costs and routing optimization for ship and pipeline transport of CO_2?

(2) Research questions for interpreting and analyzing the simulation results

- What is the impact of the CO_2 market price, oil market price and geological uncertainty on the project economics of offshore CO_2-EOR?
- To what extent is the timing of retrofitting to CO_2-EOR from primary oil production influenced by geological and economic uncertainty?
- What is the cost and revenue structure of the offshore CO_2-EOR projects?

1.5 Relevance

CO_2-EOR is particularly interesting in the North Sea region because of four reasons. First, a large capacity for offshore CO_2 storage in depleted oil and gas fields in the North Sea is expected[6]. Second, a large number of oil fields in the North Sea are suitable for EOR because they are in the mature phase. Therefore, infrastructure development can be vitalized (Klokk, Schreiner, Pagès-Bernaus, et al., 2010) and CO_2 injection can start simultaneously with other projects, which implies that the use of infrastructure can be optimized. Third, techno-economic potential studies have repeatedly confirmed positive economics for North Sea CO_2-EOR (Element Energy, 2012). Fourth, offshore storage of CO_2 is socially more accepted than onshore storage (Knoope, Guijt, Ramírez, et al., 2014).

Conventional oil resources are forecasted to experience a terminal decline in production; oil resources are being depleted (Sorrell, Speirs, Bentley, et al., 2010). Increasing efficiency of resource extraction – although controversial – can be regarded as a societal benefit because it is a form of cautious stewardship of limited resources. Figures of global capacity for CO_2 storage in depleted oil and gas fields are unreliable and have large deviations (Bachu, Bonijoly, Bradshaw, et al., 2007). By

[6] Estimations range from 870-1959 Mtonne (European Commission, 2005), 990 Mtonne (Scottish Centre for Carbon Storage, 2009), 1234 Mtonne (Mendelevitch, 2014), 4700 Mtonne (Godec, Kuuskraa, Van Leeuwen, et al., 2011)

analyzing the variability in reservoirs (i.e. geological uncertainty) and the operational flexibility (i.e. multiple locations at hand), this study contributes to the knowledge base of CO_2-EOR.

In addition, security of energy supply has emerged as an issue of great importance for Europe (Yergin, 2006) due to increased dependency upon energy imports, especially from the former Soviet Union, North Africa and Middle East (Hustad & Austell, 2004; Umbach, 2010). CO_2-EOR can moderate energy supply risks by sustaining oil production.

A second societal relevance is the progress of knowledge contributing to realizing CCS potential by advancing the assessment methodology of geological storage. Knowledge and experience of CO_2-EOR can spillover to several CCS related activities such as CO_2 capture, transportation, monitoring of CO_2, and legislation (IIASA, 2012). Hence, this study contributes to the broader theme of mitigating global climate change. Besides environmental motivations, commercial incentives play a role in the success of climate mitigation options. Sound business cases (i.e. CO_2-EOR) can provide a further step-up towards large-scale underground storage of CO_2.

1.6 Reading guide

This thesis is divided into four major parts. Part A includes an introduction (this chapter), background on CO_2-EOR (chapter 2) and literature review about CCS and CO_2-EOR infrastructure modeling (chapter 3). Part B deals with the methodologies by explaining the techno-economic simulator PSS (chapter 4) and the methodological framework (chapter 5). Part C deals with the inputs that are used in this study for CO_2 sources (chapter 6), transport by ship and pipeline (chapter 7), primary and enhanced oil recovery (chapter 8) and scenario parameters (chapter 9). Part D deals with the results and analysis (10), discussion (chapter 11) and conclusion (chapter 12).

2 CO_2-enhanced oil recovery

This chapter provides a basic understanding of CO_2-EOR. First, a technical description of CO_2 is given and the sources of CO_2 are addressed. Later, the basic mechanisms of transport of CO_2 by pipeline and ships are explained. Then, the dynamics of primary as well as enhanced oil recovery are addressed.

2.1 Technical description of CO_2

CO_2 is an odorless, colorless and non-flammable gas at normal pressure and temperature. The critical point (at 7.38 MPa and 31.1 °C) is a distinct feature (NIST, 2011). When the critical point is reached, the CO_2 becomes supercritical. In the supercritical state, the substance has the viscosity of a gas but the density of the liquid state. These characteristics are favorable for transportation. Moreover, supercritical CO_2 has excellent solvent properties (DNV, 2008) which proves to be effective for extracting hydrocarbons that would otherwise be trapped in a reservoir (Sharman, Aps, & Denmark, 2003). Supercritical and liquid CO_2 are both considered being in the dense phase (Knoope et al., 2014). Figure 2-1 shows the phase diagram with the different physical states, induced by changes in temperature and pressure.

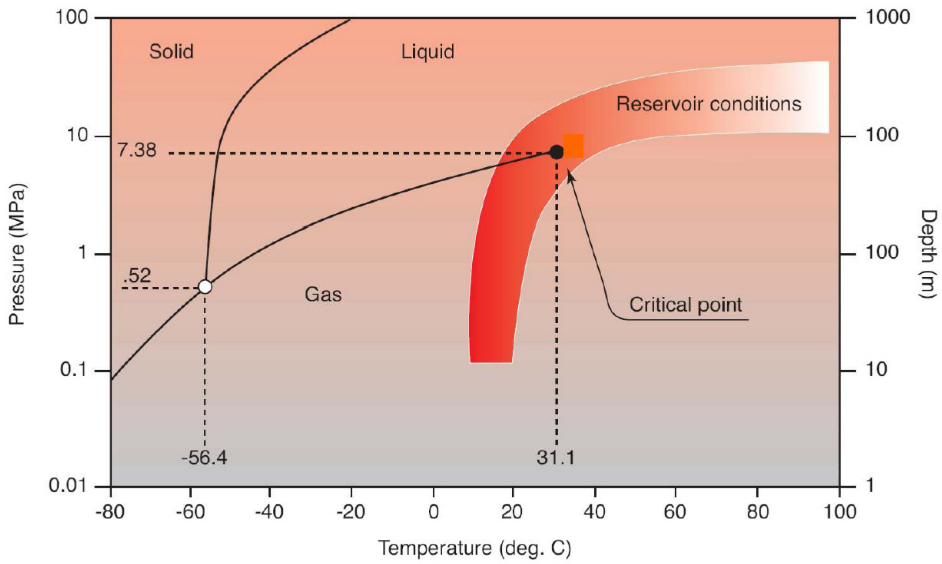

Figure 2-1: Pressure and temperature conditions of pure CO_2. Reservoir conditions are also indicated (by depth). CO_2 that has a temperature or pressure above the critical point (7.38 MPa and 31.1 °C) is in the supercritical phase. From Meer (2005) in NOGEPA (2008).

2.2 CO_2 sources

Large stationary point sources of CO_2 are favorable for CCS (IIASA, 2012). The first step in the CCS chain – and also the largest in terms of costs – is to capture the CO_2 (IPCC, 2005). Capturing CO_2 can be done by concentration, recovery or using a high purity CO_2 stream. The capture technology options include pre-combustion, post-combustion and oxyfuel combustion (IPCC, 2005).

For instance, during power generation, CO_2 is produced when burning fossil resources. The flue gasses are normally emitted into the atmosphere. However, the CO_2 can be captured from the flue gasses. The composition of the CO_2 stream depends on the source type, the capture technology and the fuel use. Impurities can have a great impact on the transport requirements such as the design of the pipeline. When CO_2 has a large content of water, the mixture becomes highly corrosive and weakens the pipeline integrity. The CO_2 has to meet the minimum miscibility pressure (MMP), i.e. the CO_2 and the oil need to be miscible in order to produce the incremental oil. The MMP is met when the crude oil has an API[7] value higher than 24° (density < 910 kg/m^3) and when the pressure is higher than the MMP (Ramirez, Brouwer, & Van den Broek, 2011). Minimizing contaminants and consequently the risk for pipeline or ship damage is important, although too stringent purity requirements have impact on the capture costs and technology options (Ramirez et al., 2011). Different requirements for CO_2 purity can be found in literature for the purpose of CCS, but less information is available for CO_2-EOR. Table 2-1 shows the CO_2 requirements for CO_2-EOR.

Table 2-1: CO_2 requirements for EOR. Adapted from Mohitpour, Jenkins, & Nahas (2008)

Components	Content	Reason for concern
CO_2	≥ 95%	MMP[8]
Nitrogen	≤ 4%	MMP
Hydrocarbon	≤ 5%	MMP
Water	≤ 480 mg/m^3	Corrosion of pipeline
Oxygen	≤ 10 ppm	Corrosion of pipeline
H_2S	≤ 10-200 ppm	Safety
Glycol	≤ 0.04 ml/m^3	Operations
Temperature	≤ 65 °C	Pipeline material (incl. coating)

This thesis assumes a near pure CO_2 stream (95-100% purity) that is in accordance with the MMP requirements and other issues such as corrosion and safety.

2.3 Pipeline transport

This section gives a description of the current state of pipeline infrastructure, the specifics of CO_2 transport by pipeline and the cost factors for CO_2 pipelines. The parameters that are used in this thesis are discussed in chapter 0.

2.3.1 Current status of pipeline infrastructure

Pipeline technology is a reliable and mature technology that is useful for transporting large quantities of e.g. oil, natural gas, condensate, CO_2 and water (Guijt, 2004). The safety risks are known and can be minimized by risk abatement technologies and safety measures (Damen, Faaij, & Turkenburg, 2006). Worldwide, there are large pipeline networks. To illustrate this, the total pipeline length for transport of natural gas in the US is more than 490,000 km (EIA, 2008). Currently, there are 6,300 kilometers of CO_2 pipeline transport (Global CCS Institute, 2013). The majority (80%) of the existing infrastructure is used to transport CO_2 within the Permian Basin of West Texas for CO_2-EOR (Dooley, Dahowski, & Davidson, 2009). CCS and industrial use of CO_2 also requires large-scale pipeline infrastructure (IEA GHG, 2013). Offshore pipelines are used since the 1947, when a pipeline was laid in the Gulf of Mexico, 17 km from the shore at a depth of 6 meters (Palmer & King, 2008).

[7] API is a measure how the density of a petroleum liquid compares to water
[8] Minimum miscibility pressure

Nowadays, pipelines have been laid at depths of more than 2,200 m (IPCC, 2005), while the maximum depth of the North Sea is only 700 m.

2.3.2 CO_2 transport by pipelines

CO_2 can be transported through pipelines as a liquid, gas, supercritical fluid or a mixture of liquid and gas. Gaseous CO_2 transport may only be cost effective for low mass flow rates and short distances, because of the low density (Knoope et al., 2014). A two-phase flow should be avoided because of multiple reasons. Cavitation can occur when local pressure falls sufficiently and vapor bubbles are formed that can erode the material. Vapor bubbles can also be formed due to boiling of the liquid, resulting in turbulence and cause damages to the pipeline (Ramirez et al., 2011). Moreover, a two-phase flow is difficult to handle by auxiliary equipment such as compressors and pumps (Knoope, Ramírez, & Faaij, 2013). Topographic variations and impurities could lead to a two-phase flow because of the induced pressure differences (IEA GHG, 2010; Vandeginste & Piessens, 2008). Therefore, the pressure should be higher than 7.38 MPa (Bahadori & Vuthaluru, 2010; Dongjie, Zhe, Jining, et al., 2012; McCoy, 2009; Piessens, Laenen, Nijs, et al., 2009; Vandeginste & Piessens, 2008). Liquid CO_2 transportation at a relatively low temperature could be favorable to reduce the pressure drop (Zhang, Wang, Massarotto, et al., 2006).

The main elements of a pipeline system are the pipeline itself, booster stations, metering stations, controls systems valves, and pipeline inspection gauges. Pure and dry CO_2 can be safely transported using carbon steel pipelines, because it causes no internal corrosion (European Commission, 2011). The higher pressure of the CO_2 requires thicker steel than natural gas transport. A doubling in pressure doubles the required thickness. Steel grades are classified by the composition and physical properties of the material. Steel with a higher yield strength has a higher steel grade and is more expensive per kilogram (Knoope et al., 2014). The costs per kilogram range from $€_{2010}$1170 for X42[9] to $€_{2010}$1790 for X120 (EU Standard S275Mb to S890QLc) (Knoope et al., 2014). Steel grades X60 are commonly used for onshore CO_2 transport (European Commission, 2011), while the stronger X80 is expected to dominate the market in the coming years (Knoope et al., 2014). Development of steel grades has less influence on the offshore pipeline material use. Although higher yield stress allows for less material use, the thickness of the steel for offshore pipelines should be at least 2.5% of the diameter (Knoope et al., 2014).

The outer walls of the pipelines must be coated to protect against corrosion. The coating is the primary barrier to corrosion of a pipeline (Palmer & King, 2008). Additionally, cathodic protection prevents corrosion at areas of damaged coating. Cathodic protection is an electrical way to increase the thermodynamic stability of the metal.

Booster stations (also referred to as pumping stations) can be used to counteract pressure losses along the pipeline. An economic trade-off is made between a higher inlet pressure, an increase in diameter and the placement of booster stations (Knoope et al., 2014). Placement of booster stations offshore is unfavorable because of the difficulties with offshore installation and maintenance and the need for an offshore platform with energy supply, which is very expensive (Knoope et al., 2014). Larger

[9] The X-number determines the yield strength in kilo-pounds per square inch

diameters are applied to reduce the pressure drop along the pipeline (Huang, Rezvani, McIlveen-Wright, et al., 2008).
Metering stations are used to measure and monitor the pipelines. The stations measure the flow of CO_2. Control systems are used to detect equipment malfunctioning or to adjust flow rates. Valves are used as gateways in the pipeline systems. They are used to control the flow of CO_2. Pipeline inspection gauges (pigs) are devices to inspect the pipeline. They are used to evaluate the interior, check for corrosion and defects. Pigging is crucial for maintaining pipeline integrity.

2.3.3 Cost components

Collecting several CO_2 sources into a single pipeline, i.e. a trunkline, is cheaper than transporting smaller amounts independently due to economies of scale (Ramirez et al., 2011). However, using high capacity trunklines requires large initial investment decisions (IPCC, 2005). The capital expenses are calculated based on material, labor, right of way (ROW)[10] and miscellaneous costs[11]. To illustrate the cost share of these cost segments, Figure 2-2 shows a typical cost structure of an offshore natural gas pipeline. The costs of natural gas pipelines show resemblance to CO_2 pipelines.

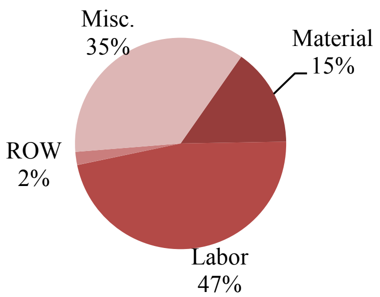

Figure 2-2: Division of labor, materials, right-of-way and miscellaneous cost for offshore natural gas pipelines (Grigoryev, 2006)

2.4 Ship transport

Ship and pipeline transport each have their financial and practical advantages and disadvantages. Ship transport is more energy intensive than using pipelines for transporting large volumes of CO_2 (Klokk et al., 2010). However, shipping can be favorable when transporting CO_2 over long distances, in smaller volumes, with shorter operational timeframes and an intermittent supply of CO_2 (CATO2, 2013b). The main differences in terms of economics between ship and pipeline transport are in the ratio of capital and operational expenses. Ship transport is usually less capital-intense compared to pipelines. Moreover, pipeline costs are nearly proportional to distance, while ship transport is marginally sensitive to this variable (CATO2, 2013b). This can be beneficial for smaller CO_2-EOR projects or when a non-continuous CO_2 source is used (CATO2, 2013b; ZEP, 2011a, 2011b).

Liquefaction and gas conditioning is one essential step for transporting CO_2 by ship. The investment costs for ship transport are determined by the costs for liquefaction, compression, intermediate

[10] ROW are the costs for the rights for a pipeline to cross a piece of land
[11] Miscellaneous costs include supervision, surveying, engineering, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads and regulatory filing fees (Piessens et al., 2009)

storage, and systems for ship loading and unloading. The operational expenses comprise labor costs, heavy fuel oil, energy costs, harbor fees and maintenance (CATO2, 2013b). CO_2 ship transport can benefit from the mature technology that is commercially used for transporting liquefied natural gas (LNG) and liquefied petroleum gas (LPG) (IPCC, 2005). CO_2 is transported place near the triple point at approximately 0.65 MPa and -50°C. These criteria are identical to those of LPG ships (Aspelund, Mølnvik, & De Koeijer, 2006).

2.5 Oil recovery

Primary oil production is when oil is produced from wells under natural pressure or by means of pumps (artificial lift). Secondary oil production is when water flooding is used to push the oil through the reservoir to the well. Injection of hydrocarbons (e.g. natural gas) to maintain pressure is considered as secondary recovery (Alvarado & Manrique, 2010). EOR (sometimes referred to as tertiary recovery) is a technique to extract oil from the reservoir, when primary and secondary recovery techniques are exhausted (Element Energy, 2012; Hook, 2009). EOR techniques can be categorized into thermal, gas injection, chemical injection and other as shown in Figure 2-3.

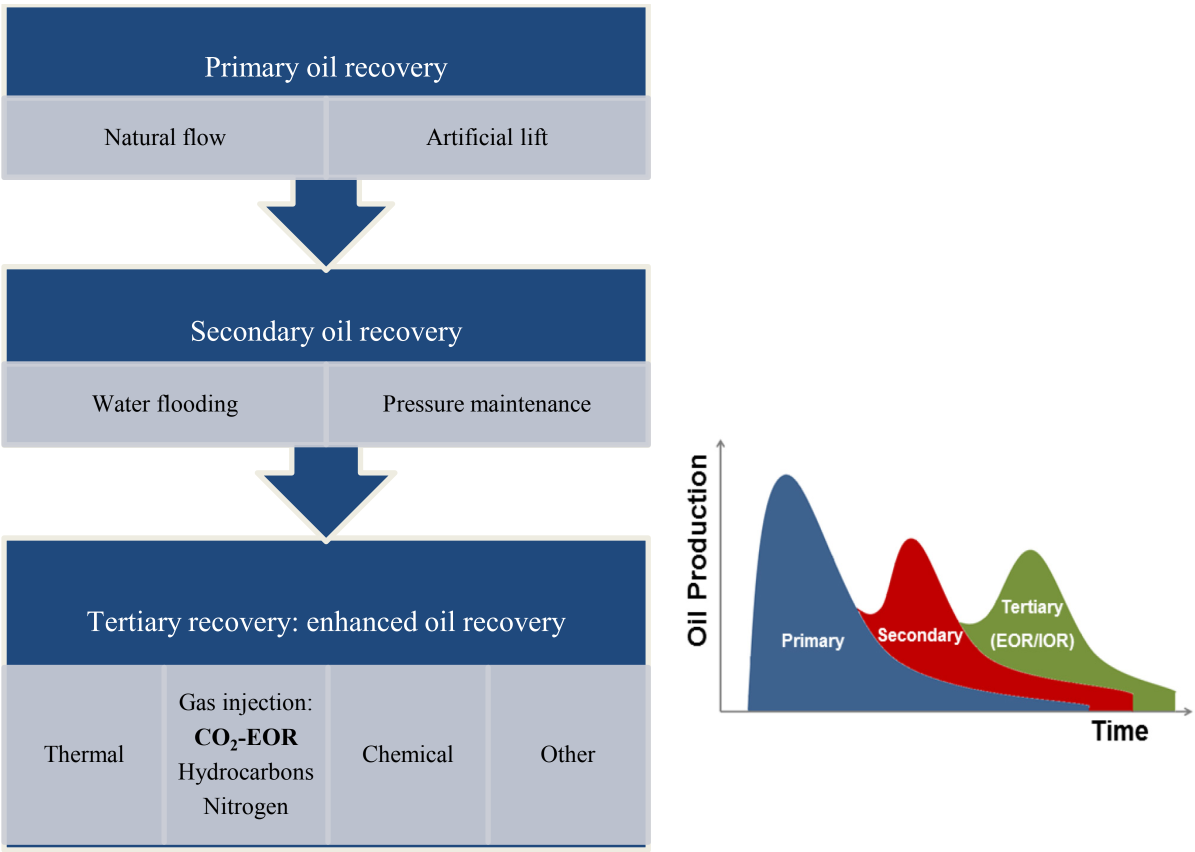

Figure 2-3: Left: overview of technology categories for primary, secondary and tertiary recovery. Right: primary, secondary and tertiary recovery over time. IOR = improved oil recovery. Adapted from Element Energy (2012)

The typical profile of oil production over time starts with little production of oil and builds up to a peak or plateau. Then, the production declines until the oil field is abandoned, i.e. the moment when the oil production has reached the bottom economic limit. Figure 2-4 shows a typical production profile of primary production.

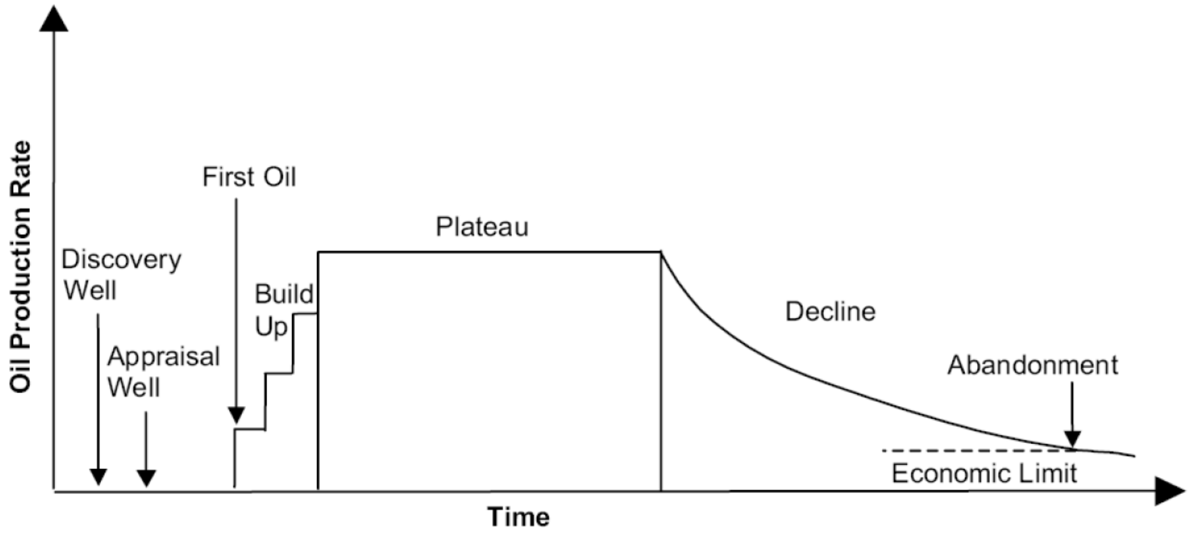

Figure 2-4: Typical production profile (Robelius, 2007)

The decline rate can be simulated using several types of fitting curves. Arps (1945) used decline rate analysis with simple mathematical fitting curves such as exponential, harmonic and hyperbolic functions to make projections for oil recovery once the production started to decrease. Since then, several scholars have used decline curve analysis using simple mathematical fitting curves (e.g. Fetkovitch, 1980; Hook, 2009).

2.6 Injecting CO_2 for improved oil production: CO_2-EOR

CO_2-EOR can be applied using water-alternating-gas (WAG) injection schemes, i.e. hydrocarbons, nitrogen or CO_2 is alternated with water flooding. Gas injection has been most widely used for light, condensate and volatile oil reservoirs. CO_2-EOR is a process in which high pressure CO_2 is injected into an oil-bearing stratum. This study focuses on miscible CO_2-EOR[12], a gas injection method for oil recovery. The miscibility of the CO_2 and the oil determine the oil displacement. The ratio of the mixture largely depends on reservoir temperature, pressure and oil composition (Advanced Resources International, 2010). Figure 2-5 provides a schematic overview of the CO_2-EOR process.

[12] Immiscible displacement CO_2-EOR yields lower recoveries compared to miscible conditions (Heddle et al., 2003)

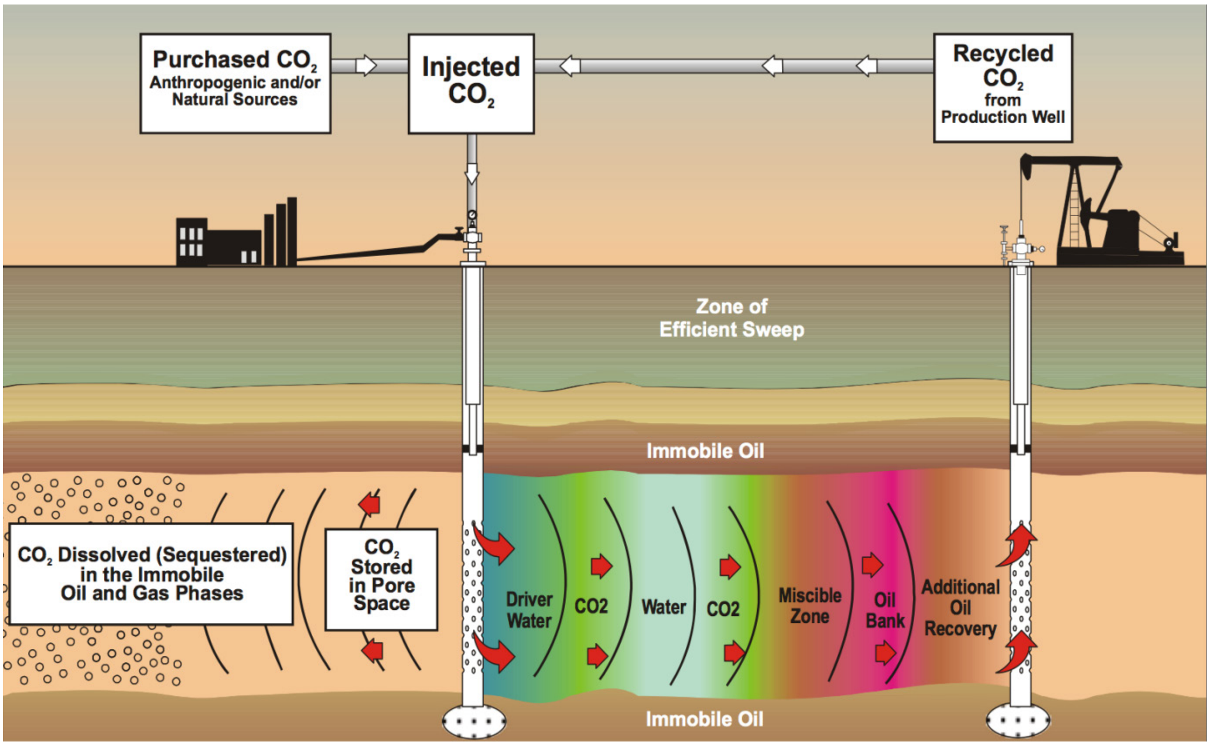

Figure 2-5: Schematic overview of CO_2-EOR (Advanced Resources International, 2010)

CO_2 is supplied from an anthropogenic (e.g. power plant) or natural source (natural occurring CO_2) and transported to the injection well. CO_2 can be alternated with WAG injection to overcome the problem of high CO_2 mobility that would greatly reduce the effectiveness of CO_2 injection. Water is less mobile than CO_2 and hence the sweep efficiency is improved (Heddle, Herzog, & Klett, 2003). The reservoir fluids become miscible, resulting in low viscosity, enhanced mobility and low interfacial tension (Lee & Kam, 2013). CO_2 acts as a propellant, and, because it reduces the viscosity of the oil, as a solvent. The oil is remobilized and is displaced to the oil production well (Advanced Resources International, 2011). The oil is accompanied by substantial amounts of CO_2. The CO_2 can be separated from the oil, dried and re-injected in the reservoir. The recycling of CO_2 will reduce the demand for fresh CO_2. The injection and production wells form a well pattern. For large onshore oil fields, there may be hundreds of wells (McCoy, 2009). The amount of CO_2 that is used for CO_2-EOR varies per project, according to size, injection rates and other economic considerations, such as the price of CO_2 (Advanced Resources International, 2010). Geology is also a dominant factor, because it determines the optimization possibilities to a large extent.

2.7 Experience and previous CO_2-EOR case studies

The uptake of CO_2-EOR projects in the Unites States in the 1970s can be explained by the abundant and cheap CO_2 from natural sources, and the readily available CO_2 pipeline systems (Alvarado & Manrique, 2010). The increase in oil market prices in the 1970s encouraged the development of this infrastructure (US Chamber of Commerce, 2012). The technology used for CO_2-EOR is commercially proven and applied in more than 75 sites around the world, most of them in the US. Other sites are in

Trinidad, Turkey and Canada (Shaw & Bachu, 2002). In the US, 13,000 CO_2-EOR wells are producing 245,000 bbl[13] per day (NEORI, 2012), or 3% of US domestic oil production (EIA, 2012).

Onshore CO_2-EOR has led to a variety of feasibility studies and pilot projects in the shallow waters of the Gulf of Mexico and the bays of Louisiana. These pilot projects are all conducted in the 1980s and include Quarantine Bay (32 ktonne CO2/y, 7.4 bbl oil/tonne CO_2[14]), Timbalier bay (no information), Bay St. Elaine field (31 ktonne CO_2/y, 5.8 bbl oil/tonne CO_2), Weeks Island Field (2.4 bbl oil/tonne CO_2, incremental recovery 260,000 bbl) and Paradis field (no information) (US Department of Energy, 2014). A recent study about the Gulf of Mexico shows a potential of 15,000 M bbl of additional oil recovery and storage of 3.9 Gt of CO_2 (US Department of Energy, 2014).

EOR has been used in 18 projects in the North Sea. However, all these projects used hydrocarbon gas to inject, instead of CO_2 (US Department of Energy, 2014). There are some CO_2-EOR projects that have been considered for the North Sea: Draugen and Heidrun Oil Fields, Don Valley Project, Miller oil fields, Tees Valley and Danish oil fields. All these projects were technically feasible but economically not viable yet. Successful feasibility studies were conducted in the South China Sea (US Department of Energy, 2014). Adequate CO_2 injection rates and increased oil production is confirmed. In Malaysia, significant increased oil production was demonstrated and field wide applications was recommended but is not yet implemented (US Department of Energy, 2014).

2.8 Oil production profiles for CO_2-EOR

Figure 2-6 shows a conceptual oil production and CO_2 injection profile for a CO_2-EOR project. In the first year, all CO_2 needs to be transported to the CO_2-EOR project and injected into the oil field. The amount of injected CO_2 is increased and the oil production follows. Production of oil usually starts after 18 to 24 months of CO_2 injection (Advanced Resources International, 2011). The amount of injected CO_2 is increased and the oil production follows. The CO_2 that is produced can be dried, recompressed and re-injected into the well, thereby lowering the demand for 'fresh' CO_2. For these processes, CO_2 recycling facilities are required to separate, dehydrate and recompress the CO_2.

Accurate numbers about CO_2 recycling are difficult to obtain because the amount of CO_2 that is bought (fresh CO_2) is often protected by a confidentiality agreement (Melzer, 2012). Shaw & Bachu (2002) estimate that 25-50% of the total CO_2 injected volume is required for purchase, while US Department of Energy (2008) states that in general about 5-6 thousand cubic feet (0.26-0.32 tonnes) of purchased CO_2 per bbl oil is used and stored, and that in total 5-10 thousand cubic feet (0.26-0.52 tonnes) of CO_2 per bbl oil is required. The oil production reaches a peak and declines until the point of economical production shutdown, usually after 10-15 years. In this thesis, the CO_2 that is not produced is assumed to be stored in the reservoir.

[13] One barrel of oil is 42 US gallon (approximately 159 liter)
[14] The volumetric number (MCF = 1,000 cubic feet) is translated to mass (tonnes) using the conversion factors by US Department of Energy (2010): 19.25 MCF = 1 tonne of CO_2.

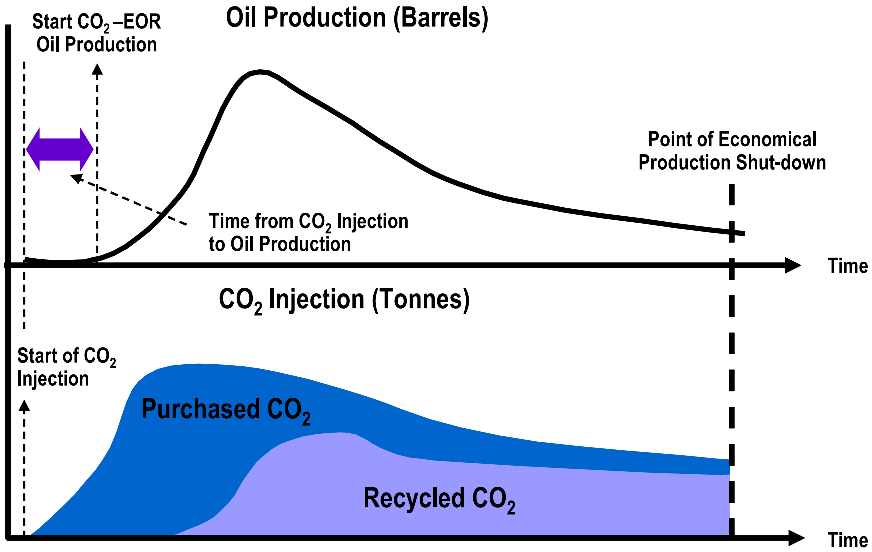

Figure 2-6: Conceptual CO_2 injection profiles and oil production, from Bellona (2005) in Advanced Resources International (2011)

3 Literature review CCS infrastructure and CO_2-EOR modeling

This chapter provides a review of the current literature on modeling CCS infrastructure. The context of the techno-economic simulator used in this study is clarified, by discussing the key features and shortcomings of current CCS infrastructure models.

3.1 CCS infrastructure modeling

The state-of-the-art CCS infrastructure simulation models are set up as linear optimizations where cost minimizing actors choose to equip capture facilities and where to develop CO_2 storage sites, routes and capacities for CO_2 transport (Mendelevitch, 2014).
McCollum & Ogden (2006) estimated the engineering requirements of compression, pipeline transport and injection and storage of CO_2. Middleton & Bielicki (2009) take a step further and developed SimCCS in which each step in the CCS chain is modeled and economies of scale play a significant role (Kuby et al., 2011). However, the availability of the CO_2 sources and sinks are not matched over time (Van den Broek et al., 2010). Moreover, the cost and capacity coefficients are assumed to be certain, resulting in a perfect foresight model. Mendelevitch, Herold, Oei, & Tissen (2010) developed a scalable, multi-period cost minimizing CCS network model for Europe (CCTS-Mod) based on SimCCS. The model uses perfect foresight for technology developments and CO_2 market prices. Herold, Rüster, & Hirschhausen (2011) updated the input data and refined the scenario analysis of SimCCS. Van den Broek et al. (2010) incorporates both temporal and spatial aspects in the planning and designing of infrastructure for CCS. Insights are provided to support policy makers by giving blueprints over time but site-specific geological data was missing. Morbee, Serpa, & Tzimas (2012) use a clustering algorithm to optimize infrastructure over time. Their major shortcoming is the requirement for endogenous inputs for the amount of CO_2 captured at every network node, resulting in the inability to assess the deployment of the complete CCS infrastructure (Mendelevitch, 2014). Piessens et al. (2012) developed an ad hoc techno-economic simulator[15] for the complete CCS chain, which is the only simulator incorporated the concept of limited foresight. CASTOR investigated a strategy to develop a large-scale CCS infrastructure. Spatial aspects were included by clustering sources and sinks (CASTOR, 2008). No specific pipelines were modeled and the infrastructure in general was pre-determined by user input (Van den Broek et al., 2010). The CO_2Europipe used the output of the PRIMES energy model for CO_2 captured and is modeled on the assumption that CCS will play a significant role in the reduction of CO_2 emissions (CO2 Europipe, 2009; Neele, Mikunda, Seebregts, et al., 2013). The ARUP study also provides insights into the large-scale deployment of CCS networks (European Commission, 2010), but lacks the spatial element (Kjärstad, Morbee, Odenberger, et al., 2013).

3.2 CO_2-EOR modeling

Most of the previously discussed models address CO_2-EOR in a highly simplified manner or not at all. However, there are several ad-hoc case studies about CO_2-EOR. Middleton, Bielicki, Keating, & Pawar (2011) conducted a case study for CO_2-EOR in the US Gulf Coast Region. The CO_2 was

[15] More on this model in chapter 4

supplied from the refinery sector. The infrastructure development mainly responds to the CO_2 market price and which EOR projects could balance the costs of CCS and CO_2 credits. Holt, Lindeberg, & Wessel-Berg (2009) assessed 48 fields in the UK and Norwegian sector of the North Sea for CCS and CO_2-EOR. The level of detail enabled modeling for each individual field. A limitation of this study is that a fixed amount and price for CO_2 are assumed (Mendelevitch, 2014). Kemp & Sola Kasim (2012) analyzed the cluster development of CO_2-EOR in the UK sector and focused on the economics by using net present value calculations. Therefore geological uncertainty is disregarded and no real option analysis can be used. Klokk et al. (2010) also uses NPV calculations, with 5 CO_2 sources and 14 potential CO_2-EOR fields in the Norwegian sector of the North Sea. Noteworthy, CO_2-EOR performance is penalized when the project operation is delayed (Mendelevitch, 2014). All models show positive system-wide NPVs for the modeled scenarios for a CCS network, except for King et al. (2013). This is a case study conducted in the Texas Gulf Coast.

A recent study that incorporates techno-economic, spatial and temporal aspects and also includes CO_2-EOR is Mendelevitch (2014). He argues that existing models assume a central planner that organizes the deployment of CCS technology in cost minimizing ways. Therefore, he proposes a model to simulate the potential development of CCS infrastructure and assesses the role CO_2-EOR can play in early deployment of CCS by introducing a CO_2 trader. The CO_2 trader is a governmental authority that prohibits or incentivizes e.g. CO_2 reductions, minimizing onshore storage or cross-border CO_2 flows. Individual CO_2 sources can make a decision either to purchase CO_2 certificates or to invest in a capture facility. The CO_2 certificates are priced based on an exogenous scenario. The governmental authority makes agreements with a transmission system operator (TSO) to develop and operate a CO_2 transport system of pipelines and/or ships. The TSO is compensated by a fee. The governmental authority sells the CO_2 to an offshore operator that can make a decision either to store the CO_2 or use the CO_2 for EOR. The complete CCS chain benefits from the revenues. As described by Von Hirschhausen, Herold, & Oei (2012), there is a gap between model results and actual development of CCS technology because of overly optimistic cost reductions and technological progress underlying the models. Mendelevitch (2014) takes note of this but still shows that all potential in the North Sea is fully exploited in all his modeling scenarios. This emphasizes the potential of CO_2-EOR but does not provide an answer to the delay in private investments for CO_2-EOR.

Table 3-1 gives an overview of the different CCS infrastructure models and whether an technical, economic, temporal or spatial aspects are incorporated. It also shows whether the CCS infrastructure model includes CO_2-EOR and whether it applies limited foresight (including uncertainty).

Table 3-1: Literature overview CO_2-EOR models

Model	**Publication**	technical aspects	economic aspects	temporal	spatial	CO_2-EOR	limited foresight
Technical models	McCollum and Ogden (2006)	■					
SimCCS	Middleton and Bielicki (2009)	■	■		■		
CCTS-Mod	Mendelevitch et al. (2010)	■	■	■	■		
CCTS-Mod (updated)	Herold et al. (2011)	■	■	■	■		
MARKAL-GIS	Van den Broek et al. (2010)	■	■	■	■		
InfraCCS	Morbee et al. (2012)	■	■	■	■		
PSS III	Piessens et al. (2012)	■	■	■	■		■
CASTOR	CASTOR (2008)	■	■	■	■		
CO_2Europipe	CO2 Europipe (2009)	■	■	■	■	■	
ARUP	European Commission (2010)	■	■	■		■	
Case study US Gulf Coast	Middleton et al. (2011)	■	■	■	■	■	
Case studies UK/Norway	Holt et al. (2009)	■	■	■	■	■	
Clusters in UK	Kemp & Sola Kasim (2012)	■	■	■	■	■	
Case studies Norway	Klokk et al. (2010)	■	■	■	■	■	
Case study US Gulf Coast	King et al. (2013)	■	■	■	■	■	
CCTSAER	Mendelevitch (2014)	■	■	■	■	■	

PART B: METHODOLOGY

4 The simulator: Policy Support System (PSS)

The Policy Support System (PSS) is a a techno-economic ad-hoc CCS simulator developed at the Royal Belgian Institute of Natural Sciences by the GeoEnergy team of the Geological Survey of Belgium[16]. The original aim of PSS was to address policy-related issues regarding the future of CCS (Piessens et al., 2012), but PSS is evolving towards a comprehensive multi-technology energy simulator. This chapter provides an overview of this evolution and shows which changes were required to arrive at the results of this thesis.

4.1 Version I

Phase I of the project (PSS-Carbon Capture and Storage) aimed to demonstrate an operational version of the tool (Piessens et al., 2009). As such, PSS I was never used for quantitative reporting of actual simulations, but graphical translation of its output was used to emphasize the importance of stochastic modeling and of the transport aspects of CCS projects. The simulator was linked to a full database of up-to-date CO_2 sources and a technology database on future CCS technologies in the power sector. This database was compatible with that used by the optimization model MARKAL[17], which was used to provide the quantitative evaluation at this stage of the project (Piessens et al., 2009). PSS is written in Visual Basic for Applications (VBA) for Microsoft Access using low-level commands to optimize for performance. A bottom-up approach with a high level of detail was used to ensure the realistic simulation of project and sector wide decisions.

While the economic evaluations in PSS I were based on net present value (NPV) assessments, a required pre-calculation module for geological data, called PSS Explorer, was already based on real option principles (Piessens et al., 2009). The goal of this tool was to calculate the storage potential of geological reservoirs.

Vandeginste & Piessens (2008) developed an advanced routing module that was implemented in PSS I, which takes many technical factors into account and proved to lead to accurate pipeline dimensions and trajectories. The simulated area is divided into individual cells forming a grid (i.e. Belgium in 2.5x2.5 km grid cells). PSS uses factors to weigh the cost of a specific cell in the simulated grid. To steer the pipelines into preferred routes (corridors[18]), mock cost factors are introduced to artificially make it more costly to deviate from the corridors. The cost factors are phony, because they are only used for the routing optimization; the cost calculation itself uses the actual cost parameters. PSS is the only simulator making use of this methodology, while others are overestimating the costs for

[16] In addition to the developers of PSS, an expert group was formed to address climate change and its consequences for Belgian and international policy. The Flemish institute for technological research (VITO), the University of Liège, the University of Mons, and Ecofys are the main partners. The Belgian-Dutch collaboration was intensified which resulted in an extensive implementation of Dutch storage options, because it was embedded in the Dutch CATO-2 project. CATO (Dutch abbreviation for CO_2 capture, transport and storage) is a demand driven R&D program which focuses on facilitating and enabling integrated development of CCS.

[17] MARKet Allocation. See Seebregts, Goldstein, & Smekens (2001) for an extensive overview of the MARKAL family

[18] e.g. Buisleidingenstraat, a 75 km pipeline passage to connect Rotterdam and Antwerp

deviating from corridors[19]. Moreover, it uses vector data for hinder factors such as infrastructure that imply additional crossing costs, providing a resolution that is much higher than that of the underlying raster.

The parameters are defined as stochastic parameters with an uncertainty distribution ('inner Monte-Carlo'): a normal, lognormal or uniform (block) distribution. The repetitive character of setting these values at random in a specified uncertainty distribution is called Monte Carlo analysis. True random data from atmospheric noise (160MB) is used to set values for the stochastic parameters in each Monte-Carlo iteration. Perfect foresight is avoided to guarantee a more realistic approach: the future path can deviate from the set values in the Monte Carlo iteration. In short[20], investment decisions are not perfect, because the outcome is not already known which is the case for perfect foresight models. Each project decision is made based on its own future projections, with information available at that time. The actual future parameter may be different, but are only revealed when simulation reaches that future point in time. This results in more realistic investment risk assessment.

4.2 Version II

PSS II updated the already available datasets and included descriptive data about current capture potential and technologies (Piessens et al., 2012). Real option analysis was expanded to replace the NPV project evaluation in the economic calculations in the 'inner Monte Carlo' loop in PSS. The outcome of the real options analysis is used as input for a project decision system that is based on the modern portfolio theory. The latter is based on the concept of diversification in investments to maximize expected return from the portfolio, for a given amount of portfolio risk (Houge & Westlie, 2011; Sanders et al., 2013). In this way, a more realistic investment decision is simulated, i.e. taking into account the benefits of spreading risks.

4.3 Version III

The main contribution of PSS III was the inclusion of renewable energy technologies, which was required to allow running PSS separately from TIMES/MARKAL[21] (Piessens et al., 2012). Renewable energy technologies are treated in a similar way as power plants in the simulations. For instance, biomass production is simulated as a power plant with a certain constraint to limit the areal availability for biomass production at national level.
Furtermore, PSS III added functionality required for the assessment of CCS in Kazachstan, Sweden and Austria.

4.4 Towards version IV

The simulation of CO_2-EOR activities was not yet integrated in PSS III, the working version at the start of this thesis. In order to allow for the peculiarities of CO_2-EOR projects to be correctly assessed,

[19] For instance, Van den Broek et al. (2010) use a terrain factor 1.5 when the pipeline is not following a corridor. Thereby, the pipeline is steered into the corridor because it uses a least-cost route optimization. However, this could also result in an unrealistic increase in costs when a corridor cannot be followed. PSS avoids this by using the phony cost factor.
[20] Piessens et al. (2012) and Welkenhuysen, Ramírez, Swennen, & Piessens (2013) provide an elaboration on the pitfalls of using perfect foresight in simulations
[21] Techno-economic models for energy systems. See also footnote 17

PSS IV was developed in parallel with this study by Kris Piessens and Kris Welkenhuysen of the Geological Survey of Belgium. The main difference between CO_2-EOR and CCS is the goal: CCS is aimed at storing CO_2 while CO_2-EOR is aimed at extracting more oil from a field. Moreover, they differ in terms of the role that CO_2 plays, the factors influencing operation and the complexity. A brief overview of how CO_2-EOR activities are evaluated in PSS IV is outlined below.

PSS basically matches CO_2 sources with suitable sinks based on economic criteria and feasibility. The similarity between CO_2-EOR and standard CCS projects is the requirement to transport large quantities of CO_2. However, the economic decisions in CO_2-EOR projects are fundamentally different, because the production of incremental oil is an important economic motivation, next to the benefits of geologically storing CO_2. Somewhat simplified, most CO_2-EOR projects use CO_2 primarily to boost oil production, while CCS regards CO_2 as undesired by-product that needs to be isolated from the atmosphere. Hence, the CO_2 requirements in CO_2-EOR projects are defined by the CO_2 demand side (optimizing for incremental oil recovery), while standard CCS projects focus on the CO_2 production side (storing all captured CO_2).
The selection criteria for a suitable location differ; because CO_2-EOR is used in oil and gas fields that are typically nearing depletion, while this aspect of timing is absent in many standard CCS locations (e.g. saline aquifers) where screening will first of all focus on sufficient storage capacity, etc.
The value of CO_2-EOR projects is intrinsically also more complex to assess than simple CO_2 storage projects, because of the relation to primary oil recovery, CO_2 production to the surface and the influence of CO_2 recycling on the external CO_2 demand.

Stylized CO_2-EOR locations in the North Sea are used for the simulations in this study. Consequently, adequate CO_2 transport modes have to be selected. Development of PSS IV therefore involved extending the cost databases and routing module of PSS to allow simulating offshore pipelines and ship transport. Offshore pipelines are relatively more expensive per kilometer for short distances than for longer distances, when compared to onshore pipelines. In addition, the water depth influences the costs for offshore pipelines. These two are factored in using cost multipliers and terrain factors. Ship transport is included by a price for CO_2 per tonne and a scale factor for distance.

Especially in offshore CO_2-EOR projects, transport of CO_2 is an important cost factor. Therefore, the transport infrastructure systems and their use have to be optimized. For the economics of a CO_2-EOR project, utilization of full capacity of the CO_2 transportation mode is desirable. A buffer (i.e. intermediate storage) can guarantee this continuous flow while using an intermittent CO_2 transportation mode such as a ship. Project flexibility (i.e. moving from one field to another) can optimize the CO_2 transportation capacity.

PSS IV simulates CO_2 storage in CO_2-EOR projects using an approach that is modified from Welkenhuysen, Ramírez, Swennen, & Piessens (2013). Multiple techno-economic parameters are added to include CO_2-EOR aspects such as EOR ratio, recycling ratio and oil market price. For these parameters, the time aspect is essential. These parameters are extensively discussed in part C. Table 4-1 summarizes the major changes from PSS III to IV.

Table 4-1: Evolution from PSS III to PSS IV

PSS III	**PSS IV**	**Required information**
CO_2 capture	CO_2 supply	CO_2 capture cost curves
Onshore pipeline transport	Offshore pipeline transport Ship transport	Offshore terrain factors Ship cost metrics
Real option valuation	Real option valuation	Real option valuation
Storage reservoirs	EOR production CO_2 recycling	EOR characteristics CO_2 injection/production dynamics

5 Methodology

To improve the valuation method of CO_2-EOR projects, this thesis proposes a methodology based on real option analysis. Uncertainties of multiple CO_2-EOR fields are included in the project valuation. Techno-economic parameters are included for these CO_2-EOR projects. PSS is used as the techno-economic simulator to valuate multiple CO_2-EOR projects and simulate the investment decisions. Investment decisions are taken from a company or investor's point of view (e.g. the CO_2-EOR operator).

The thesis is based on a desk study at Utrecht University and the Royal Belgian Institute of Natural Sciences. A methodology and case study was established to advance from PSS version III to run simulations for CO_2-EOR in PSS version IV[22], with the goal to run simulations for CO_2-EOR. The code development of PSS itself was done by Kris Piessens and Kris Welkenhuysen from the Royal Belgian Institute of Natural Sciences.

This chapter provides an overview of the methodological framework. First, an introduction about the generic CO_2-EOR case study is given, followed by the three steps of the CO_2-EOR chain from the (1) CO_2 hub, (2) transported by pipeline and ship to the (3) CO_2-EOR project. At last, the valuation method is elaborated on.

5.1 Simulation using a generic case study

A generic case study is developed, based on data from the North Sea. CO_2 is supplied from four industrial areas around the North Sea (Esbjerg, Teesside, Rotterdam, and Antwerp) from where it is transported by ship or pipeline to a cluster of seven potential CO_2-EOR projects. In the model, a cluster of seven oil fields is constructed based on actual data and results from simulations in other studies of three existing oil fields. The uncertainties and flexibility are included by stochastically simulating the performance of these projects.

Figure 5-1 shows a schematic map of the hexagonal configuration of the CO_2-EOR cluster in the North Sea basin, with potential pipeline connections to four CO_2 sources.

[22] Chapter 4 extensively describes the evolution from PSS version III to version IV

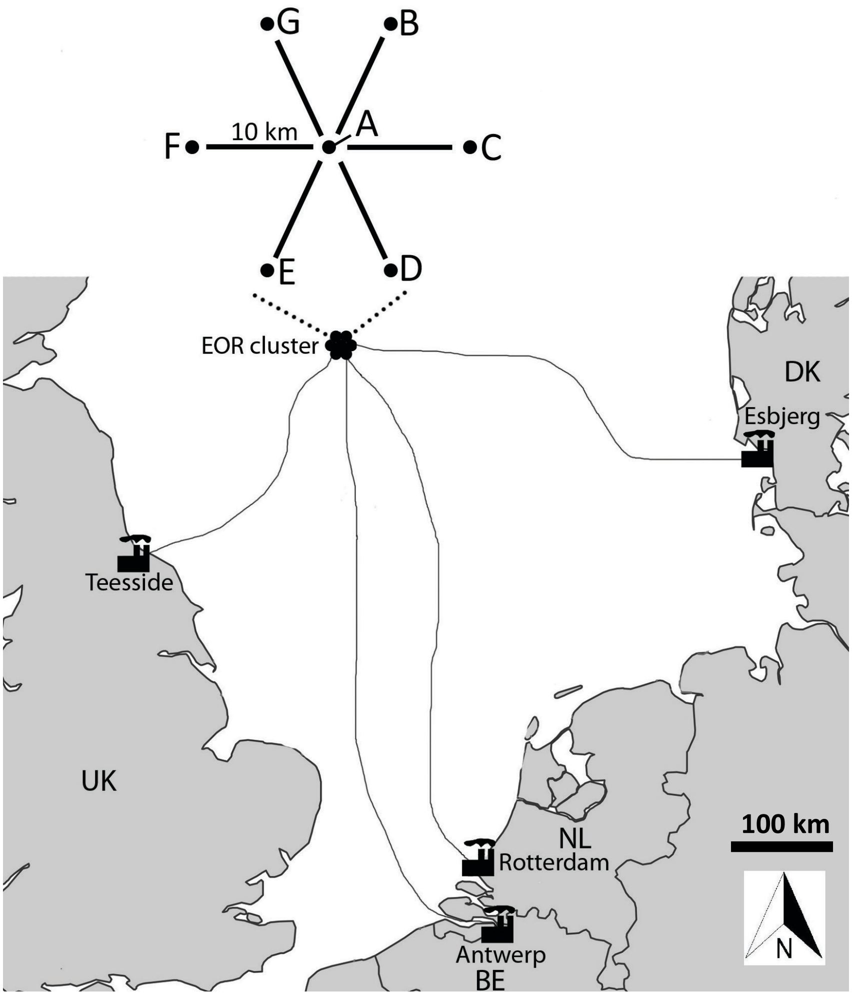

Figure 5-1 North Sea map for the simulation. The black lines represent a simplified possible transport connections between the four CO_2 sources and the EOR cluster. Ship transport is also evaluated for CO_2 transport. The cluster is consisting of 7, at this scale closely packed, potential CO_2-EOR projects.

A general overview of the steps in the CO_2-EOR chain is depicted in Figure 5-2. The first step is to capture the CO_2 at an industrial facility (e.g. a power plant). The second step is to transport the CO_2 from where it is captured by pipeline or ship to the CO_2-EOR cluster. The last step in the chain is the CO_2-EOR project where the incremental oil is produced.

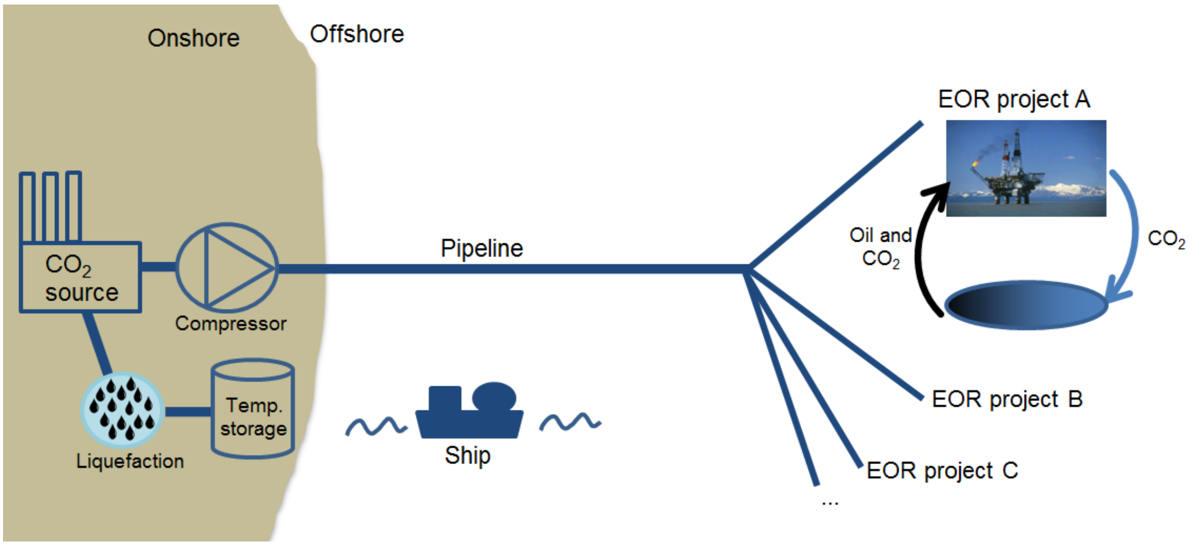

Figure 5-2: CO_2-EOR chain from CO_2 source via either compressor and pipeline, or temporal storage, liquefaction and ship to the CO_2-EOR projects

5.2 CO_2 hubs

The generic CO_2 hub locations are established based on CO_2 emissions from large point sources in the North Sea area and whether construction of pipelines is possible and existing harbor infrastructure can be used.

5.2.1 Locations

The hubs represent industrial clusters in a port region. Four hubs are selected for the simulations in this thesis. The Antwerp region is a major source of CO_2 emissions in Belgium. The Rotterdam Climate Initiative in the Netherlands intends to create a CO_2 hub for the North Sea region (Rotterdam Climate Initiative, 2008, 2011). The coordinates of the location is obtained from the proposed locations in Rotterdam Climate Initiative (2011). The Teesside Low Carbon project, formerly known as the Eston Grange, is a CCS project under development since 2006 (Teesside Low Carbon, 2012). For this simulation, Teesside has been selected as the location of a UK CO_2 hub over the gas terminal at St. Fergus. Although this gas terminal is suitable as CO_2 hub, it is located further to the north which would drastically increase the size of the modeled region. In Demark, most of the CO_2 sources are in the east side. To reach the CO_2-EOR cluster in the North Sea, a location on the west side of Denmark is favorable. The Esbjerg power plant is located in the west side. The power plant is a large point source for CO_2 emissions (2 Mt/y; ZeroCO2, 2014). The power station is proposed for a pilot CCS project. There is also an other power plant nearby. It is near the Port of Esbjerg and there are existing pipelines in the north of Esbjerg which suggests that the area is suitable as a starting point for the construction of an offshore pipeline.

5.2.2 Cost curves for CO_2 sources

The costs for capturing a quantity of CO_2 is represented in a capture cost curve. These curves are constructed based on data for the CO_2 sources present at the four locations. Each hub has its own capture cost curve. The cost curves show the price (€/tonne CO_2) for cumulative captured CO_2.

The Antwerp capture cost curve is constructed based on a confidential report on CO_2 emission data for point sources in the Antwerp region. For Rotterdam, Teesside and Esbjerg, the European Pollutant Release and Transfer Register (European Environment Agency, 2012) is used. Large point sources in the petrochemical, chemical and power sector are selected for the four hubs. The cost figures for the chemical and petrochemical CO_2 sources are derived from Kuramochi, Ramírez, Turkenburg, & Faaij (2012) in which the capture cost range from €30-60/tonne CO_2 depending on the chemical process, type of plant and capture technology. For power plants, the capture costs range from less than €30/tonne CO_2 for lignite-fired power plants, to just over €30/tonne CO_2 for hard coal and €80/tonne CO_2 for natural gas fired power plants (ZEP, 2011b). At first, the lowest price of CO_2 is addressed, moving along the curve as demand increases. Costs are transformed in $€_{2010}$, unless stated otherwise. The costs are not harmonized. The capture costs include compression to 110 bar.

5.3 CO_2 transport

Next, the CO_2 needs to be transported to the CO_2-EOR project. Transport by road (i.e. car tankers) is excluded from this study, because it is not used for industrial sized projects.

5.3.1 Pipeline transport

Transportation in PSS III is modeled based on actual and average project needs with a least-cost functions using onshore pipelines as carrier. For CO_2 transport by offshore pipeline in PSS IV, a comprehensive literature review was done, followed by a comparative analysis between offshore and onshore pipelines. Moreover, other factors influencing the costs for offshore pipelines were mapped and quantified. The search strategy focused on peer-reviewed articles obtained through Google Scholar, the Oil & Gas Journal and grey literature from CATO[23], the US Department of Energy, the European Commission and other reports from commercial parties and research consultancies. The keywords for searching are listed in Table 5-1.

Table 5-1: Search keywords for offshore pipelines

Search keywords	Keyword variation (e.g.)
"Offshore pipeline*"	Subsea pipeline*, trunkline*
"Pipeline* engineer*	
"Oil and gas" pipeline*	"CO_2 pipeline*"
"Terrain factor*" pipeline*	"Topographic difference*" pipeline*
"Cost factor*" pipeline*	CAPEX pipelines

Asterisk (*) is used as wildcard, quotes ("") are used for exact wordings

This results in two factors describing the offshore pipeline costs as compared with onshore pipeline costs as modeled in PSS. These two factors comprise all additional costs for offshore pipelines, such as the thickness of the pipelines as well as the requirement for booster stations. The two factors are dependent on water depth and the length of the pipeline (i.e. short offshore pipelines are relatively more expensive on short distances than for longer distances, compared to onshore pipelines). Figure

[23] CATO (Dutch abbreviation for CO_2 capture, transport and storage) is a demand driven R&D program which focuses on facilitating and enabling integrated development of CCS in the Netherlands.

5-3 shows the simplified methodology for transforming an onshore pipeline model to offshore pipeline costs. This cost transforming process is extensively described in chapter 0.

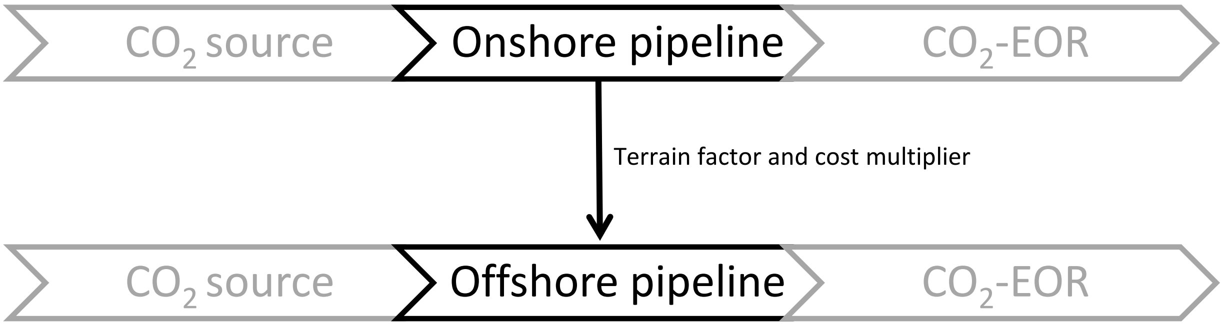

Figure 5-3: Simplified methodology of transforming an onshore pipeline model to offshore pipeline costs using a terrain factor and cost multiplier

5.3.2 Ship transport

Ship transport is potentially cost-competitive with pipelines. It has the advantage of increased flexibility, the possibility to change loading and unloading locations, lower capital expenditure and reduced financial risk because the ships have residual value for hydrocarbon transportation (CATO2, 2013a; ZEP, 2011b).

For CO_2 ship transport, pre-calculated data in €/tonne CO_2 was acquired from previous detailed studies. Scenarios and data are used from reports from CATO (CATO2, 2013a, 2013b). These numbers are elaborated on in section 7.4.

5.4 CO_2-EOR

Techno-economic parameters need to be established for the seven oil fields in the generic cluster in the North Sea. The production profile (i.e. annual oil production) is relevant for the primary oil production simulation and CO_2-EOR. The CO_2 profile (annual CO_2 injection, annual CO_2 production, recycling rate, moment of CO_2 breakthrough) are also important for CO_2-EOR.
To make the simulations realistic, actual data from offshore oil fields are used and adapted to construct the seven oil fields. The offshore oil fields Claymore, Fulmar and Forties are selected in this thesis because of their size, their production maturity and available information. All three are oil fields located in the UK sector of the North Sea. Maturity of oil production implies that a field is approaching the end of primary and secondary production.

The CO_2-EOR cluster is constructed as a perfect hexagon of seven fields (A-G). A small distance between the seven fields is favorable for the cluster due to economies of scale, i.e. a single trunkline can be used to supply CO_2 to the whole CO_2-EOR cluster. The actual distance between large offshore fields near each other are analyzed using data from Talisman Energy (2006a, 2006b, 2011) and 10 km proves to be likely and is therefore used as the distance between the fields in the constructed cluster. The center of the cluster is assumed to be located at the coordinates of oil field Fulmar: 56°29 N 2°8 E (UK Department of Energy & Climate Change, 2014b)

Actual oil production data is used to analyze and construct the production profiles for the constructed fields in the simulation. Monthly oil production data is obtained from UK Department of Energy & Climate Change (2014a) as well as CO_2 injection schemes based on earlier CO_2-EOR simulations from Element Energy (2012). The range of outcomes and analyses can be used as input for the simulator. Specifically for Claymore, Element Energy (2012) has provided detailed simulated production profiles for CO_2-EOR. These are used as a basis for the construction of the possible techno-economic parameters of the seven CO_2-EOR projects.

Figure 5-4 shows an example how lognormal curves are used to fit the primary production data in the declining part of the curve. The method to derive to the modeling of primary production and CO_2-EOR is more extensively described in chapter 7.

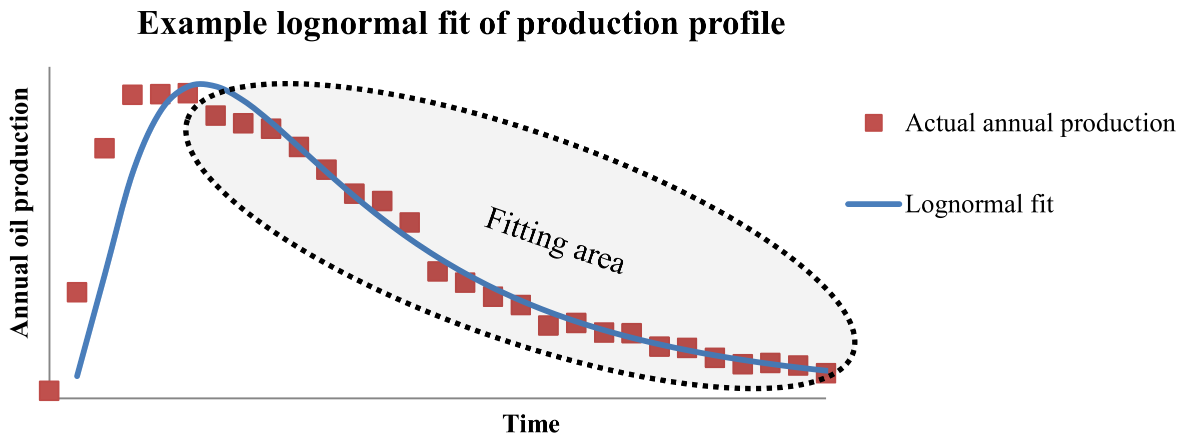

Figure 5-4: An example of using a lognormal fit of the actual production data. The mean square error is minimized in the declining area, indicated with the grey ellipse

5.5 Valuation method

The central assessment tool in this study is PSS IV, which evaluates opportunities using real options analysis. In comparison, the more traditional net present value analysis assumes an unchangeable commitment to the discounted expected cash flow that is specified when the project is initiated (Houge & Westlie, 2011). Net present value analysis neglects the inherent flexibility of projects (e.g. to defer or abandon a project) that the firm-level actor can undertake. Accordingly, projects are assumed to be always fully carried out, even when early results (i.e. more information about the geological characteristics of the EOR field) are unfavorable for further development.

Real options analysis is an economic method of valuating the right to undertake a certain business opportunity, such as the option to expand, abandon or defer a project (Berk & DeMarzo, 2014). Real options analysis is a useful method for assessing investment decisions for CO_2-EOR projects because real options can take uncertainties such as production curves and injection rates into account. Real options accredit the intrinsic flexibility of a project. The value of waiting (i.e. postponing project, or keeping the option to engage in it later) is valuable when uncertainty is beyond the control of the investor (CATO2, 2011). This is the case for the geological uncertainty for CO_2-EOR projects. Managerial decisions can enhance the upside opportunities (gains) and decrease the potential risks (losses).

The starting point for the simulated projects is primary oil production. Each year, PSS evaluates the opportunities for retrofitting the primary oil production platforms to EOR. Each Monte Carlo run, for instance the EOR recovery rate (amount of oil that is recovered during CO_2-EOR) is set between a realistic range to simulate the geological uncertainty of the reservoir (i.e. favorable recovery vs. unfavorable recovery). This approach enables it to investigate the influence of different stochastic techno-economic parameters. Transportation is modeled both by ship transport and pipeline to select the optimal mode.

When producing oil with primary production, options are to continue primary production, to retrofit to EOR or to stop primary production. When EOR becomes operational, the list of options is reduced to continue to produce oil with EOR or to stop all activities. Figure 5-5 shows an example of a real option decision scheme.

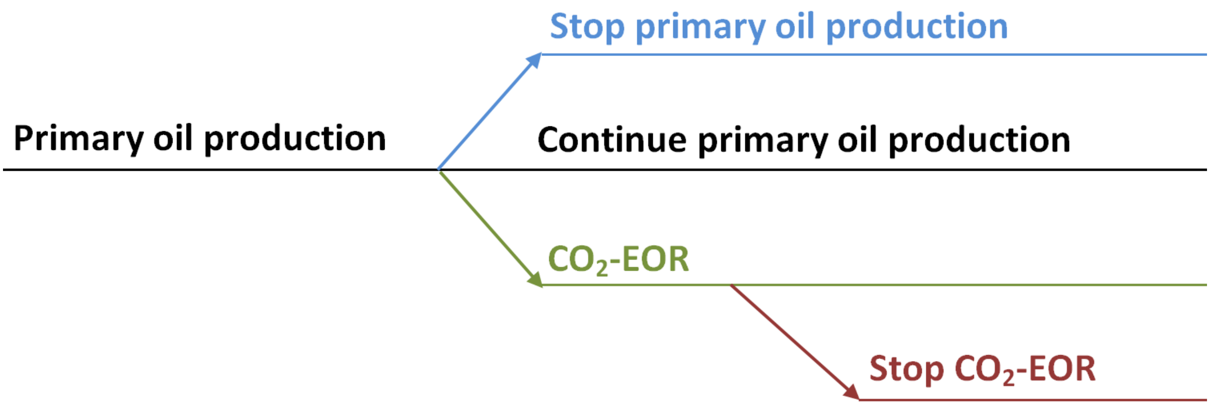

Figure 5-5: Real option decision scheme. Starting point is primary production in 2010. After each year, a decision is made based on the real option value of the status which can be Stop primary production [blue], continue primary production [black] or start EOR [green). When the primary production is retrofitted to EOR, the next decision is to continue CO_2-EOR or to stop CO_2-EOR [red]. Once a project is stopped, it cannot be operational again.

CO_2-EOR becomes operational when the real options value of the project is higher positive than that of continued primary production. Figure 5-6 shows an example of cash flows of a CO_2-EOR project. In the first years, capital is invested (capital expenses) to retrofit an oil platform for CO_2-EOR. Later, revenues are generated by oil and CO_2 credits. When the revenues exceed the operational expenses, the profit is taxed. The project can be valuated using the discounted cash flows. Decommissioning costs can be saved because the decommissioning is postponed and the costs are discounted over time.

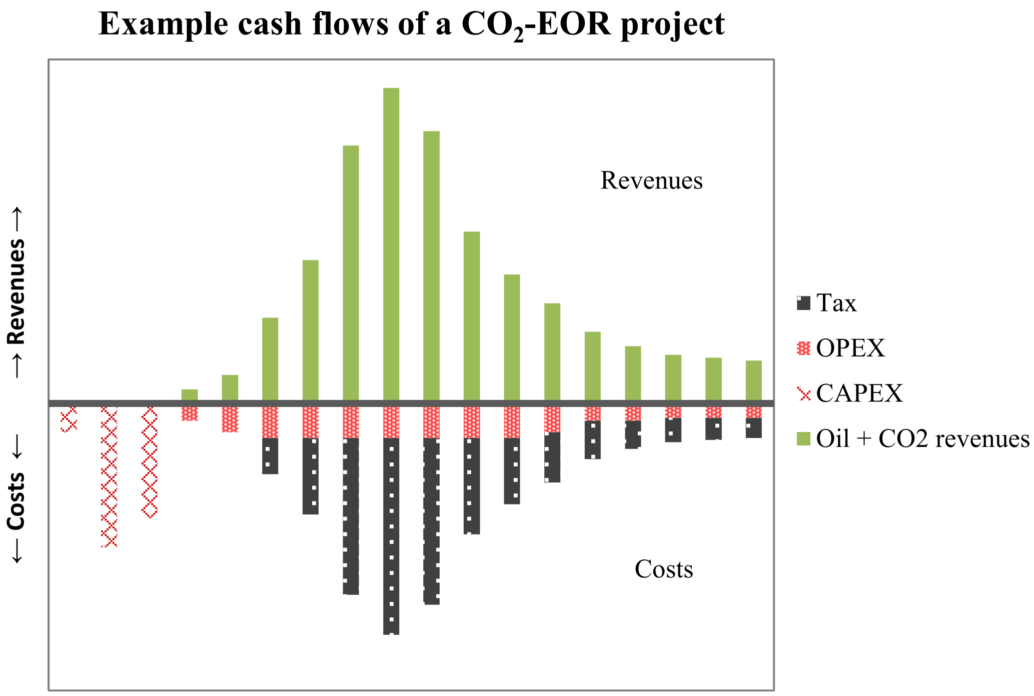

Figure 5-6: An example of cash flows of a CO_2-EOR project over time. In the first years, capital is invested (CAPEX) to retrofit an oil platform for CO_2-EOR. Later, revenues are generated by oil and CO_2 credits. When the revenues exceed the operational expenses (OPEX), the profit is taxed.

Because no costs and revenues are associated with the initial state of the platform (i.e. primary production), primary production can in theory prolong for the entire simulated period. Therefore, a boundary condition is introduced, only for simulation purposes. The boundary condition is defined as the minimum annual oil revenue. This is illustrated in Figure 5-7.

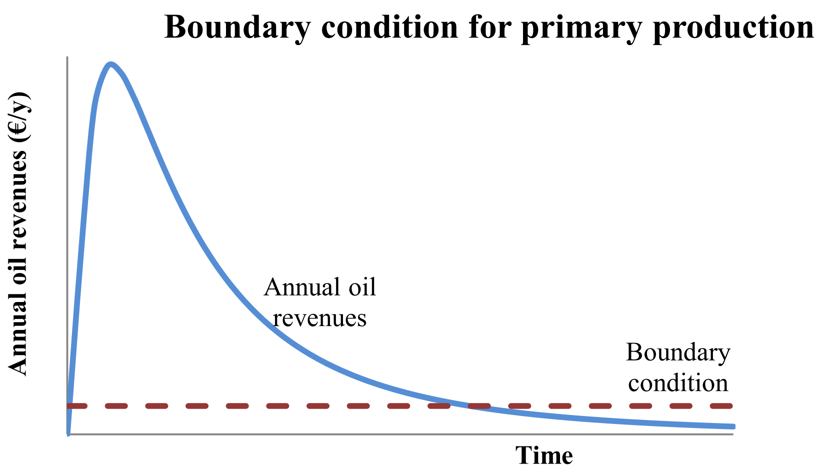

Figure 5-7: The boundary condition or "cut-off revenue" represents the moment in time when primary production is ceased. This limit is only for simulation purposes.

When the project value of CO_2-EOR is unfavorable and the boundary condition is reached, the primary production will be stopped. When this occurs in the simulation, CO_2-EOR will not be started, because CO_2-EOR would have been started when it showed a positive project value before the boundary condition was reached.

The boundary condition is calculated using the operational expenses for offshore platforms for primary production. It is assumed that the annual oil revenues must outweigh the operational expenses. Kaiser & Yu (2010) showed that primary production is ceased when annual production drops below 0.009 M bbl/y. However, this number is extremely low because it is based on US onshore data in which operational expenses are reaching 0; the daily production is only 25 barrels. Therefore, this thesis estimates the economic limit by comparing the operational expenses estimation of oil field Claymore with an estimation of revenues. The Claymore oil field is assumed to have one main platform and 29 satellite platforms, obtained from maps in Talisman Energy (2006). The operational expenses are €165M according to the annual costs for a main platform of €20M and €5M for a satellite platform (NOGEPA, 2009). By using the oil market price of the relevant year (obtained from the oil market price scenario, more on this in section 9.1.1), the minimum amount of barrels can be calculated (e.g. an oil market price of €120 implies a boundary condition of €165M / €120 = 1.375 M bbl). This number is corrected for the size (OOIP) of the other fields.

PART C: SIMULATION INPUTS

6 Input for PSS: CO_2 sources

As described in section 5.2, capture cost curves are constructed for the four CO_2 hubs in the simulation. The curves show the amount of CO_2 that can be captured at a certain cost level, sorted from the lowest to the highest costs per tonne CO_2. Rotterdam is the largest CO_2 hub of 22.4 Mt/y, the maximum of Antwerp is 16.4 Mt/y, for Teesside 6.4 Mt/y and 2.4 Mt/y for Esbjerg. The capture cost curves are shown in Figure 6-1.

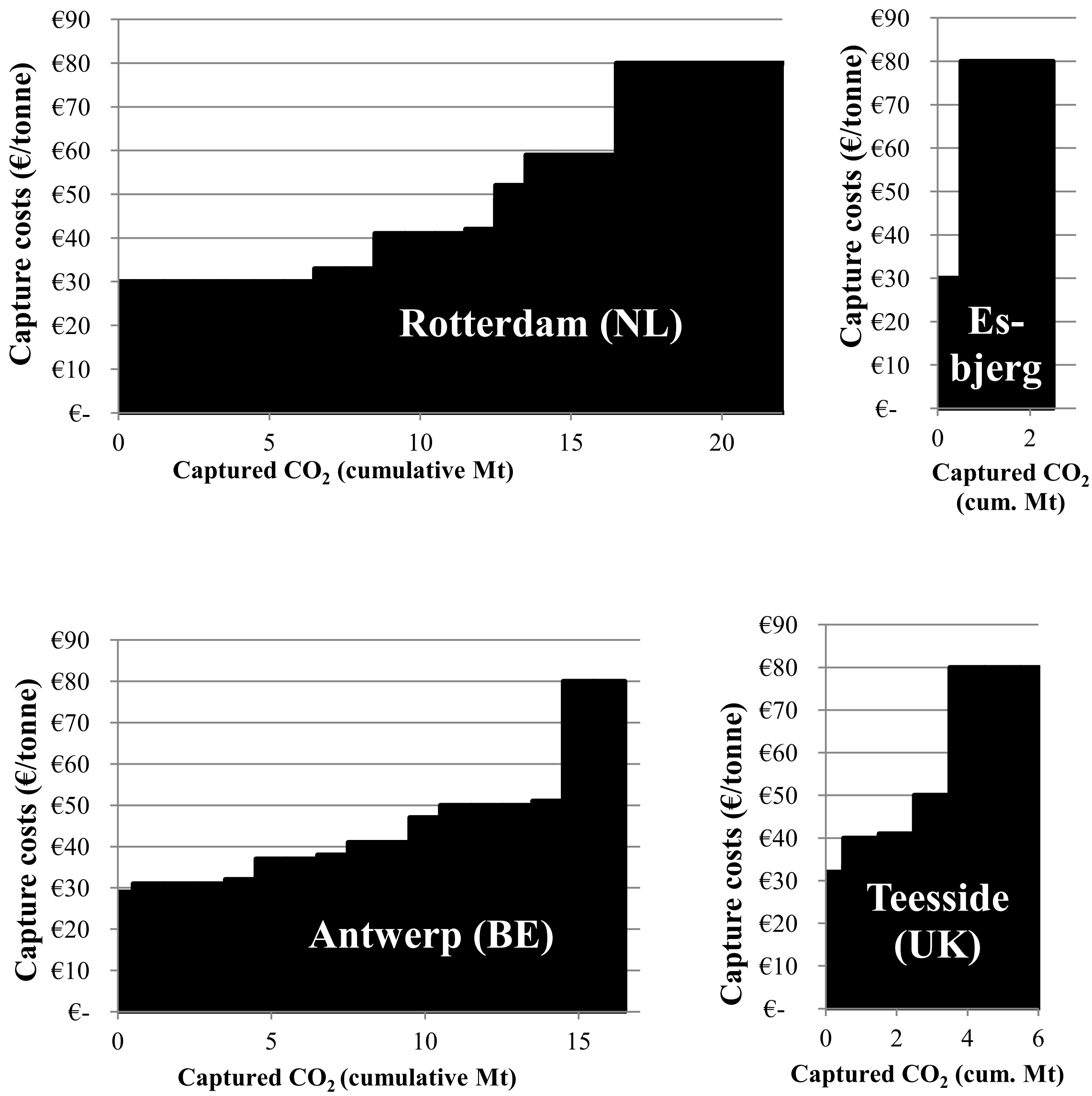

Figure 6-1: CO_2 capture cost curves for Rotterdam (NL), Esbjerg (DK), Antwerp (BE) and Teesside (UK). Each step in a curve represent an individual CO_2 source where CO_2 can be captured at a certain cost per tonne. Each curve is sorted from the cheapest to the highest CO_2 capture facility.

7 Input for PSS: transport

This chapter gives an overview of transporting CO_2 by pipeline and ship. In PSS III, CO_2 transport is modeled using onshore pipelines. Therefore, a method is used to transform the costs for onshore pipelines to offshore pipelines, by reviewing the differences in costs. These costs are transformed using factors to show the increase in costs for offshore pipelines relative to onshore pipelines. All additional cost elements are included, such as the requirement for thicker steel, but also booster stations.
Furthermore, cost components resulting in the cost figures for CO_2 transport by ship are also given in this chapter.

In this study, the starting point for pipeline investment costs are the equations embedded in PSS (Piessens et al., 2009). The material costs are calculated using pipeline length, outer diameter of the pipeline, steel costs, operational pressure, allowable stress in the pipeline and factors for under-thickness tolerance and threading, mechanical strength and corrosion. Labor costs are based on empirical data from the Oil & Gas Journal (Smith, True, & Stell, 2005; True & Stell, 2004; True, 2003) , and dependent on outer diameter and pipeline length (not in a linear way). Miscellaneous costs are based on empirical data from the Oil & Gas Journal and depend on outer diameter and pipeline length. PSS already implemented terrain factors for cost calculations. This thesis makes use of this implementation, but uses other terrain factors. For instance, a terrain factor for depth is used, instead of height differences.

7.1 Cost multipliers in literature

This literature review shows a range of cost multipliers for offshore pipelines, with regard to onshore pipelines. In this thesis, cost multipliers are referred to as terrain factors, when the value changes according to (sub-)surface properties. The cost of labor, the land use (i.e. population density) and right-of-way cost are influenced by terrain factors and can vary substantially across different areas (Knoope et al., 2013). The soil type is irrelevant for the offshore situation, because offshore pipelines are only buried when they need to be protected from e.g. fishing gear (Palmer & King, 2008).

IPCC (2005)

Cost for onshore pipelines can increase by 50-100% when the routed area is densely populated (IPCC, 2005). Offshore pipelines have a higher operational pressure and lower temperature, in comparison with onshore pipelines. Usually, offshore pipelines are 40-70% more expensive than onshore pipelines (IPCC, 2005). The transport costs in $\$_{2002}$/t CO_2 for distances ranging for annual flow rates of 1-30 Mt are digitized and analyzed. Figure 7-1 shows the high and low estimates for 250 km pipelines in $\$_{2002}$/tonne CO_2 for different flow rates.

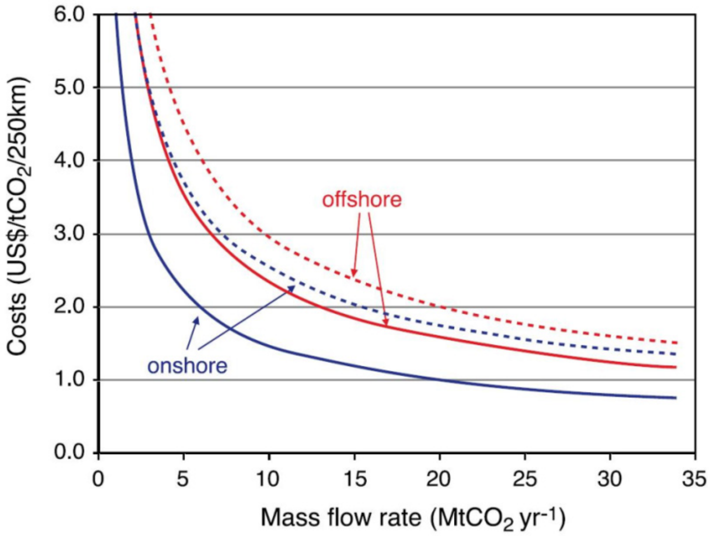

Figure 7-1: Cost ($\$_{2002}/tCO_2$) for 250 km transport (IPCC, 2005). High estimate offshore: red dotted line, high estimate onshore: blue dotted line. Low estimate offshore: red solid line. Low estimate onshore: blue solid line. Note that offshore pipelines can be cheaper than onshore pipelines, as shown in the low estimate for offshore and high estimate for onshore pipelines.

According to IPCC (2005), offshore pipelines can be cheaper (0.9 times as expensive) or twice as expensive as onshore pipelines.

Huang et al. (2008)

Huang, Rezvani, McIlveen-Wright, Minchener, & Hewitt (2008) use the non-linear regressions by IEA GHG (2002) to calculate pipeline costs for four case studies. The costs in $[24]/t CO_2 for distances ranging from 50-500 km are digitized and analyzed. The numbers show that offshore is 3.7-4.0 times more expensive than onshore. Booster stations are excluded from the offshore pipeline system. Hence, the diameter is increased to compensate for pressure losses along the pipeline.

IEA GHG (2010)

IEA GHG (2010) uses terrain factors for flat open countryside, mountainous, desert, forest and offshore terrain. IEA GHG (2010) also distinguishes different terrain factors for water depths of less than 500m and more than 500m, see Table 7-1.

Table 7-1: Terrain factors for different terrain types (IEA GHG, 2010)

Terrain	Factor
Flat	1.0
Mountainous	2.5
Desert	1.3
Forest	3.0
Offshore (<500m depth)	1.6
Offshore (>500m depth)	2.7

[24] Base year for currency not stated in article

IEA GHG (2013)

IEA GHG (2013) has published numbers based on Kinder-Morgan (a pipeline transportation company) cost metrics for different types of terrain. The costs are translated into €$_{2011}$[25] per centimeter diameter and kilometer length. Flat terrain is 0.15 M€$_{2011}$/cm/km and offshore (at a depth 3.8-5.1 meter[26]) the costs are 2.1 M€$_{2011}$. Laying pipelines offshore are usually evaded in the United States. That could be an explanation for the large difference (factor = 14) between offshore and flat terrain, Furthermore, offshore pipelines are seldom appropriate in the US situation, because the vast majority of oil and gas production and exploration are onshore, also leading to a vast increase in costs for offshore pipelines. The shallow depth in the North Sea region allows for easier offshore operations.

Heddle et al. (2003)

Heddle, Herzog, & Klett (2003) performed a regression analysis of pipeline construction cost data from True (1990, 1998). They found a cost factor of $\$_{1990\text{-}1998}$ 33,853/in/mile. For offshore pipelines, they used a case study for a 30-inch 500-km long offshore pipeline from Sarv (2001) and translated this number to a cost factor of $\$_{1990\text{-}1998}$ 57,659/in/mile[27]. Therefore, offshore pipelines are a factor 1.7 more expensive than onshore.

Van den Broek et al. (2010)

Van den Broek et al. (2010) established two terrain factors, established by an expert panel: land use and corridor. The terrain factor corridor addresses whether a corridor is followed, both on- and offshore. Thus, instead of using a preferential route, Van den Broek et al. (2010) manipulate the cost factors for deviating from the corridor, therefore overestimating the costs. The terrain factors for onshore and offshore are 1.0 and 0.9 respectively. Normally, offshore pipelines are more expensive than onshore pipelines. However, a factor of 0.9 is used here, due to the complex onshore situation of the Netherlands: peaty soil, densely populated and a large quantity of waterways and freeways (Knoope et al., 2013).

ZEP (2011)

ZEP (2011b) calculated the cost of CO_2 transport per tonne, with distances ranging between 180-1,500 km and two scenarios with annual capacities of 2.5 Mt/y and 20 Mt/y, see Table 7-2 and Table 7-3.

[25] Average conversion rate in 2011: $\$_{2011}$ 1.392 = €$_{2011}$ 1 (X-Rates, 2014)
[26] 150-200 inch = 3.8-5.1 meter
[27] To compare these numbers with IEA GHG (2013), $\$_{1990\text{-}1998}$ is converted into $\$_{2011}$ using the average conversion rate between 1990 and 1998 ($\$_{1990\text{-}1998}$ 1.41 = $\$_{2011}$ 1.00). Therefore, onshore pipelines are $\$_{2011}$ 47,732/in/mile and offshore pipelines are $\$_{2011}$ 81,299/in/mile.

Table 7-2: Cost of pipeline transport (€/tonne) for a capacity of 2.5 Mt/y (ZEP, 2011)

Distance (km)	Onshore	Offshore	Cost multiplier
180	5.4	9.3	1.7
500	n/a	20.4	n/a
750	n/a	28.7	n/a
1,500	n/a	51.7	n/a

The values for a capacity of 2.5 Mt/y are discarded (Table 7-3), because the costs for offshore can only be compared for 180 km, not for 500 and 750 km because this data is not available in ZEP (2011b).

Table 7-3: Cost of pipeline transport (€/tonne) for a capacity of 20 Mt/y (ZEP, 2011)

Distance (km)	Onshore	Offshore	Cost multiplier
180	1.5	3.4	2.26
500	3.7	6.0	1.62
750	5.3	8.2	1.54
1,500	n/a	16.3	n/a

For a distance of 180 km, onshore pipeline transport costs 1.5 €/tonne and offshore 3.4 €/tonne. In this case, offshore is 2.26 times more expensive than onshore. For a distance of 750 km, the offshore is 1.54 times more expensive (ZEP, 2011b). This factor is the cost multiplier. This is also shown in Table 7-3 and plotted for distances 180, 500 and 750 km in Figure 7-2. A trendline is added to the graph to show the relation.

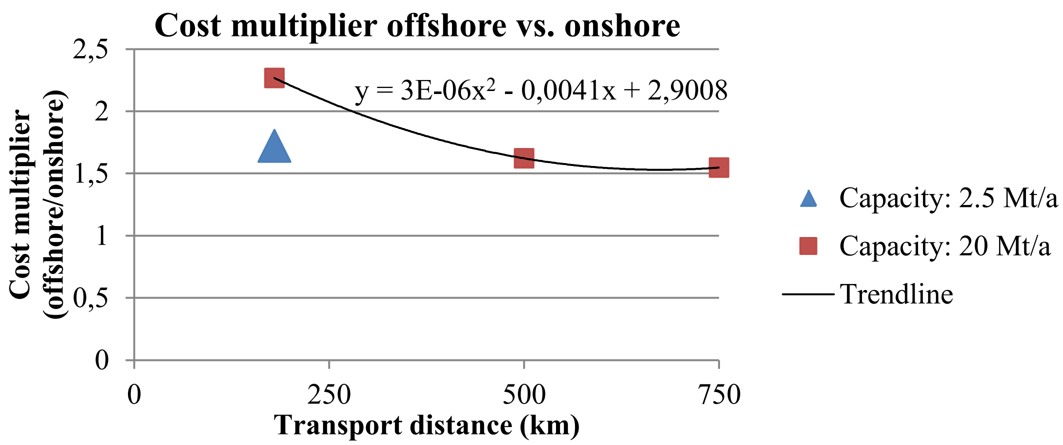

Figure 7-2: Cost multiplier offshore/onshore for a capacity of 2.5 Mt/y and 20 Mt/y (based on ZEP, 2011)

The cost multiplier varies over distance. However, a terrain factor is bound to the type of terrain and should be independent of pipeline length. Therefore, this thesis introduces a scaling factor. The relation between the distance in km (x) and the cost multiplier (y) is shown in Equation 1.

Equation 1

$$y = (3 * 10^{-6})x^2 - 0.0041\, x + 2.9008$$

7.2 Discussion of cost multipliers

A summary of the (ranges of) cost multipliers is shown in Figure 7-3. The multiplier ranges from 0.9 in Van den Broek et al. (2010) to 14 in IEA GHG (2013).

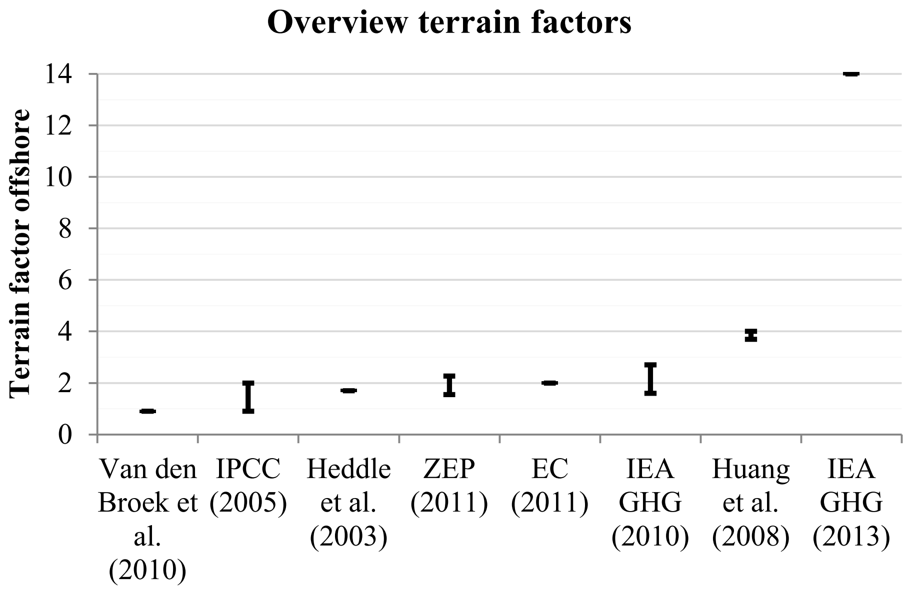

Figure 7-3: Overview terrain factors for offshore pipeline (base case onshore = 1)[28]

The value [0.9] from Van den Broek et al. (2010) is based on the arguments about the peaty soil and densely populated situation in the Netherlands. The value is therefore not used in this thesis. The high factor [14] of IEA GHG (2013) is discarded because offshore pipeline in the United States are very rare and cost levels are much higher than in a European context. Hence, this cost multiplier is not suited for this study, in which long distance offshore pipeline transport is required, and specific costs (e.g. per tonne or per km) are expected to be lower. The starting point of Huang et al. (2008) is that offshore pipelines are not aimed at large distances, i.e. the distances required to reach offshore depleted oil and gas fields. Therefore, Huang et al. (2008) tend to overestimate the costs for offshore transportation for longer distances.

The cost range in IPCC (2005) is relatively large, because a low and high estimate is given: 0.9 (cheaper) – 2.0 (more expensive). This number is useful, but not specific, because it contains data across the whole world (i.e. not specific for North Sea situation) and does not address water depths.
On the other hand, ZEP (2011) uses clear case studies with data from an industry panel. Because the input data is confidential, it is difficult to verify the results presented in the ZEP reports. However, the results are realistic because they comprise all facets of likely real-life cases for fully integrated CCS projects, including CO_2-EOR. Moreover, the cost multipliers are in line with Heddle et al. (2003) [1.7], European Commission (2011) [1.6-2.7] and IEA GHG (2010) [1.6-2.7].Therefore, this thesis uses the cost multipliers derived from ZEP (2011).

So far, cost multipliers are established based on depth and the pipeline trajectory. However, the offshore pipeline costs in the ZEP (2011) report are also dependent on depth, but they do not

[28] EC (2011) = European Commission (2011)

explicitly mention the cost structure. Therefore, the cost multipliers need to be decomposed into a depth component and a pipeline trajectory length component.

Moreover, water depth is a main factor for offshore pipeline trajectories (European Commission, 2011) and only implicitly included in ZEP (2011). The costs for laying the pipelines increase with depth. The range IEA GHG (2010) uses, depends on the depth. They differentiate between less and more than 500 m. However, this would result in an abrupt increase in costs when the pipeline trajectory goes from a depth of 499 m to 500m. Accordingly, a regression method is used to transform the terrain factor into a gradually increasing factor. The regression is used to intersect the terrain factors 1.6 at 250 m (average 0 and 500 m) and 2.7 at 750 m (average of 500 and 1000 m), see Figure 7-4.

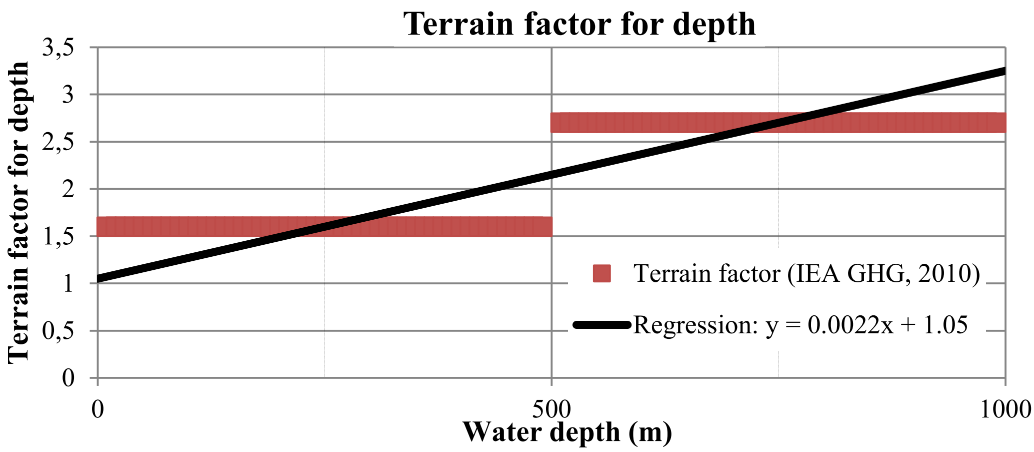

Figure 7-4: Derivation of terrain factor based on depth in IEA GHG (2010)

Equation 2 shows the formula for the terrain factor (TF_{depth}), which is dependent on depth (in m). Note that this equation only holds for a water depth up to 1000 m.

Equation 2

$$TF_{depth} = 0.0022 * \text{depth [m]} + 1.05$$

The offshore case studies in ZEP (2011) are based on a 180, 500 and 750 km pipeline from the Belgian coast in the direction of the Norwegian Continental Shelf (NCS). However, ZEP (2011) is not transparent to what extent depth influences costs. To get more information about the depth profile of the pipeline trajectory that is used as a case study in ZEP (2011), the depth profile is retrieved from the bathymetry of the North Sea (EMODnet, 2014). The depth is illustrated by the volatile black line in Figure 7-5.

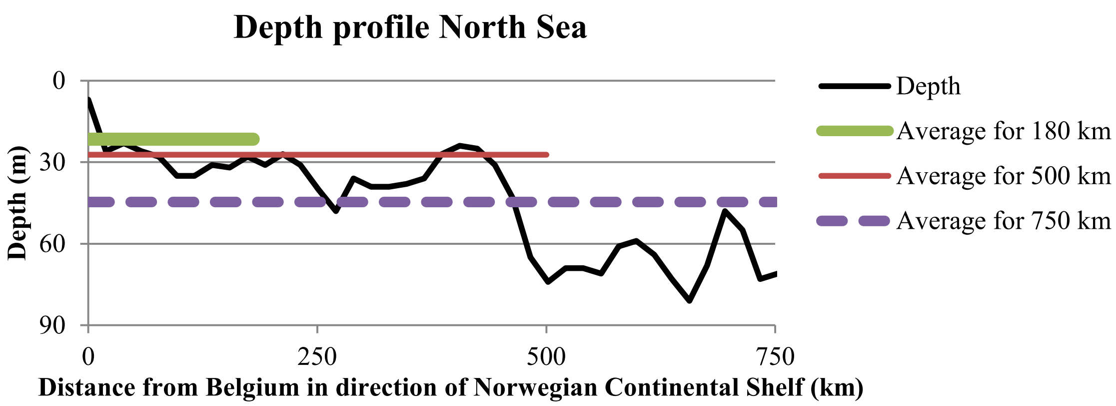

Figure 7-5: Depth profile North Sea from the Belgian coast to the Norwegian Continental Shelf, obtained from EMODnet (2014)

The average depths for the 180, 500 and 750 km trajectories are calculated to compare with the three corresponding cost multipliers for the offshore situation. The values for 180, 500 and 750 km are 21.5, 27.2 and 44.7 m respectively and are also indicated in Figure 7-5. These values can be used for the regression for the terrain factor dependent on depth (based on IEA GHG (2010)). The depth-induced cost multipliers are therefore: 1.10, 1.11 and 1.15. Consequently, the outcomes from ZEP are corrected for this depth, to establish the distance induced cost multiplier, i.e. the cost multiplier that is dependent on the length of the pipeline trajectory.

Table 7-4: Decomposing the ZEP (2011) cost multiplier

Distance	ZEP (2011) cost multiplier[29]	Depth-induced cost multiplier	Distance-induced multiplier
180 km	2.27	1.10	2.07
500 km	1.62	1.11	1.46
750 km	1.55	1.15	1.35

The distance-induced multipliers are plotted in Figure 7-6 and a trend line is added.

[29] The calculation of this cost multiplier is shown in Table 7-3

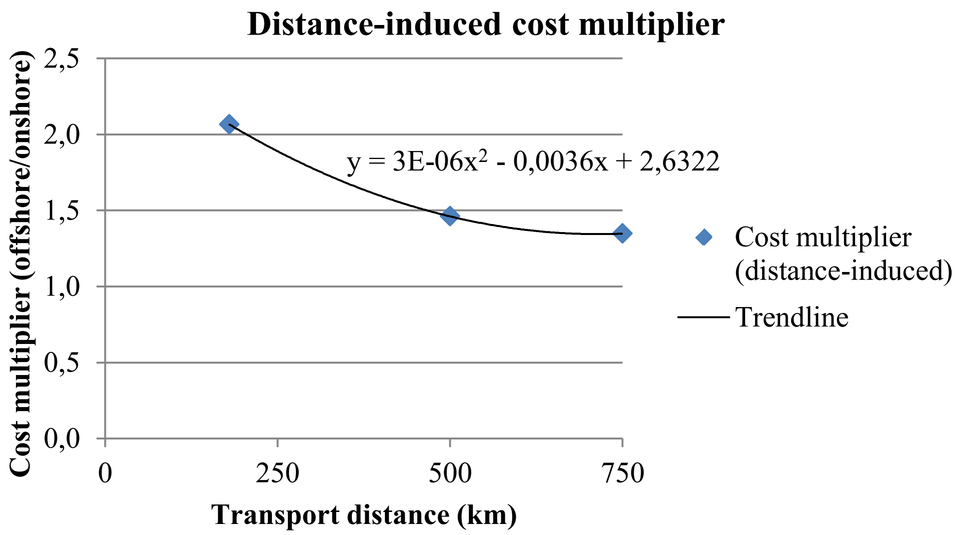

Figure 7-6: Cost multiplier (corrected for depth, thus distance-induced), based on case studies from ZEP (2011)

Equation 3 shows how the cost multiplier for length is calculated. This equation is obtained from the trendline fit of the three data points as derived from ZEP (2011) and IEA GHG (2010). Note that this equation only holds for distances from 200 to 750 km.

Equation 3

$$\text{Length multiplier} = (3 * 10^{-6}) * (\text{length of trajectory [km]})^{2} - 0.0036 * (\text{length of trajectory [km]}) + 2.6322$$

The costs calculations for offshore pipelines are calculate based on the onshore pipelines in PSS[30] and translated to offshore costs using the depth and the length of the offshore trajectory and other hindering objects in the trajectory, as shown in Equation 4.

Equation 4

$$\text{Offshore pipeline costs [€]} = \text{onshore pipeline costs in PSS [€]} * TF_{depth} * \text{length multiplier}$$

Therefore, TF_{depth} needs to be established. This is done by determining the value for TFdepth for every location on the map of the North Sea. The depth of the North Sea is analyzed based on EMODnet (2014). Figure 7-7 shows a heat map of the depth of the North Sea.

[30] The pressure is modeled using the advanced routing techniques as extensively described in Vandeginste & Piessens (2008). The offshore costs are then calculated using the terrain factors and cost multipliers.

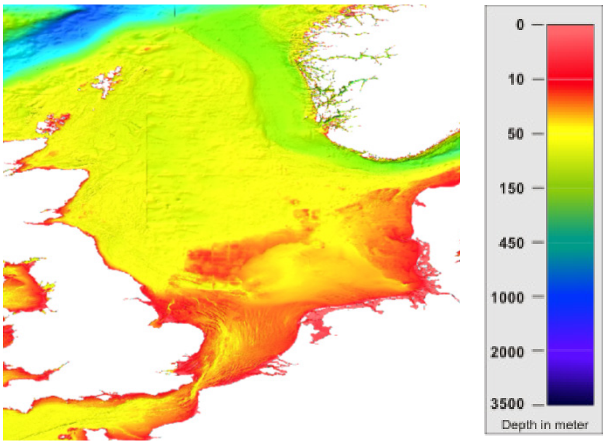

Figure 7-7: Bathimetry for North Sea region, from EMODnet (2014)

This data is used to establish a terrain factor for each 10x10 km cell, using Equation 2. Figure 7-8 shows how the data from Figure 7-7 is transformed to the terrain factors for the cells.

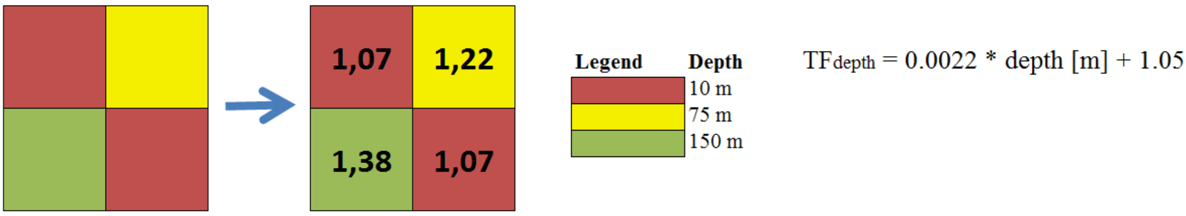

Figure 7-8: Simplified 2x2 cell grid "North Sea". Terrain factors are determined according to the depth (in this example 150, 300 and 450 meter). In the actual simulation, each 10x10 km cell has a value representing the average depth for that cell in the North Sea grid.

This results in a complete grid of the North Sea with a value for TF_{depth} in every cell.

7.3 Hinder factors

The routing of the pipelines should also consider hindering objects, such as existing pipeline infrastructure. These discrete elements can be described best using vector data.

DNV and TNO have investigated the opportunities for CCS in the Dutch sector of the North Sea for The Netherlands Oil and Gas Exploration and Production Association (NOGEPA). They have provided multiple numbers about pipeline crossings. The most common method for pipeline crossing is the use of concrete mattresses in combination with rock dump and special precaution for the cathodic protection. Figure 7-9 shows a subsea crossing of pipelines.

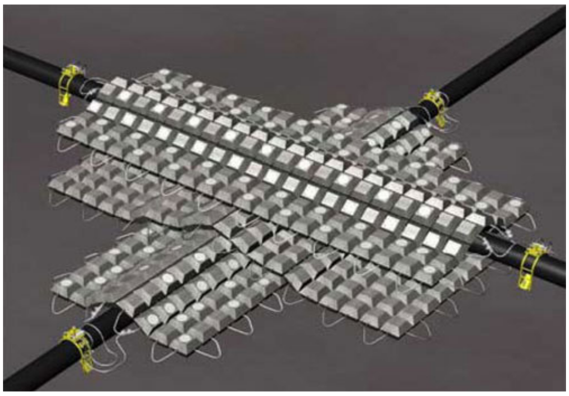

Figure 7-9: Subsea crossing of pipelines (NOGEPA, 2009)

The pipeline trajectory is determined by taking into account the terrain factors and the existing pipeline infrastructure that need to be crossed (or avoided). Pipeline infrastructure and land contours are mapped using vectors on a GIS-map of the North Sea. Several data sources (Harvard, 2014; Norwegian Petroleum Directorate, 2014; Petroleum Economist, 2006; Publieke Dienstverlening op de Kaart, 2014; TU Delft, 2014; Worldmap, 2014) are combined to create a realistic view of the North Sea when it comes to existing pipeline infrastructure, see Figure 7-10.

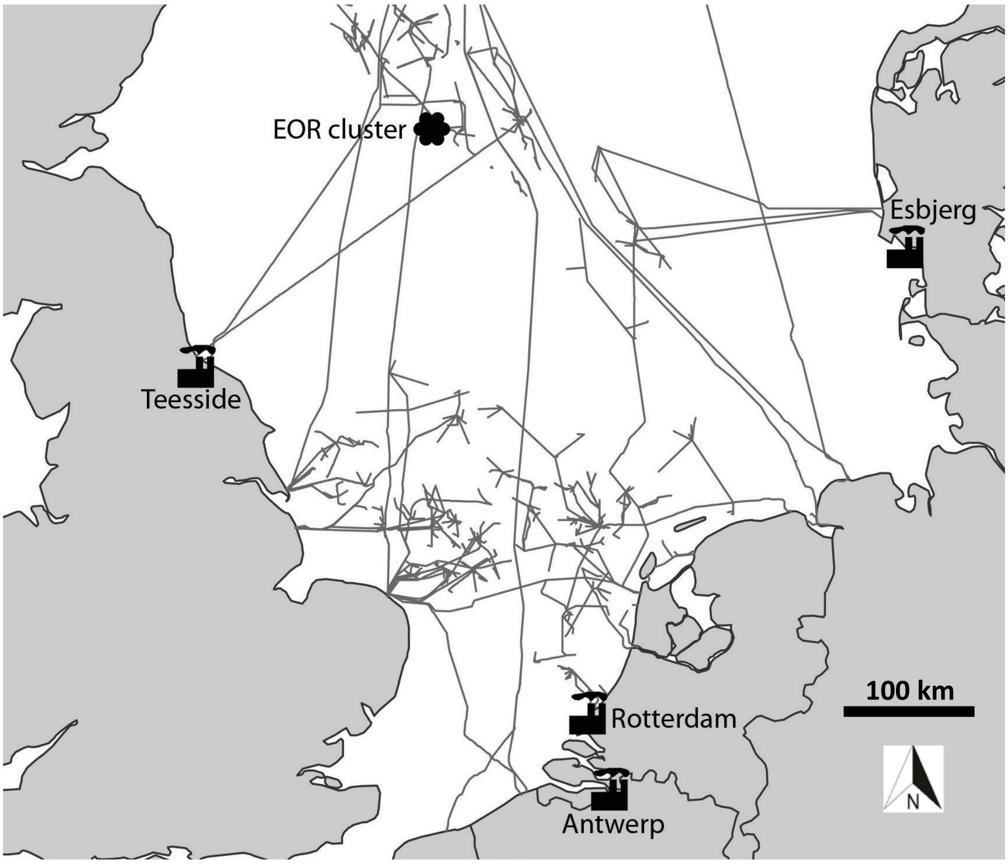

Figure 7-10: Location of the CO_2 sources (Teesside, Esbjerg, Rotterdam and Antwerp), the CO_2-EOR cluster and the existing *pipeline infrastructure in the North Sea*

When crossing a pipeline or crossing a beach (land fall), additional costs are applied. These are listed in Table 7-5.

Table 7-5: Additional expenses for different types of crossings (from CATO2 (2013); NOGEPA (2008, 2009))

Type of crossing	Additional expenses
Pipeline crossing[31]	€ 6 M
Landfall[32]	€ 11

The comprehensive data and simulations in PSS for onshore pipelines are combined with these offshore-specific data to calculate the optimal route. The route is the least-cost pathway from the CO_2 source (one of the four hubs) and optimized for both costs by going over the cells in the grid and crossing pipelines. Figure 7-11 shows an example of the routing optimization in two situations. In situation b, the least-cost route is to cross the existing pipeline twice, while in situation b, another route is taken.

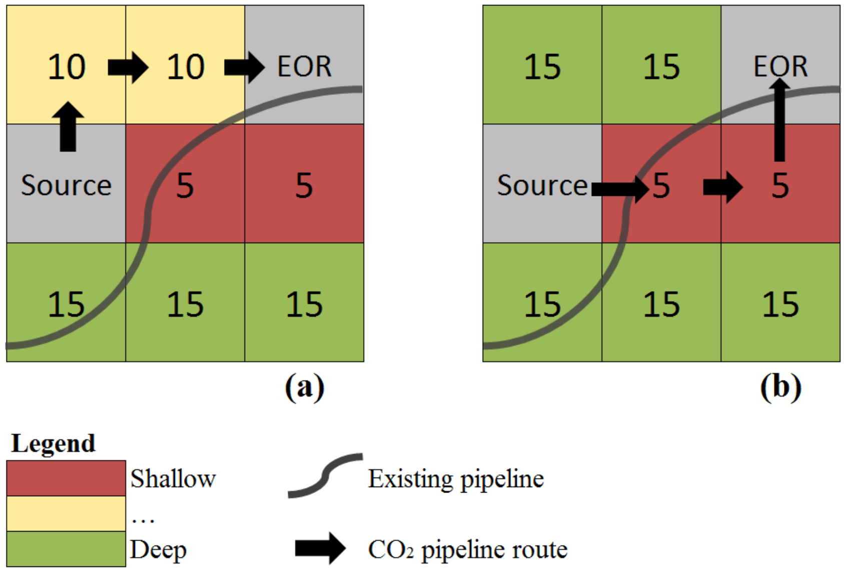

Figure 7-11: Example of a 3x3 cell grid. The numbers in the cell represent the costs for the pipeline. Two different situations are illustrated. Assume the costs for crossing an existing pipeline is 7.5. In situation a, the least-cost route is 10+10=20 (as compared to crossing the pipeline: 5+7.5+5+7.5=25). In situation b, crossing the pipeline is the least-cost route: 5+7.5+5+7.5=25 (as compared to 15+15=30). The grid, possible trajectories and calculations are strongly simplified to demonstrate the basic principle

At last, a cost multiplier is used to compensate for the relative decrease in offshore pipeline costs when the distance increases. Note that this is not a terrain factor, but dependent on the length of the trajectory. This multiplier is determined by calculating the length of the trajectory[33] and using Equation 3.

[31] Average from 36''x36'' pipeline crossing (€8 M) and 36''x8'' pipeline crossing (€4 M) because information about the pipeline diameter of the existing infrastructure is not available.
[32] Land fall is an onshore-offshore crossing
[33] The pipeline trajectory is optimized by PSS Router

7.4 Ship transport of CO_2

The ship transport value chain consists of liquefaction and gas conditioning, intermediate storage, loading, ship transport and unloading. The intermediate storage is required because the capture process of CO_2 is continuous while a ship is discrete. A loading facility is used to transfer the CO_2 from the intermediate storage to the ship. This is done with pumps adapted for high pressure and low temperature CO_2 service. The wall of the ship can transfer heat from the environment causing the CO_2 to boil and increasing the pressure in the tank. To counteract this, the CO_2 can be boiled-off, which is unfavorable because of climate and economic reasons. Therefore, a refrigeration unit to capture and liquefy the exhaust CO2 overcomes this (IPCC, 2005).

Figure 7-12: Ship transport chain from capture to injection

The costs for ship transport of CO_2 include investments for ships, loading and unloading facilities, intermediate storage and liquefaction units. There are operation costs and maintenance costs as well. The cost for ship transport is not known in detail because no large-scale system (>1 Mt CO_2/y) has been used yet. Costs can vary widely because economies of scale can have an enormous impact on the costs.

A recent report by CATO2 (2013a) analyzed the ship transport under the prevailing uncertain conditions. They acknowledge the flexibility of increased flexibility of delivery and the possibility to change loading a delivery sites. Ship transport is therefore modeled perfect foresight, using cost figures in €/tonne CO_2 for the complete ship transport chain, obtained from CATO2 (2013a).

The costs are based on annual capacity and distance. The transport costs depend on the annual capacity (in Mt/y). The numbers were calculated by CATO2 (2013a) with a discount rate of 10% for a transport distance of 500 km. These numbers show the transport costs for ships in which ship leasing contracts are assumed. This means that costs of ships transport are presented by operational expenses and not capital expneses. The capital expenses for the complete process of ship transport are investments for the liquefaction plant, loading and unloading facilities and intermediate storage (CATO2, 2013a).
A power trendline is added to the data points from CATO2 (2013a) to prepare the data for PSS, as shown in Figure 7-13.

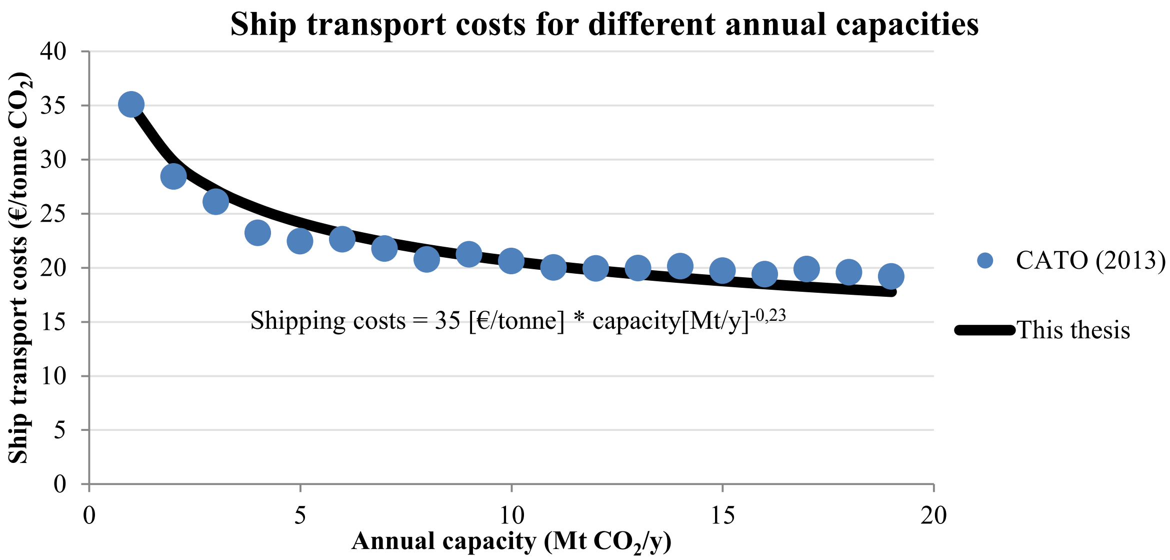

Figure 7-13: Ship transport costs for CO_2 for different annual capacities

CATO2 (2013a) calculated the costs for ship transport for distances of 50 to 1000 km for a scenario where the transported volume is 1 Mt/y during the first five years and 5 Mt/y in the remaining period of up to 25 years. These numbers cannot be used directly for costs depending on annual capacity, because the decrease in costs when the annual capacity increases would be neglected (as shown in Figure 7-13).

However, the costs for ship transport for distances of 50 to 1000 km can be used to determine the sensitivity of costs to distance. This is done by linear fitting the data points given in CATO2 (2013a), as is shown in Figure 7-14. Because 500 km is used as a fixed distance for calculating the ship costs depending on annual capacity, 500 km is used to normalize the dependency on distance (shown on the right axis in Figure 7-14).

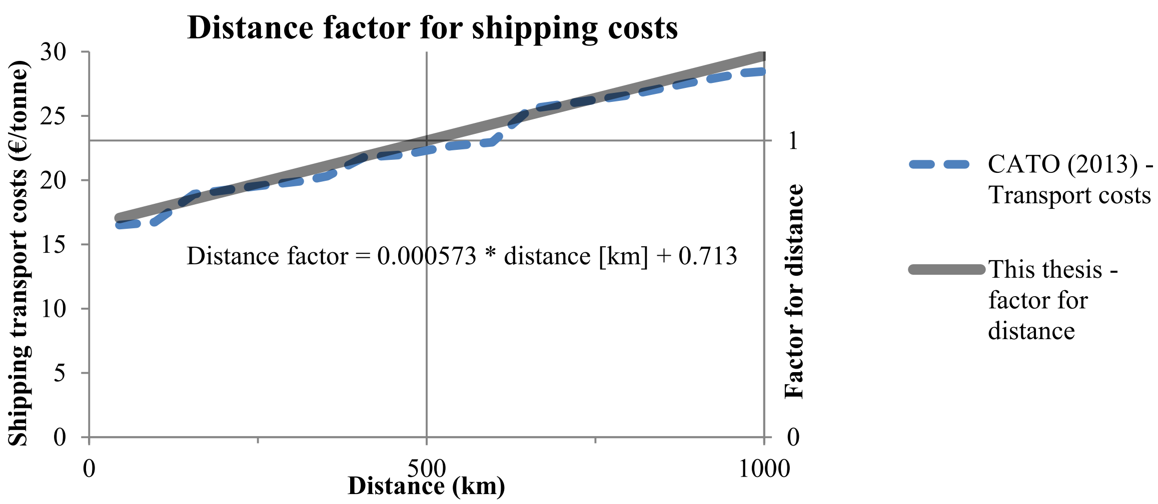

Figure 7-14: Distance factor for shipping costs. The blue dotted line indicates the transport costs in €/tonne for different distances. The scaling factor is a trendline and normalized for 500 km.

The equation for the trendline is shown in Equation 5.

Equation 5

$$\text{Distance factor} = 0.000573 * \text{distance [km]} + 0.713$$

In this thesis, the shipping costs are calculated based on the fitting curves in Figure 7-13 and Figure 7-14. Note that this equation only holds for annual capacities of more than 1 Mt/y and a distance of 50 to 1000 km. The boxed part of the equation is for the distance factor.

Equation 6

$$\text{Shipping costs} \left[\frac{€}{\text{tonne}}\right] = 35 \left[\frac{€}{\text{tonne}}\right] * \text{annual capacity} \left[\frac{\text{Mt}}{\text{y}}\right]^{-0.23} * \boxed{(0.000573 * \text{distance [km]} + 0.713)}$$

Although all the information is available to calculate the ship transport costs for CO_2, the current version of PSS does not have the required coding ready to use it for the simulations. Ship transport is therefore excluded from the simulations and only pipeline transport is taken into account.

8 Input for PSS: primary oil production and CO_2-EOR

This chapter gives an overview of the inputs for primary oil production and CO_2-EOR simulation in PSS.

8.1 Primary oil production

Extensive oil production data is published by UK Department of Energy & Climate Change (2014a) in which monthly production data is provided for all oil and gas fields in the UK sector of the North Sea. Production profiles from 10 offshore oil giants[34] in the North Sea oilfields are obtained and analyzed: Auk, Fulmar, Ross, Captain, Clair, Harding, Piper, Nelson, Alwyin North and Forties. The annual production figures are converted into a percentage of the maximum oil production of the fields. Furthermore, the moment when the oil production starts is defined as t=0. As can be seen in the density plot (Figure 8-1), the increase and decline of the annual production can be approximated by a lognormal curve.

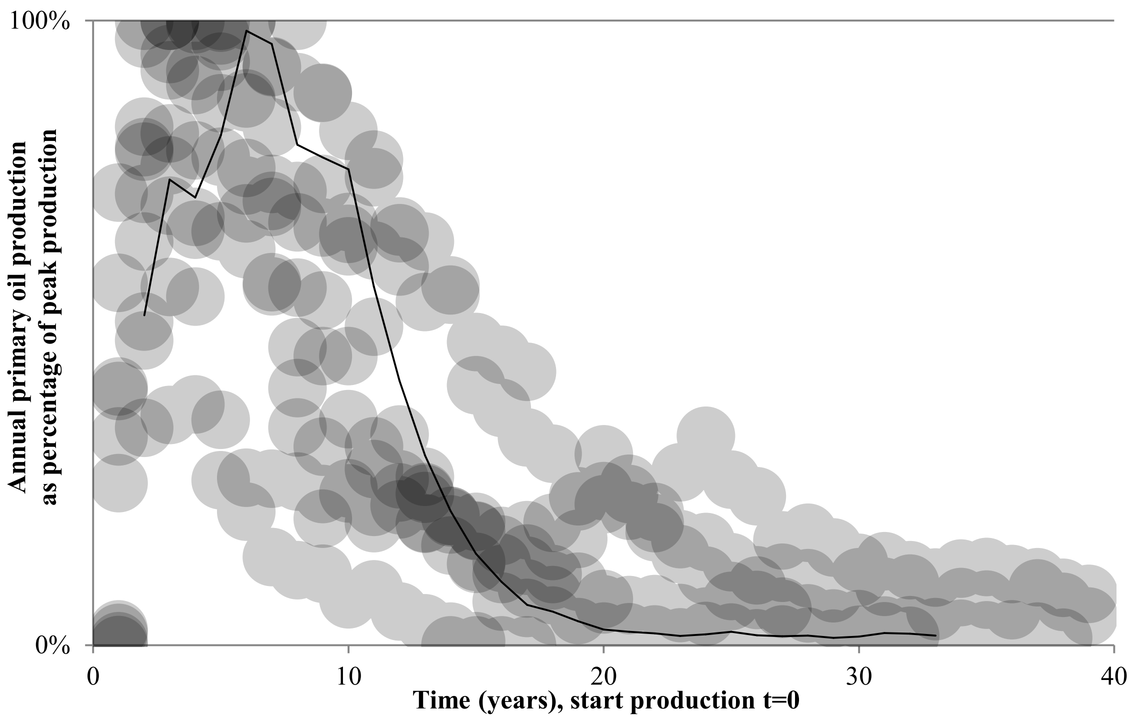

Figure 8-1: Oil production density plot of 10 North Sea oil giants in the UK sector. Production data from UK Department of Energy & Climate Change (2014). The black line represents a lognormal fit of the production data points.

Therefore, production profiles are modeled using lognormal curves in this thesis. These curves are appropriate because they give a good approximation of the actual production curve. A scale factor is used to augment the annual oil production, because by definition, the area under a lognormal function is equal to 1. The primary production curve is simulated using a lognormal curve and using the set of parameters (mean, standard deviation and scale factor), as shown in Equation 7.

[34] Primary recovery of more than 100 M bbl (1 Million barrels of oil is approximately 1,590,000 m^3)

Equation 7

$$\text{Primary production profile} = \text{lognormal distribution (mode, StD)} * \text{scale factor}$$

The scale factor represents the total (limit of the cumulative lognormal function) amount of oil recovered: $\text{Scale factor} = \text{OOIP (M bbl)} * \text{recovery factor (\%)}$. The recovery rate is expressed as percentage of the original oil in place (OOIP, the total hydrocarbon content of a reservoir, also referred to STOOIP[35] and STOIIP[36]). This thesis focuses on the value of timing of retrofitting from primary production to CO_2-EOR. Therefore, the declining section of the curve is of particular interest.

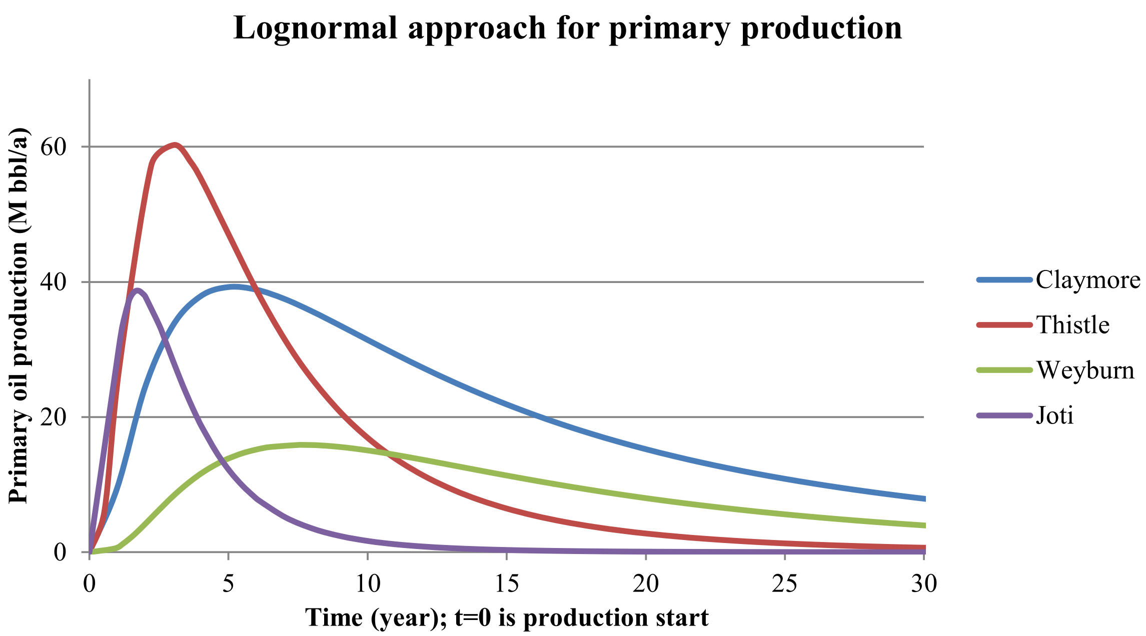

Figure 8-2: Lognormal approach for primary production. The aim of this figure is to illustrate the differences in production profiles of different fields. The lognormal curves are fitted to the actual monthly production figures from UK Department of Energy & Climate Change (2014a)

Sandrea & Sandrea (2007) calculated that the average recovery factor in the North Sea is 46%. Values of 60% or higher are very rare. To cover the variety of recovery factors of North Sea oil fields in this thesis, the recovery factor ranges from 35-60% of OOIP.

8.2 Changing production curves with the scale factor and mode

To account for the geological uncertainty of the reservoirs, this thesis uses stochastic variables for the oil production curves. The stochastic variables are the scale factor (this influences the height of the peak and the total oil recovered) and the mode. Figure 8-3 shows how synthetic production curves vary when changing the mode and scale factor. For instance, we can vary between quick peaky oil production curves and somewhat flatter curves, by changing the mode and standard deviation of the lognormal function. The standard deviation is kept constant, because changing this parameter would

[35] STOOIP = stock tank original oil in place
[36] STOIIP = stock tank oil initially in place

“change” the geological behavior of the reservoir: the area under the graph would also change when the standard deviation is tweaked.

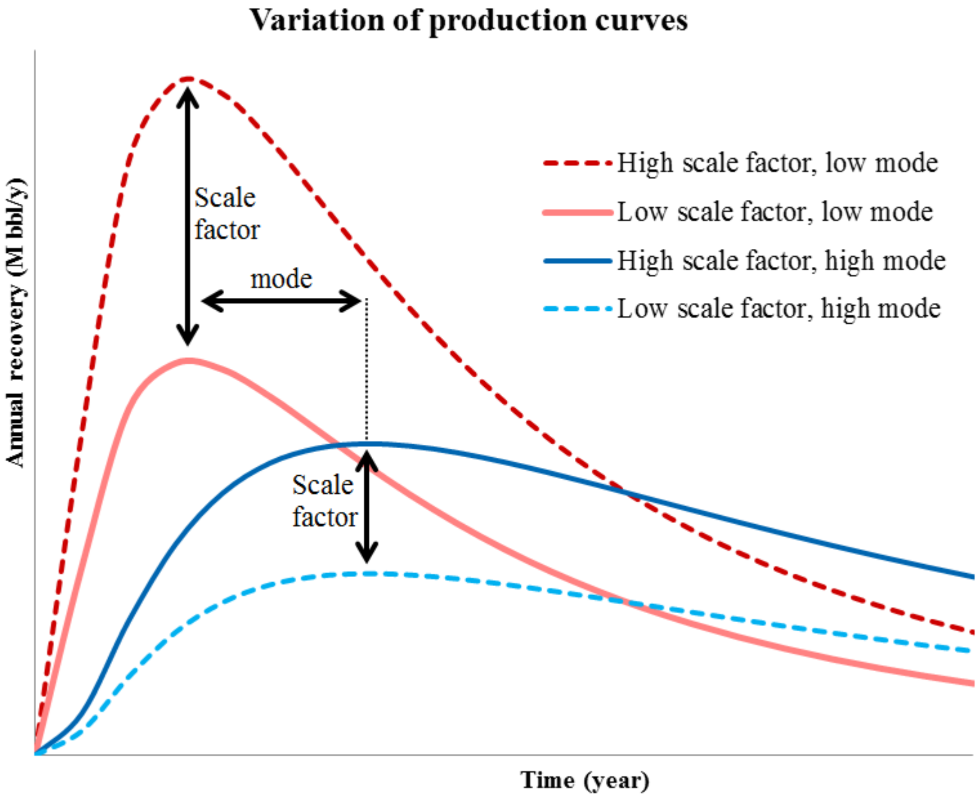

Figure 8-3: Example of the variation of production curves, when changing the scale factor and mode of the lognormal curve. The variations shown in the illustration represent the boundaries for the stochastic parameters: scale factor and mode. The scale factor represents the amount of oil (M bbl) that can be recovered. The mode represents the moment at which the oil production peaks.

Figure 8-4 shows the actual production data (solid light grey) for Forties, from 1974-2013 (UK Department of Energy & Climate Change, 2014a). The lognormal fit of this actual production profile is also shown (green-dotted). The arrows show how the curves are reshaped in horizontal (mode) and vertical direction (scale factor).

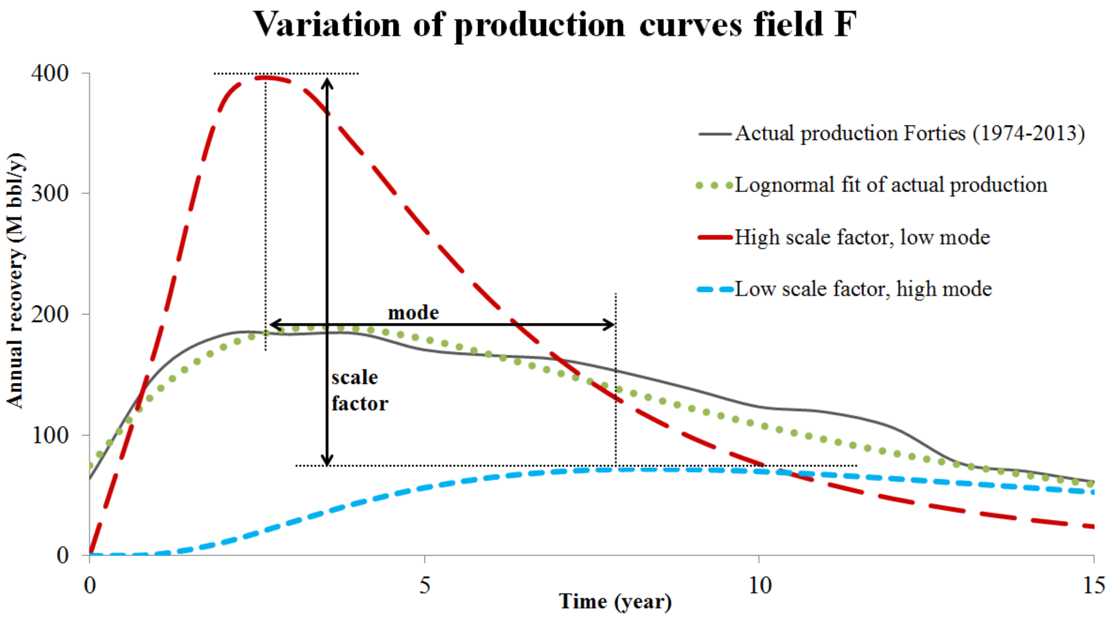

Figure 8-4: Variation of production curves for field F. The actual production data is shown (solid light grey) for the Forties field from 1974-2013 (UK Department of Energy & Climate Change, 2014a). The lognormal fit of this actual production profile is also shown (green-dotted). The arrows show how the curves are reshaped in horizontal (mode) and vertical direction (scale factor).

According to these ranges (the maximum and minimum scale factor and the maximum and minimum mode), Monte Carlo analysis will construct different production curves. Figure 8-5 shows 60 of these Monte Carlo loops for the Forties field.

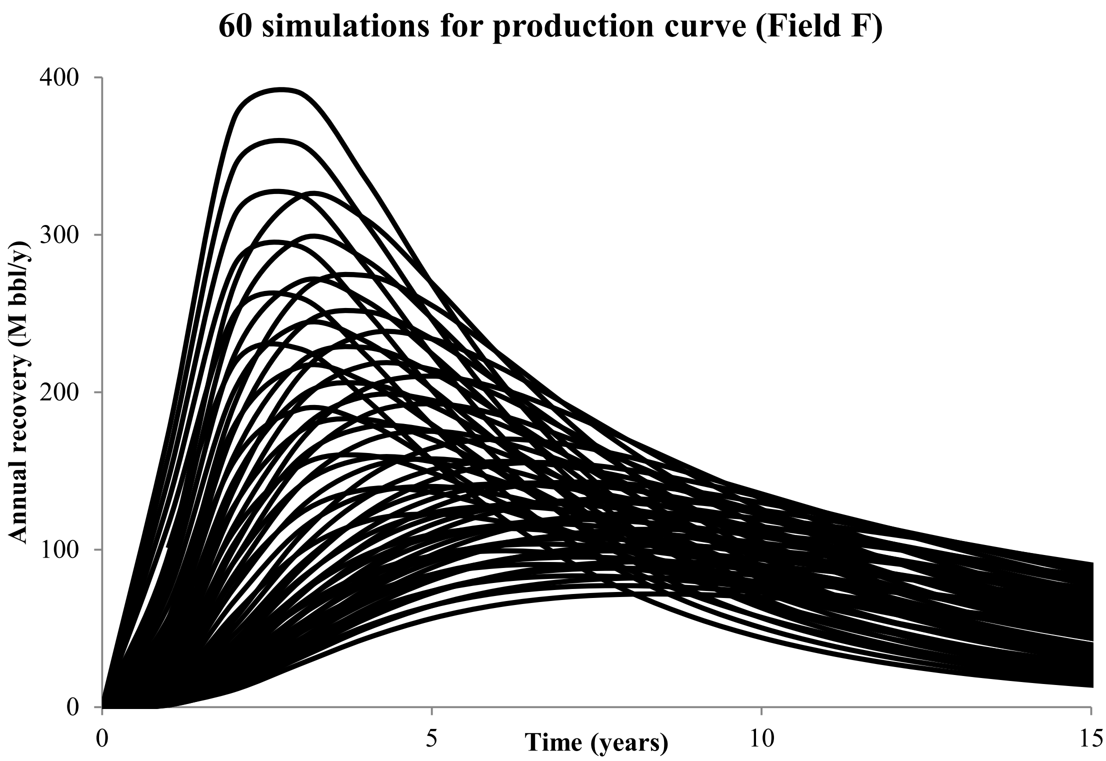

Figure 8-5: Monte Carlo simulations for the production curve of field F. The recovery factors ranges from 35-60% (OOIP=4200 M bbl, therefore the scale factor ranges from 1470-2520 M bbl), the mode ranges from 4.49-14.49 and the standard deviation is 0.74.

8.3 Enhanced oil recovery

8.3.1 Production profile for CO_2-EOR

Element Energy (2012) has mapped the potential for CO_2-EOR in the UK sector of the North Sea. They conducted a case study for a large oil field 161 km north-east of Aberdeen. The first oil was produced in late 1977. Based on the Claymore oil field, two scenarios for CO_2 injection for CO_2-EOR have been designed by Element Energy (2012) and Scottish Centre for Carbon Storage (2009). One scenario is aimed at sequestrating CO_2 and therefore assumes a constant influx of CO_2. Another scenario is aimed at minimizing the demand for fresh CO_2; the recycling of CO_2 is optimized. The data from the two scenarios are digitized and shown in Figure 8-6 and Figure 8-7.

The base oil production is the primary oil production that continues although CO_2 is being injected for enhanced oil recovery. There is some oil that is produced anyway (also without CO_2 injection), therefore this is called base oil production. It is difficult to appoint a barrel of oil to a certain production technique (i.e. primary or enhanced). Hence, base oil production is assumed to decrease over time following the extrapolated decline curve of the primary production.

The EOR production is the net additional production of oil due to CO_2 injection. Fresh CO_2 is the CO_2 that is delivered to the EOR project, either by pipeline or by ship. The individual need for fresh CO_2 declines over time, because the CO_2 is co-produced with the oil and recycled: the CO_2 is separated from the oil and dried, compressed and re-injected into the field (Element Energy, 2012).

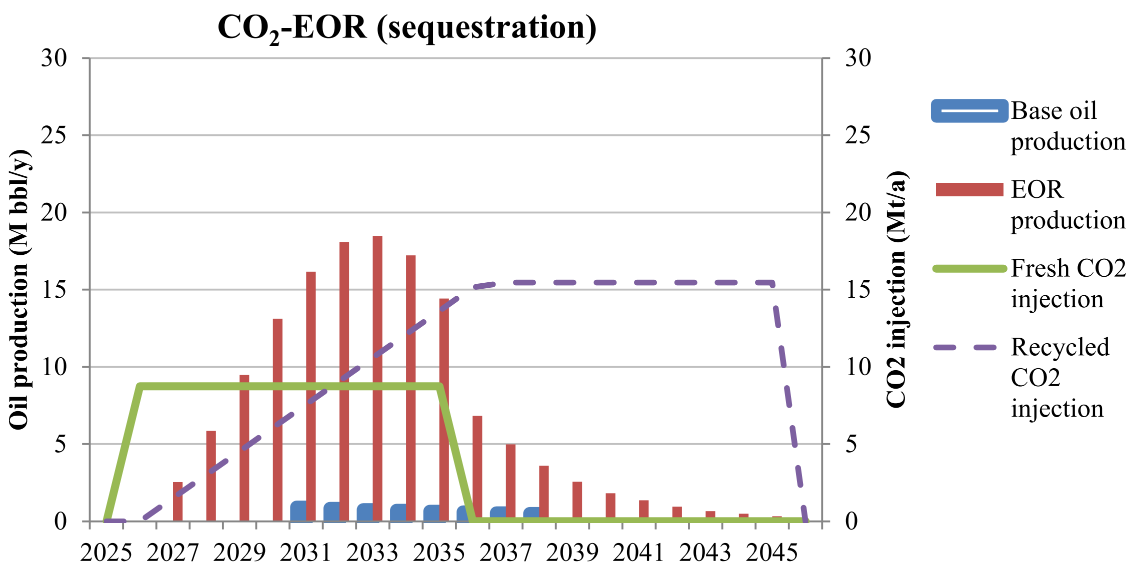

Figure 8-6: Profiles for oil production and CO_2 injection for CO_2-EOR based on characteristics of Claymore. Optimized for CO_2 sequestration (demand for fresh CO_2 constant) Data points from Element Energy (2012).

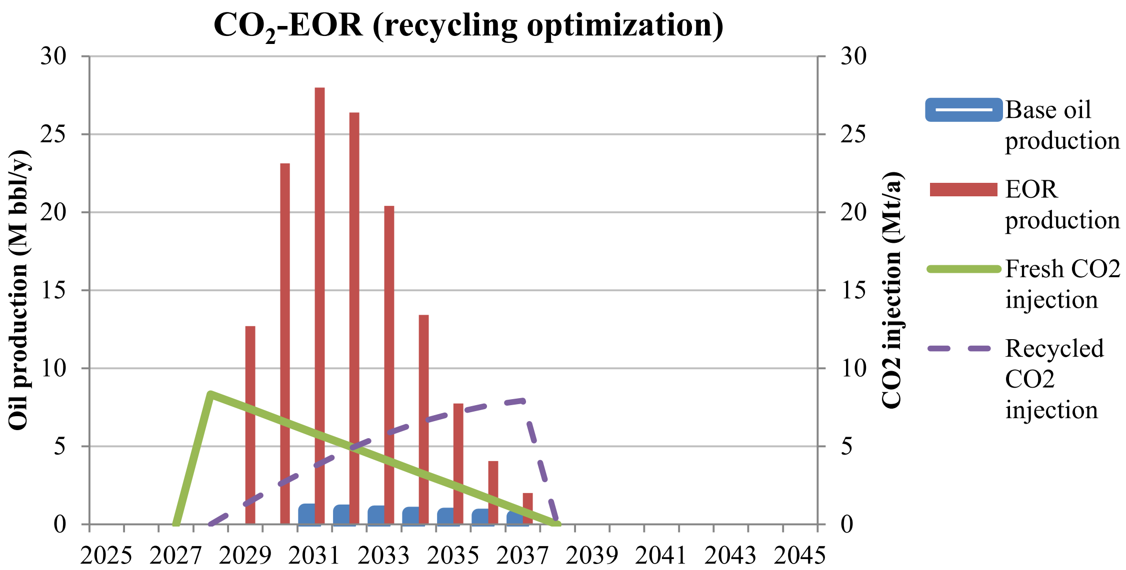

Figure 8-7: Profiles for oil production and CO_2 injection for CO_2-EOR based on characteristics of Claymore. Optimized for CO_2 recycling (lowering demand for fresh CO_2). Data points from Element Energy (2012).

Total oil recovered is approximately 140 M bbl in both scenarios, although the lifetime of the CO_2-EOR project is shorter in the CO_2 recycling scenario (Scottish Centre for Carbon Storage, 2009),. Therefore, the peak annual production is higher in the CO_2 recycling scenario (28 M bbl/y versus 18 M bbl/y).

The two scenarios provide a useful starting point for this study. However, some pitfalls need to be addressed. The total CO_2 injected is minimized in the recycling optimization scenario, compared to the sequestration scenario. The total amount of CO_2 injected is kept constant between 8 and 10 Mt/y in the sequestration scenario, while the demand for fresh CO_2 is decreasing over time. The recycling optimization scenario could be more suitable for this thesis when the focus is on oil production, rather than the combination with CO_2 sequestration (from anthropogenic sources) (Element Energy, 2012). However, the sequestration scenario is not appropriate for this study, because CO_2 injection continues although the incremental oil recovery clearly approaches zero. In addition, the goal of this thesis is to assess EOR, not storage of CO_2. The peak in the CO_2 supply (fresh CO_2) in the recycling optimization scenario is unrealistic because scaling the infrastructure to such a peak is not economically viable in an offshore setting. The cost of such infrastructure is relatively high, hence it is favorable to make use of the full capacity of the infrastructure over the lifetime of the project(s). In practice this corresponds to a constant supply of CO_2, as is the starting assumption of the sequestration scenario. Furthermore, the base oil production (oil that would also have been produced without CO_2 injection) is only visible after a few years of injecting, while in a real case, there would be a declining base oil production from 2025 onwards. This is not shown in the figure. Therefore, realistic aspects of the two scenarios are used to form the basis for the scenarios used for this study: we use a constant supply of fresh CO_2 and we stop injecting CO_2 when the economic limit is reached (i.e. the oil revenues do not outweigh the cost of CO_2 supply).

Similar to the primary recovery, the production curve for enhanced oil recovery is also simulated with a lognormal curve, as expressed in Equation 8.

Equation 8

$$\text{Production profile } CO_2EOR = \text{lognormal distribution (mode, StD)} * \text{scale factor}$$

8.3.2 Recovery rate

The recovery rate indicates the total potential of oil recovery when using CO_2-EOR, expressed as a percentage of OOIP. Because it is expressed as a percentage of OOIP, it is independent from the oil that is recovered during primary production. The European Commission (2005) uses a low estimate of 4-9% of OOIP for miscible CO_2 and lowers this number to 3-7% for the North Sea region based on reservoir modeling. The number is lowered because of relatively high primary and secondary recovery (44-55% of OOIP) of the offshore fields. Huang et al. (2013) use an estimate from the US Department of Energy ranging from 10-15% of OOIP. Andrei et al. (2010) state 4-12% of OOIP, but later on also mention 5-15% of OOIP. IEA GHG (2009) determines a recovery rate of 18% of OOIP, based on 14 sandstone fields in the UK sector of the North Sea graben. US Department of Energy (2008) based the recovery rate on one case study with data from 1992: 10-20% of OOIP. Lake & Walsh (2008) use CO_2 solvent flooding results in the US, with an ultimate recovery factor of 12% of OOIP. Lee & Kam (2013) estimated a recovery rate of 6.0% for one case study in Midway Sunset Field, California. These numbers are graphically represented in Figure 8-8.

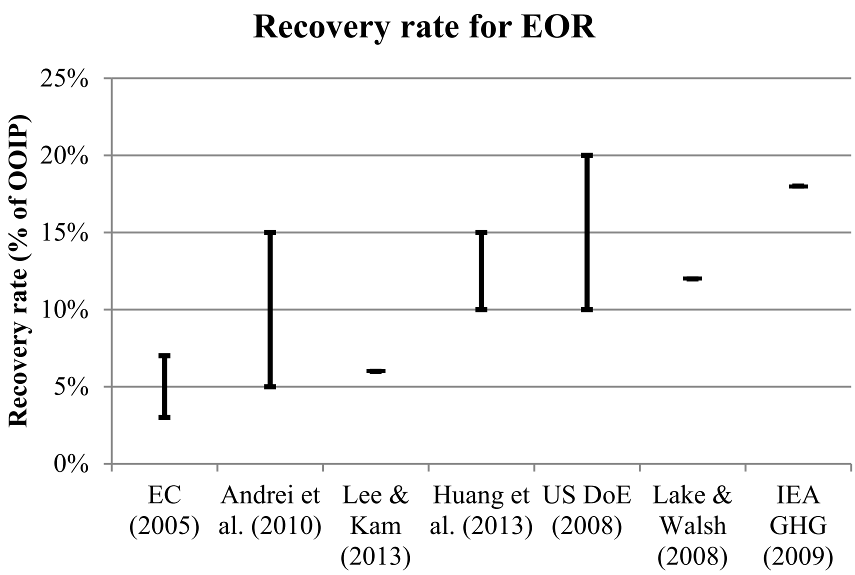

Figure 8-8: Overview values in literature for recovery rate (% of OOIP) of EOR. EC (2005) refers to European Commission (2005).

The differences can be explained because different basins (Europe vs. US) are used and because of specific characteristics of different oil reservoirs. Moreover, the two situations differ in operation, geological characteristics and maturity of the oil field. The values from the European Commission (2005) provide a useful starting point because they are based on reservoir simulations for potential North Sea CO_2-EOR projects. The range refers to high and low estimates, based on reservoir simulations and US experience. Therefore, in this study the recovery rate for EOR ranges from 3 to 7% of OOIP. This range is used for the stochastic parameter in PSS. For instance, the EOR recovery rate varies between 60 and 140 M bbl for a field with 2,000 M bbl OOIP.

8.3.3 CO_2-EOR ratio

The EOR ratio is a number which represents the incremental oil recovery from injection of CO_2 and is expressed as the number of barrels of oil per tonne of CO_2 injected. The European Commission (2005) uses a typical number of 3.0 bbl/tCO_2 (0.33 tCO_2/bbl) for efficient CO_2-EOR projects. Kemp & Sola Kasim (2012) use a stochastic variable for the UK sector of the North Sea with a minimum, maximum and most likely value of 1.6, 2.6 and 1.8 bbl/tCO_2. Andrei et al. (2010) use a ratio of 3.3 bbl/tCO_2 for EOR projects with miscible CO_2. Lake & Walsh (2008) use CO_2 solvent flooding results in the US, with a utilization factor of 10 MCF/bbl, which translates[37] to 1.9 bbl/tCO_2 . US Department of Energy (2008) states that in general 3.1-3.8 bbl/tCO_2 are used. IEA GHG (2009) analyzed 50 CO_2-EOR projects (11 of them in the US, 2 in Europe) with ratios from 2.8-4.2 bbl/tCO_2. These numbers are graphically represented in Figure 8-9.

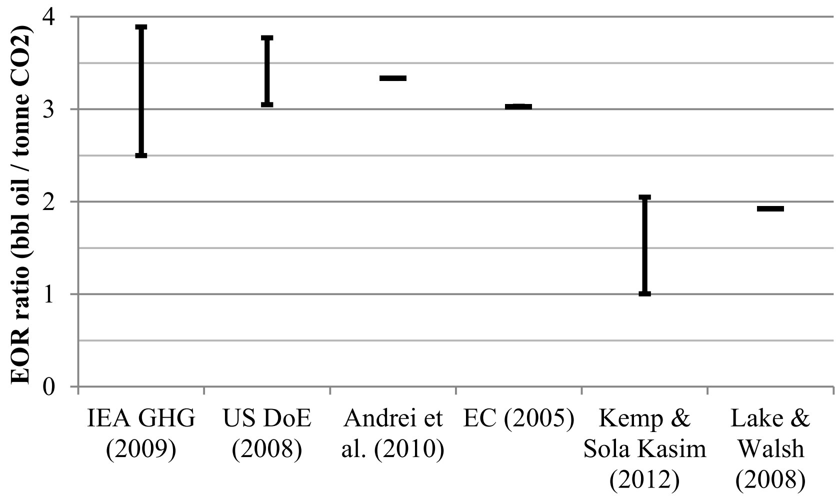

Figure 8-9: Overview values in literature for EOR ratio (in bbl oil/tonne CO_2 injected)

[37] The volumetric number (MCF = 1,000 cubic feet) is translated to mass (tonnes) using the conversion factors by US Department of Energy (2010): 19.25 MCF = 1 tonne of CO_2.

The previous numbers show the total amount of oil recovered during EOR divided by the total amount of CO_2 injected. However, the EOR ratio itself develops over time, following the EOR ratio profile. The EOR ratio builds up quite firmly to a peak and further in time declines relatively gently, as shown in Figure 8-10 (Element Energy, 2012).

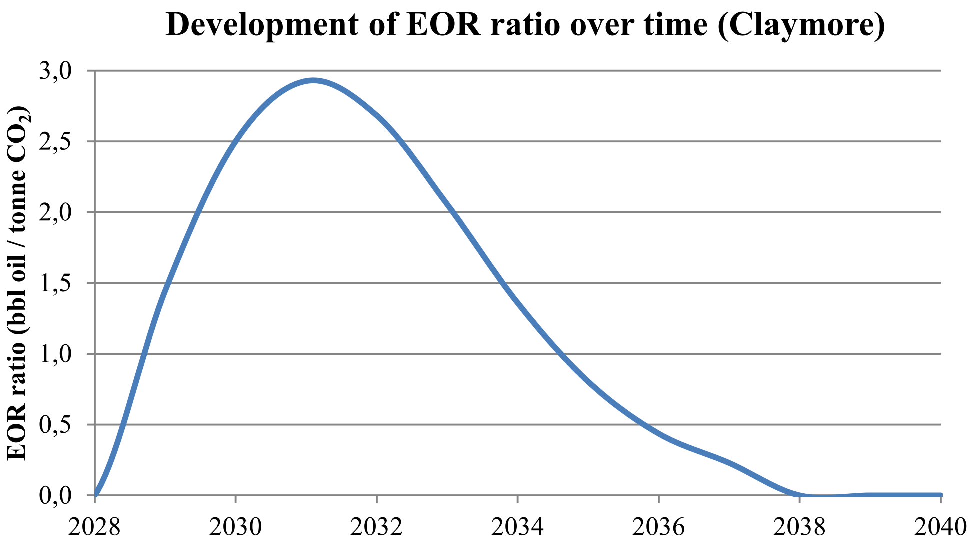

Figure 8-10: Development of EOR ratio over time for the Claymore oil field. The EOR ratio is expressed as the annual number of bbl of oil recovered divided by the annual number of tonnes of CO_2 injected. EOR values calculated from oil recovery and injected CO_2 in a recycling optimization profile from Element Energy (2012). The average EOR ratio in this example is 1.5.

8.4 Interaction primary oil production and CO_2-EOR

Parameters are included that are often neglected in CO_2-EOR simulations such as the amount of primary oil that is recovered because the project lifetime is extended because of CO_2-EOR.
To show the interaction between primary oil production and CO_2-EOR, Figure 8-11 illustrates the production curves. When CO_2-EOR is initiated, the project end is delayed. During CO_2-EOR, the oil production is increased (green area) and the primary oil production is extended (red). The orange area indicates the oil that would have been produced during primary production, which is now produced by CO_2-EOR.

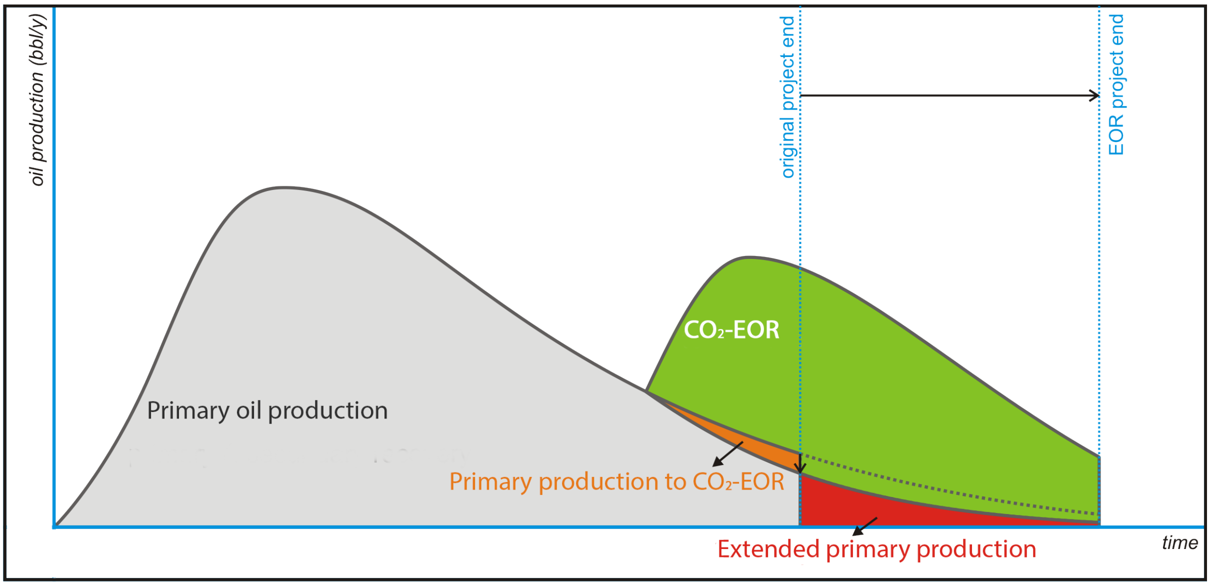

Figure 8-11: Schematic overview of production profiles for primary and enhanced oil recovery

8.5 Cases for CO_2-EOR

The oil fields Claymore, Fulmar en Forties (all located in the UK sector of the North Sea) are used to construct seven projects for the simulation. These seven generic projects are constructed as a cluster in a hexagonal lay-out. The techno-economic parameters that are needed to construct the projects are for primary production (OOIP, production profile etc.) and the CO_2-EOR potential (incremental barrels recovered, annual injection etc.).

8.5.1 Claymore

OOIP is 1455 M bbl (European Commission, 2005). Primary recovery has produced 810 M bbl from 1974-2013 (UK Department of Energy & Climate Change, 2014a). The potential for CO_2-EOR is estimated to be an additional 131 M bbl (European Commission, 2005). The minimum required annual amount of CO_2 to be injected is 2.2 Mt/y, the maximum 4.1 Mt/y (European Commission, 2005).

8.5.2 Fulmar

OOIP is 825 M bbl (European Commission, 2005). Primary production data is obtained from (UK Department of Energy & Climate Change, 2014a). The potential for CO_2-EOR ranges from 33.0-74.3 M bbl (European Commission, 2005), 82 M bbl (Element Energy, 2012) to 153 M bbl (IEA GHG, 2009). The annual CO_2 requirement is 1.3 Mt/y (European Commission, 2005). The maximum injection rate for permanent storage is 4.3 Mt/y (Kemp & Sola Kasim, 2012). The EOR ratio is 3.91 bbl oil/tonne CO_2 (IEA GHG, 2009).

8.5.3 Forties

OOIP is 4,200 M bbl (European Commission, 2005). Primary production data is obtained from UK Department of Energy & Climate Change (2014a). The potential for CO_2-EOR ranges from 168-378 M bbl (European Commission, 2005) to 420 M bbl +-50% (Element Energy, 2012). The investment costs for CO_2-EOR range from a total of 1073 M€ (European Commission, 2005) to 50M GBP per platform (Element Energy, 2012).

8.5.4 Generic cases: seven oil fields

Field A is based on Claymore and consists out of 30 production and 19 injection wells (Talisman Energy, 2006b). Field B is 1/3 of the size of A. Field C is 2/3 of the size of A. Field B therefore has 10 production and 7 injection wells and Field C consists of 20 production and 13 injection wells.
Field D is based on Fulmar and consists out of 22 production and 11 injection wells (Talisman Energy, 2011). Field E is half the size of D. Field E therefore has 11 production and 6 injection wells.
Field F is based on Forties and consists out of 81 production and 22 injection wells (Offshore Technology, 2014). Field G is half the size of F. Field G therefore has 41 production and 11 injection wells. The fields are named according to Table 8-1.

Table 8-1: Field names A-G

Field names
A (Claymore)
B (Claymore 33%)
C (Claymore 67%)
D (Fulmar)
E (Fulmar 50%)
F (Forties)
G (Forties 50%)

8.6 Input parameters

This section gives an overview of the parameters that are used for the simulation of CO_2-EOR. For primary production the input parameters are listed in Table 8-2. For EOR the input parameters are listed in

Table 8-3.

Table 8-2: Input parameters for primary production

Input parameter	Unit	Remarks
OilProdOOIP	Million barrels [M bbl]	Oil originally in place. Physical amount of oil available in the reservoir
OilProdRecovery	Fraction [-]	Recovery rate. Fraction of oil that is recovered during primary and secondary oil production.
OilProdMean	-	Mean of lognormal curve for primary oil production. Calculated from the mode.
OilProdStD	-	Standard deviation for lognormal curve of primary oil production.
OilProdMin	M€	Boundary condition for simulation purposes. Minimum required annual revenues from oil during primary production.

Table 8-3: Input parameters for enhanced oil recovery

Input parameter	Unit	Remarks
EOROOIP	Million barrels [M bbl]	Identical to OilProdOOIP
EORRecovery	Fraction	Recovery rate. Fraction of oil that is recovered during EOR.
EORMean	-	Mean of lognormal curve for EOR.
EORStD	-	Standard deviation for lognormal curve for EOR.
EORDelay	Years [y]	Delay in oil production when EOR is started, i.e. time before first EOR oil is produced
OPtoEORFactor	Million barrels [M bbl]	Oil production that also would have occurred when EOR would not be applied.
EORCO2RecycRate	Fraction [-]	Recycling rate of CO_2, expressed as a fraction of CO_2 injected.
EORCO2RecYMax	Years [y]	Time at which CO2RecRate reaches the maximum value, because the recycling of CO_2 builds up over time.
EORCO2RecycDelay	Years [y]	Delay in CO_2 recycling, i.e. time before first CO_2 is produced.
EORCO2Req	Million tonnes per year [Mt/y]	Maximum amount of CO_2 required for injection.

8.6.1 Values of input parameters

The average recovery rate for primary production (OilProdRecovery) is between 35 and 60%, for North Sea oil fields according to Sandrea & Sandrea (2007). For field D and E, this is 35-69%, because of the exceptional high recovery rate of Fulmar (69.3%). The mean (OilProdMean) and standard deviation (OilProdStD) are determined by fitting a lognormal curve and minimizing the squared errors for the declining phase of the curve.

An overview of the values for the input parameters for primary production of all the fields is shown in Table 8-4.

Table 8-4: Overview of input parameters of primary production of field A, B, C, D, E, F and G

	A	B	C	D	E	F	G
OilProdOOIP[38]	1455	485	970	825	413	4200	2100
OilProdMean[39]	2.15-2.61	2.15-2.61	2.15-2.61	1.16-2.22	1.16-2.22	1.50-2.67	1.50-2.67
OilProdStD	0.98	0.98	0.98	0.47	0.47	0.74	0.74
OilProdRecovery	0.35-0.60	0.35-0.60	0.35-0.60	0.35-0.69	0.35-0.69	0.35-0.60	0.35-0.60
OilProdMin[40]	165 M€	55 M€	110 M€	94 M€	47 M€	476 M€	238 M€

The EOROOIP is identical to OilProdOOIP, because it is the physical amount of oil initially in place. The recovery rate for EOR (EORRecovery) is between 3 and 10% for A, B, C, D and E which is in line with Element Energy (2012) [10%] and European Commission (2005) [3-7%]. For fields F and G, the rate is between 3 and 9%, which is in line with European Commission (2005). The mean (EORMean) and standard deviation for EOR (EORStD) are obtained from fitting a lognormal curve for the production profiles adapted from Element Energy (2012). The delay in oil production for EOR (EORDelay) is 18 months (Jakobsen, Hauge, Holm, & Kristiansen, 2005; Advanced Resources International (2011). The recycling rate of CO_2 (EORCO2RecycRate) is 75% (Klokk et al., 2010). The time it takes for the injected CO_2 to breakthrough (EORCO2RecycDelay) is 2 years and the time it takes for the recycling rate to reach its maximum (EORCO2RecYMax) is 5 years (European Commission, 2005). EORCO2Req is the amount of CO_2 injected in Mt/y. An overview of the values for the input parameters for the potential CO_2-EOR projects is shown in Table 8-5.

Table 8-5: Overview of input parameters for the potential CO2-EOR projects A, B, C, D, E, F and G

	A	B	C	D	E	F	G
EOROOIP[38]	1455	485	970	825	413	4200	2100
EORRecovery	0.03-0.10	0.03-0.10	0.03-0.10	0.03-0.10	0.03-0.10	0.03-0.09	0.03-0.09
EORMean[41]	1.59-2.07	1.59-2.07	1.59-2.07	1.59-2.07	1.59-2.07	1.59-2.07	1.59-2.07
EORStD	0.40	0.40	0.40	0.40	0.40	0.40	0.40
EORDelay[42]	1.5	1.5	1.5	1.5	1.5	1.5	1.5
EORCO2RecycRate	0.75	0.75	0.75	0.75	0.75	0.75	0.75
EORCO2RecycDelay[42]	2	2	2	2	2	2	2
EORCO2RecYMax[42]	5	5	5	5	5	5	5
EORCO2Req[43]	4.1	1.37	2.73	1.3	1	13.7	6.9

[38] In million barrels of oil [M bbl]
[39] Mode ranges from -5 to +5 years
[40] All based on Claymore "A" (see section 5.4). The production minimum (M bbl oil per year) is determined by dividing this number with the oil market price in the relevant year.
[41] Mode ranges from -3 to +3 years
[42] Time in years
[43] In million tonnes of CO_2 per year [Mt/y]

8.7 Cost structure for CO_2-EOR

The costs for CO_2-EOR can be categorized into capital expenses and fixed and variable operational expenses.

8.7.1 Capital expenses for retrofitting oil platforms to CO_2-EOR

When primary or secondary oil recovery is exhausted, EOR can be applied. This study assumes that the oil platforms are retrofitted to make them suitable for CO_2-EOR. Therefore, information is needed about the additional investments for retrofitting. This is referred to as the capital expenses for CO_2-EOR.

The capital expenses are calculated based on cost figures from two references. NOGEPA (2009) estimate the capital expenses of 7-16 M€[44] for a platform when retrofitting from primary production to CO_2 injection for underground storage, depending on whether it is a main or satellite platform. However, there needs to be compensated for the fact that additional equipment is required for EOR operations. Therefore, the capital expenses are estimated[45] using the number of production and injection wells and the requirements for the recycling of CO_2. The injection wells require an investment of €23.2M and production wells a smaller investment of €9.28M (£20M[46] and £8M respectively, from Element Energy (2012)). Recycling CO_2 requires an investment of £20M per Mt CO_2 that is recycled annually (Element Energy, 2012). Equation 9 shows how the capital expenses are calculated for all CO_2-EOR projects.

Equation 9

$$\begin{aligned} \text{CAPEX [M€]} &= 23.2 \text{ [M€]} * \text{number of injection wells} + 9.28 \text{ [M€]} * \text{number of production wells} \\ &\quad + 23.2\text{[M€]} * \text{maximum annual throughput of } CO_2 \text{ for recycling facility } [\frac{\text{Mt}}{\text{y}}] \end{aligned}$$

[44] $€_{2008}$ price level

[45] According to an industry expert, these numbers can vary substantially because of the duration of the project and differ on a case by case basis. The estimations for capital expneses are in line with NOGEPA (2009) and Mendelevitch (2014).

[46] GBP £ is converted to € using the conversion rate (€1.16/£) that is consistently used for the CAPEX estimations in Element Energy (2012)

Table 8-6 shows the capital expneses for all the fields, based on injection and production wells and CO_2 recycling facilities.

Table 8-6: CAPEX for fields A-G

Fields	CAPEX (M€)
A	791
B	279
C	535
D	482
E	259
F	1500
G	756

8.7.2 Operational expenses

Operational expenses are divided into fixed operational expenses and variable operational expenses. The fixed operational expenses are annual costs that need to be made even when there is no CO_2 injected or oil produced. These are costs for the offshore facilities and wells and include the costs for operation and inspection, maintenance, logistics, monitoring etc. The (annual) fixed operational expenses are assumed to be 5% of the capital expenses (Holt et al., 2009). The operational expenses for the seven fields are listed in Table 8-7.

Table 8-7: Fixed OPEX

Fields	Fixed OPEX (M€/y)
A	40
B	14
C	27
D	24
E	13
F	75
G	38

Variable operational expenses are the costs that vary according to the actual operations on the platforms. Therefore, variable operational expenses depend on oil production, the recycling of CO_2 and CO_2 compression and injection (Mendelevitch, 2014). Variable operational expenses for oil production are 12.1 M€/Mt CO_2 injected (BERR, 2007). For CO_2 recycling, the variable operational expenses are 5.2 M€/Mt CO_2 recycled (Gozalpour et al., 2005). For CO_2 compression and injection, the variable operational expenses are 8.7 M€/MtCO_2 (Gozalpour et al., 2005). Equation 10 shows how the variable operational expenses are calculated.

Equation 10

$$\text{Variable OPEX}\left[\frac{\text{M€}}{\text{y}}\right] = 12.1\left[\frac{\text{M€}}{\text{y}}\right] * \text{CO}_2\text{ injected }\left[\frac{\text{Mt}}{\text{y}}\right] + 5.2\left[\frac{\text{M€}}{\text{y}}\right] * \text{CO}_2\text{ recycled }\left[\frac{\text{Mt}}{\text{y}}\right] + 8.7\left[\frac{\text{M€}}{\text{y}}\right] * \text{ CO}_2\text{injected}[\frac{\text{Mt}}{\text{y}}]$$

8.7.3 Tax

A tax is levied on the oil profits. Taxes for oil and gas are complex and differ from low carbon technologies. To include the tax level for oil revenues when applying CO_2-EOR, key figures are adapted from Element Energy (2012), see Table 8-8. Most of the oil fields in the North Sea are located in the Norwegian, UK and Danish sector. These values are composed from corporation tax, supplementary charges and special taxes. Note that these taxes substantially differ from the US situation, e.g. a royalty rate of 18.5% (US Department of Energy, 2014).

Table 8-8: Overview tax rates for oil profits (Element Energy, 2012)

Sector	Tax level (%)
Norway	78%
United Kingdom	81%
Denmark	64%

In the alpha version of the simulation, a tax level of 10% is assumed.

9 Input for PSS: scenario parameters for CO_2-EOR

This chapter gives an overview of the scenarios for the oil market price and CO_2 market price. It is expected that the uncertainty of the oil market price and the CO_2 market price influences the CO_2-EOR project valuations.

9.1 Revenues from CO_2-EOR

Total revenues from CO_2-EOR are calculated by summing the oil revenues (dependent on the market price for oil) and the credits obtained from sequestering CO_2 (dependent on the market price for CO_2 credits).

9.1.1 Oil market price

The scenario parameters for the oil market prices are based on the forecasts by the Energy Information Administration (US Department of Energy, 2013) for the period 2020-2040. The forecasts from the European Commission (2013) and IEA (2012b, 2013b) lie within the boundaries of the high and low forecasts of the Energy Information Administration. The high and low forecasts are extrapolated from 2040 to 2050. Although there is a difference between the two benchmarks for the US market (West Texas Intermediate) and the European market (Brent), we assume that these are identical.

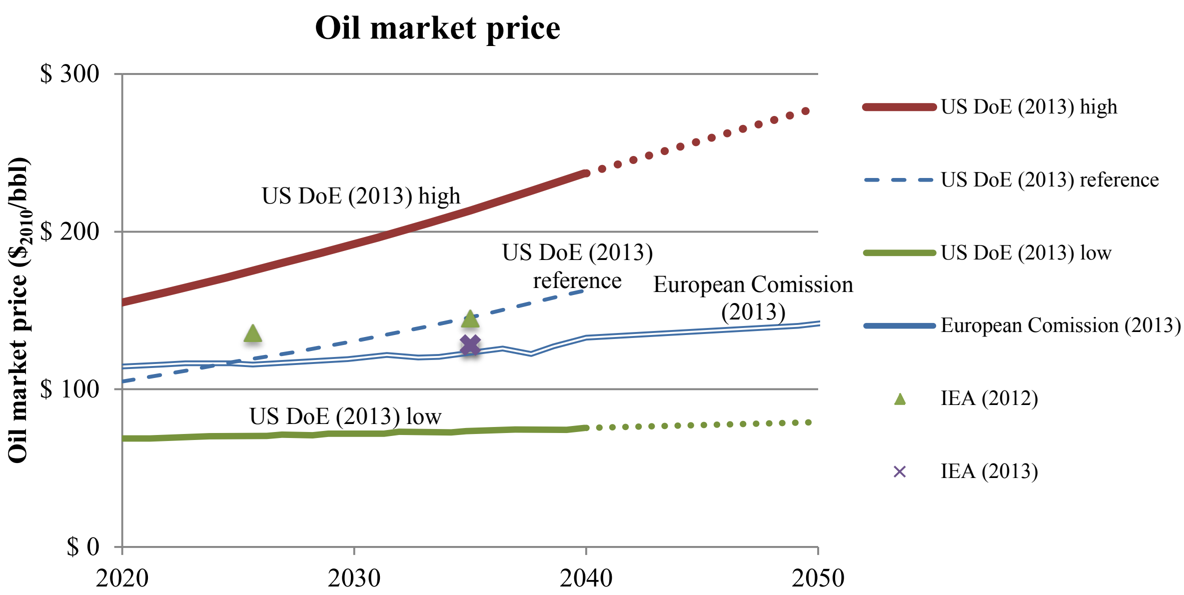

Figure 9-1: Oil market price forecasts from 2020-2050. High and low scenarios from US DoE are extrapolated from 2040 to 2050 (European Commission, 2013; IEA, 2012b, 2013c; US Department of Energy, 2013)

The oil market price varies between the low and high scenario by US Department of Energy (2013) as shown in Figure 9-2.

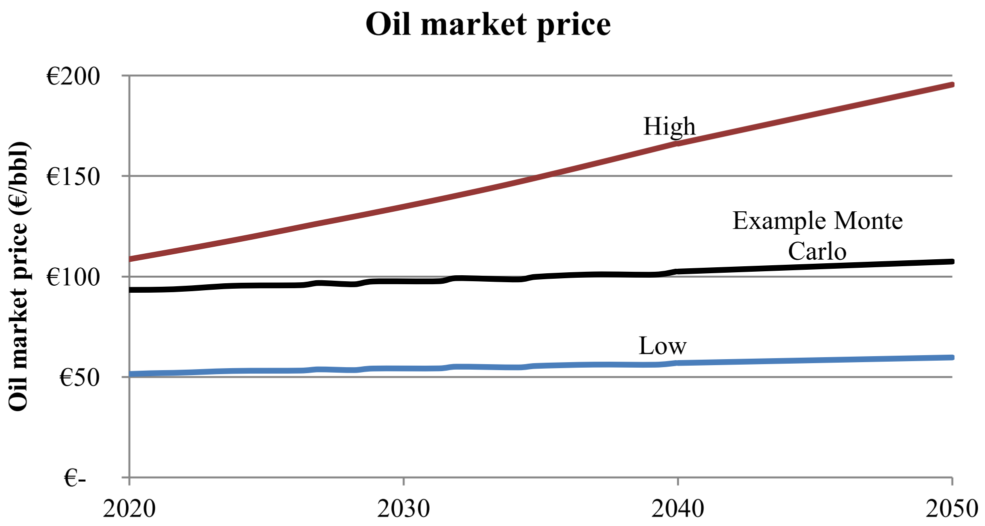

Figure 9-2: Oil market price (minimum and maximum) from 2020-2050 including an example Monte Carlo run

9.1.2 CO_2 market price

The CO_2 market price[47] is the market price for a carbon credit. The CO_2 market price is derived from the carbon price forecast from European Commission (2013). The carbon price is projected to increase to €$_{2010}$100/tonne in 2050. The low and high scenario for the CO_2 market price are derived[48] from IPCC (2014). The resulting low and high scenarios are indicated in Figure 9-3. The CO_2 market price variation is used as a stochastic parameter in PSS. Hence, the CO_2 market price varies from €6-50 in 2020, to €34-250 in 2050.

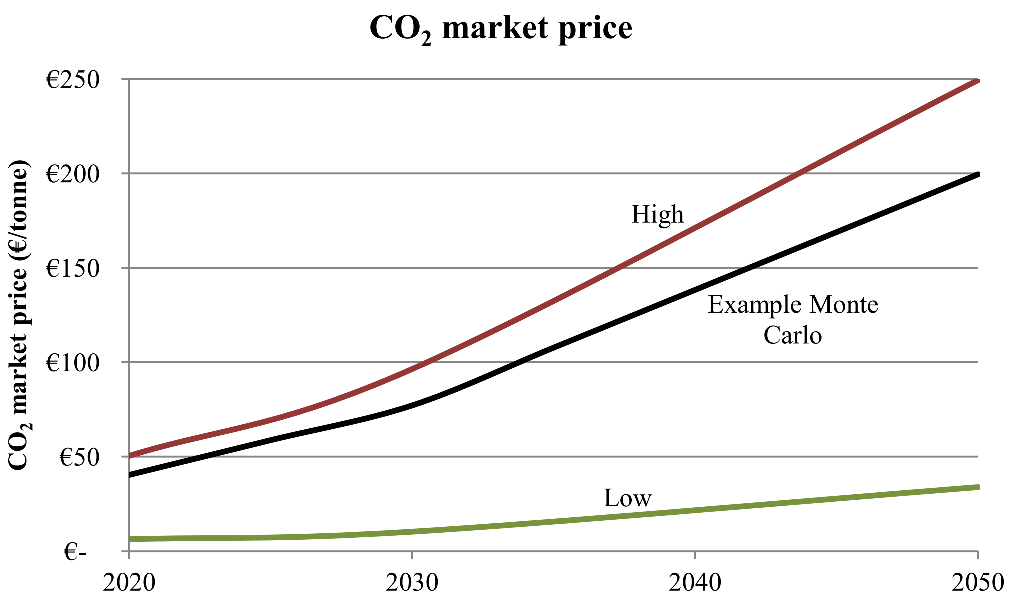

Figure 9-3: CO_2 market price scenario based on the lowest and highest 25% of all scenarios assessed in IPCC (2014)

[47] The CO_2 market price should not be confused with the costs for capturing and transporting CO_2

[48] 191 scenarios are box-plotted in IPCC (2014) and grouped into idealized implementation scenarios. For this study, the 25% highest and 25% lowest scenarios are used for the high and low scenario of the CO_2 market price. The CO_2 market price is converted into €$_{2010}$ using the exchange rates from X-Rates (2014)

This thesis assumes that the CO_2 market price adds to the revenues of the CO_2-EOR operator when the CO_2 market price exceeds the capture cost for the CO_2 source. When the capture cost exceeds the CO_2 market price, these are the costs for the CO_2-EOR operator to purchase the CO_2. This assumption is in line with Mendelevitch (2014).

The CO_2 market price and oil market price are scaled according to a pre-defined path. This scaling happens by stochastically setting a scaling factor. Therefore, every Monte Carlo run, a random path for the parameters are chosen, but based on a pre-defined pricing scenario.

PART D: RESULTS AND ANALYSIS

10 Results

The literature review on CO_2 transport and CO_2-EOR has resulted in a methodological framework for the simulator. Therefore, one of the outcomes of the research process is a working version of the PSS IV simulator. The simulator is used to identify important parameters, knowledge gaps and pitfalls. A database with geological (e.g. EOR performance), techno-economic (e.g. investments based on technological capacity) and scenario (e.g. oil market price) parameters are added to the simulator.

Software development of PSS at the Geological Survey of Belgium can be divided into four phases. The primary development and testing takes place in the alpha phase. The software is tested to identify bugs in the code and the database still needs to be validated. In the beta phase, the software itself runs smoothly and the input data is extensively validated. The main question in the beta phase is whether the results are realistic. In the gamma phase, large-scale runs can take place and different scenarios are run to test the different outcomes. In the delta phase, the software can be used for commercial purposes. This means that PSS IV could be used for actual decision making for CO_2-EOR operators.

The current version of PSS IV is still in the alpha phase. That means that the outcome cannot be used to form an investment decision. However, the outcomes provide a valuable start for assessment of the offshore cluster of potential CO_2-EOR projects. The CO_2-EOR technology is activated under different circumstances for all seven simulated primary producing oil fields. The simulation produces stable and realistic overall results.

10.1 General results

The results for this thesis are produced with the alpha version of PSS IV. The stochastically set oil market price and the CO_2 market price influence whether CO_2-EOR is activated. The EOR performance (reservoir's oil recovery potential, i.e. the recovery rate as a fraction of the OOIP) also influences the profitability of the reservoir because it determines the amount of barrels that are extracted using CO_2-EOR.

To analyze the outcome of the simulations with regard to the timing of either *stopping primary production*, retrofitting to *CO_2-EOR* and *stopping CO_2-EOR*, a set of graphs have been constructed based on the raw output files.

The lay-out of some of the graphs are similar to Figure 10-1: a density plot for the Monte Carlo runs shows the simulated time (2010-2050) on the x-axis. On the y-axis, the parameter of interest is shown (in this example the oil market price, expressed in €/bbl). The graph shows the variation of the oil market price over time. The oil market price follows a path to reach a value between €60 and €196/bbl in 2050. The oil market price is scaled stochastically, which means that the simulator sets a path between the pre-defined upper and lower values over time. Due to a rounding issue for the oil market price, the paths are discrete. Therefore, several paths overlap which is reflected in the denser (darker) dots in the graph. This rounding issue is only minor because the variation in itself is not influenced, thereby allowing to assess the impact of relatively high and low oil market prices on the activation of *CO_2-EOR*.

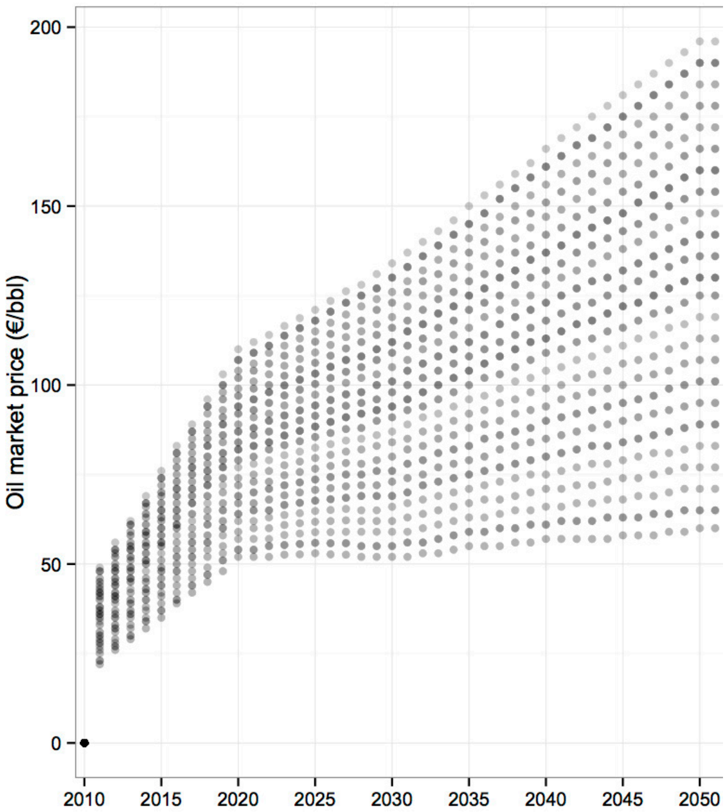

Figure 10-1: Monte Carlo runs for the oil market price. The number of occurrences is reflected by the density of the dots, the darker shade of grey indicates more occurrences. The oil market price follows a path that is scaled stochastically between the scenario boundaries as described 9.1.1 (e.g. between €60 and €200/bbl in 2050.)

Figure 10-2 shows a graph for the difference in project status for the simulations in that year. The project status can be: *primary production*, *stopped primary production*, *CO_2-EOR*, and *stopped CO_2-EOR*. Once a project stops (either by *stopped primary production or stopped CO_2-EOR*) the project cannot be made operational again. The y-axis shows the number of Monte Carlo iterations for all projects. Approximately 1700 simulations are shown here for all fields, which means around 250 simulations per field.

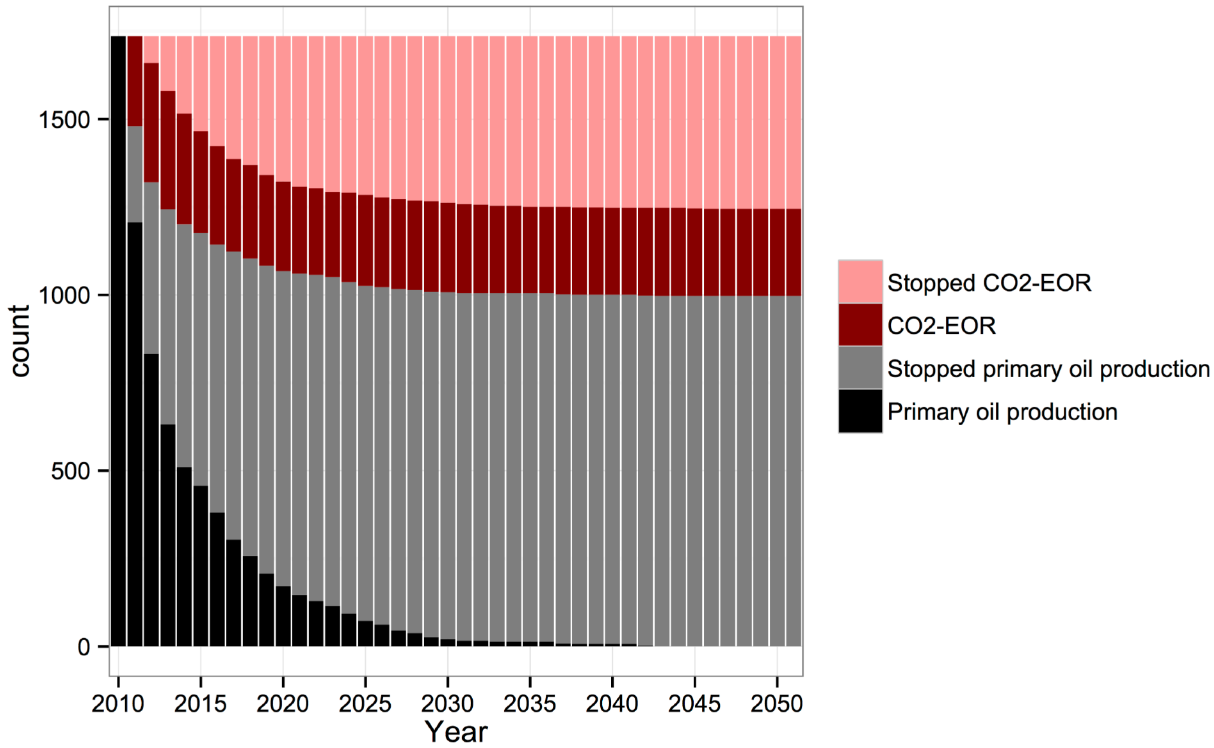

Figure 10-2: Bar chart for the status of the simulated projects: primary production, stopped primary production, CO_2-EOR, and stopped CO_2-EOR. The graph shows the share of the project status in a given year. The graph shows the sum of all simulations for the seven fields. For instance, in year 2010, all project statuses are primary production. In 2020, the status share for primary production, stopped primary production, CO_2-EOR, and stopped CO_2-EOR are 13%, 50%, 14% and 23% respectively.

The projects are assumed to have been in *primary production* since their startup in 2000. When the simulation starts in 2010, a fast decrease in *primary production* can be seen. After two years, only 50% of the simulations are still in *primary production*. This is caused by the decreasing oil revenues – because of the declining production curve of *primary production* curve – resulting in low project values. The number of projects that are stopped from *primary production* increases until 2030 and then flattens out. A substantial share of the projects (15%) is retrofitted to *CO_2-EOR* in 2011. This implies that *CO_2-EOR* can be profitable in the current simulations with the current set of techno-economic parameters.

It is also visible (Figure 10-4) that most projects are quickly (within 5 years) retrofitted to *CO_2-EOR* and then also quickly stopped. This could imply that *CO_2-EOR* is a profitable option but when the EOR production has peaked, the project is stopped again. This could be the influence of the investment decisions based on real options which has been used in the simulations: a project can be started but also stopped when the profitability appears to be less positive then expected at first. This could be caused by a lower than expected CO_2 market price, oil market price or disappointing geological performance, i.e. a low amount of barrels than can be produced using *CO_2-EOR*. At this moment, it is not possible to pinpoint the cause of the decision to retrofit quickly to *CO_2-EOR* and then stopping *CO_2-EOR*. Further research is required to confirm this result and reveal the main drivers.

In 2011, there are no projects that are stopped from *CO_2-EOR*, because that is the first year that *CO_2-EOR* is possible. The amount of stopped projects from *CO_2-EOR* builds up until 2020 and then stabilizes.

Figure 10-4 shows the plots for the individual fields A-G. All fields indicate a retrofit to *CO_2-EOR*, which means that *CO_2-EOR* can be profitable for the fields with different sizes, geological uncertainties and techno-economic parameters. The plots also indicate that the smaller the field, the more *CO_2-EOR* is applied: B shows more *CO_2-EOR* than C, and C shows more *CO_2-EOR* than A. E shows slightly more *CO_2-EOR* than D and G shows more CO_2-EOR projects than F.
A possible explanation is the higher requirements for CO_2. When capturing CO_2 from an industrial source, the cheapest CO_2 is addressed. When more CO_2 is required, you move along the capture cost curve, which increases the average costs per captured tonne of CO_2. This is illustrated in Figure 10-3.

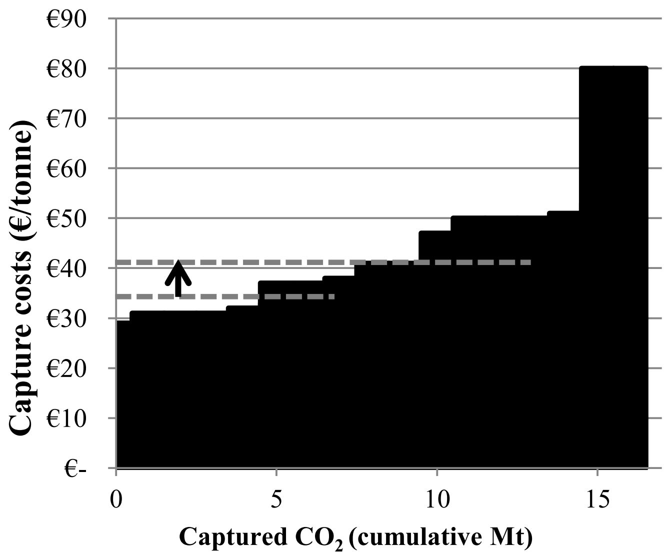

Figure 10-3: Capture cost curve for Antwerp. The dotted lines show the average capture costs per tonne CO_2 for the amount for field G (6.9 Mt/y required, in this example at 33 €/tonne CO_2) and field F (13.7 Mt/y required, in this example at a price of 40 €/tonne. This implies that the average capture costs for field F are 20% more expensive than for field G, thereby reducing the CO_2-EOR project value for field F.

When the amount of CO_2 is not sufficient, other CO_2 hubs need to be addressed. This implies additional investments in transport infrastructure which also increases the costs.
A second explanation can be the risks than can be higher for the larger project, while two smaller projects offer more flexibility and therefore increase the real option value for the individual project. This is because multiple projects in a cluster can use the same infrastructure and therefore benefit from the economies of scale. The smaller fields are favorable because they are clustered in the same location. It is expected that a single small field is less valuable than a larger field in which economies of scale can be more easily reached. Further research is necessary to make a comparison between a small field in a cluster and a single small field.

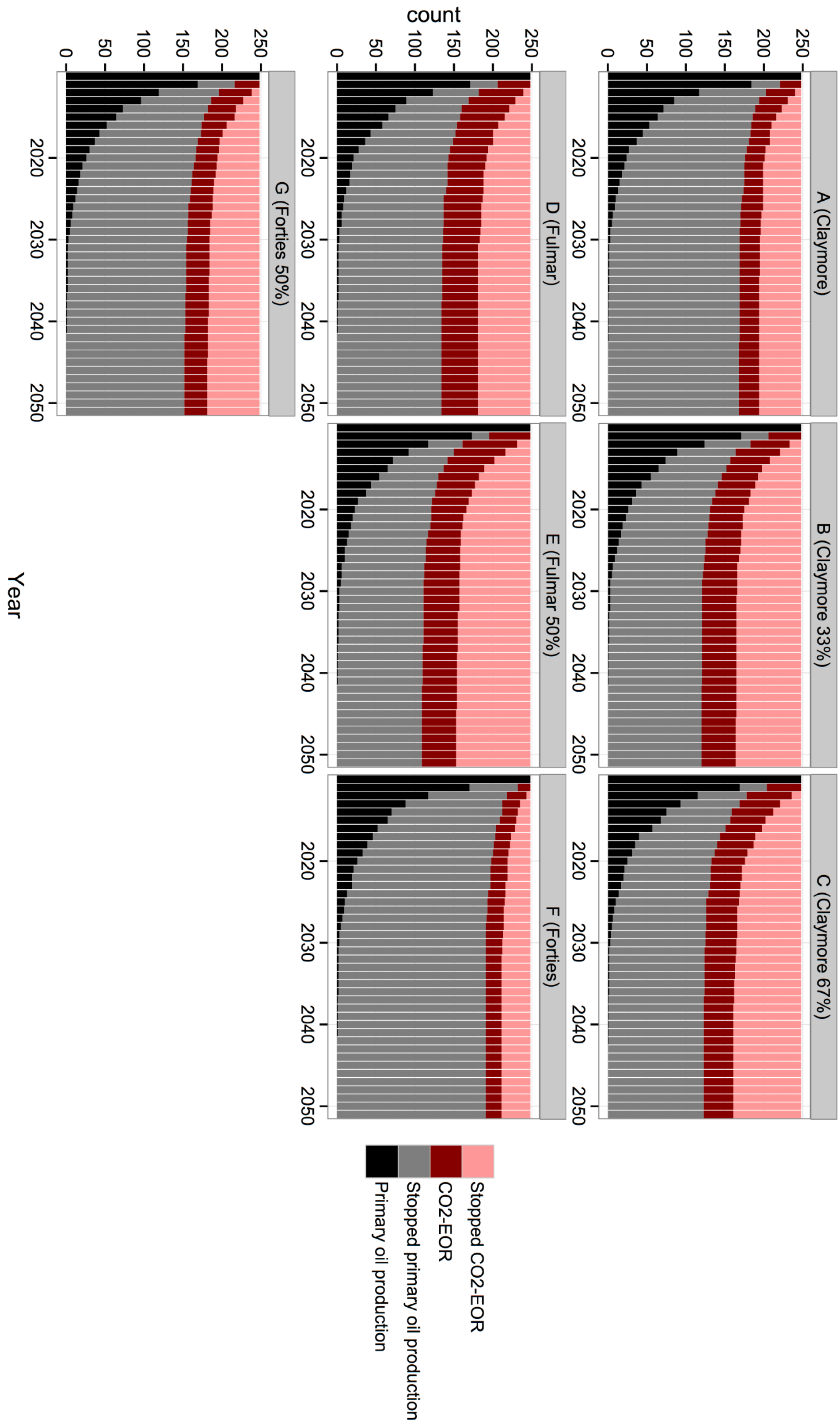

Figure 10-4: Bar chart for each of the seven fields (A-G) with the project status for the simulation: primary production, stopped primary production, CO_2-EOR, and stopped CO_2-EOR. The graph shows the share of the project status in a given year. For instance, in year 2010, the project status for all simulations for each of the fields are primary production.

10.2 Oil market price

The influence of the oil market price on the timing and values of *CO_2-EOR* projects is analyzed by looking at the density plots for the status of the simulated projects. The density plots for all fields are shown in Figure 10-6 and Figure 10-7 shows the density plots for the individual fields A-G.

To explain the analysis, we take a closer look at field E. The plots for field E are easier to interpret because they clearly show the observed findings. Figure 10-5 shows the density plots for field E for the project status *Primary oil production* and *CO_2-EOR*.

A high amount of simulated projects have the project status *primary production* and this decreases over time. Around 2035, almost all *primary production* projects are stopped because of decreased production (i.e. the declining phase in the lognormal approach for simulating the production curves). This is also visible in the plots in Figure 10-7. After 2042, there are no projects that have the *primary production* status. The paths have a positive slope, because the oil market price increases according to the stochastically scaled parameter for the oil market price (introduced in section 9.1.1 and the Monte Carlo loops for the oil market price are shown in section 10.1).

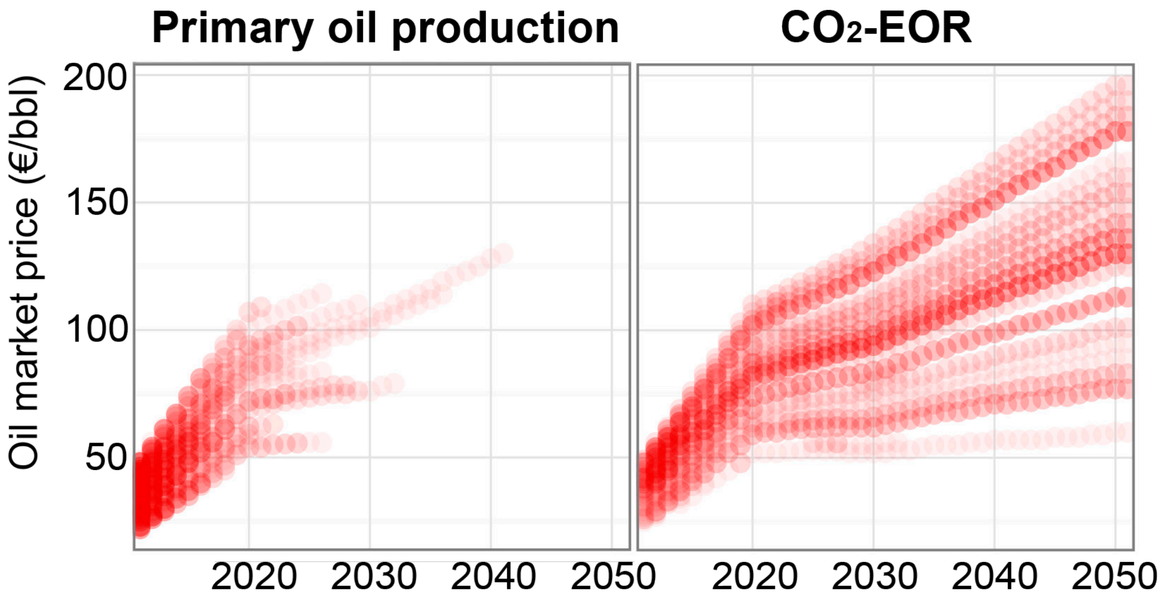

Figure 10-5: Two plots for field E. The density of the plots (darker red means more simulated projects in that status) indicate the number of simulated projects that have the status primary oil production (left) and CO_2-EOR (right).

Primary production continues for a longer period (until 2035) when the oil market price is relatively high (€75/bbl or higher), as compared to lower oil market prices when *primary production* ends around 2020-2025. A high oil market price extends the period of profitability for the *primary production*, because the economic limit is reached later. An alternative explanation is that retrofitting to *CO_2-EOR* is not favored as compared to stopping the *primary production*. This could be because there is a real option value in waiting to retrofit to *CO_2-EOR* and therefore the period for *primary* *production* is extended. This extension is because of the future value of retrofitting to *CO_2-EOR*. This future value, or value of waiting is because of the availability of the option to go to *CO_2-EOR*.

A high oil market price for *stopped CO_2-EOR* indicates that a relatively high oil market price is required for *CO_2-EOR*. This is deduced from the fact that a project can only be stopped from *CO_2-EOR* when *CO_2-EOR* was operational. The far majority of *CO_2-EOR* projects are operational at oil market prices higher than €75/bbl.

For small fields (B and E, see Figure 10-7), the oil market price is a more sensitive parameter for *CO_2-EOR*. For the larger fields (A, C, D), there are less *CO_2-EOR* projects. F (large field) has less *CO_2-EOR* than G (half the size of F). This also holds for field A, B and C. The smaller the field, the more *CO_2-EOR* is applied. Such an effect can indicate that insufficient CO_2 (at reasonable costs) is available from the CO_2 hub. This could potentially be an important result and message regarding the implementation of *CO_2-EOR* in the North Sea area. However, given the alpha status of PSS IV and the complexity of simulating the interaction of seven fields that compete for CO_2, the reliability of PSS IV needs to be verified before drawing final conclusions. At the moment of writing, these checks are being performed and are expected to be published in the near future.

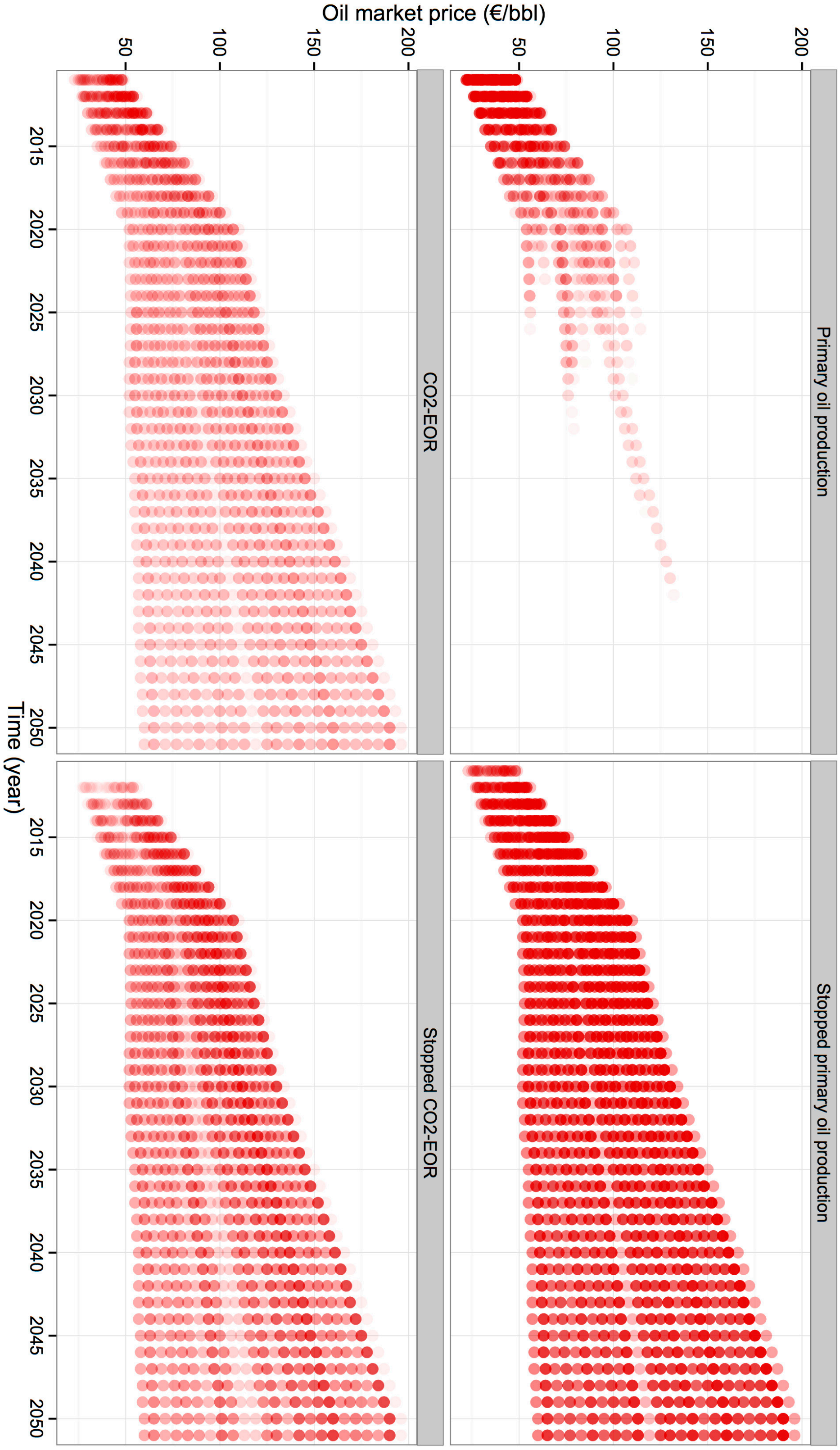

Figure 10-6: Density plots for the status (primary oil production, stopped primary oil production, CO_2-EOR, or stopped CO_2-EOR) totaled for the seven fields over the simulated time period. The oil market price is the parameter of interest and shown on the y-axis. The density of the plots (darker red means more simulated projects in that status) indicate the number of simulated projects that have the concerning project status.

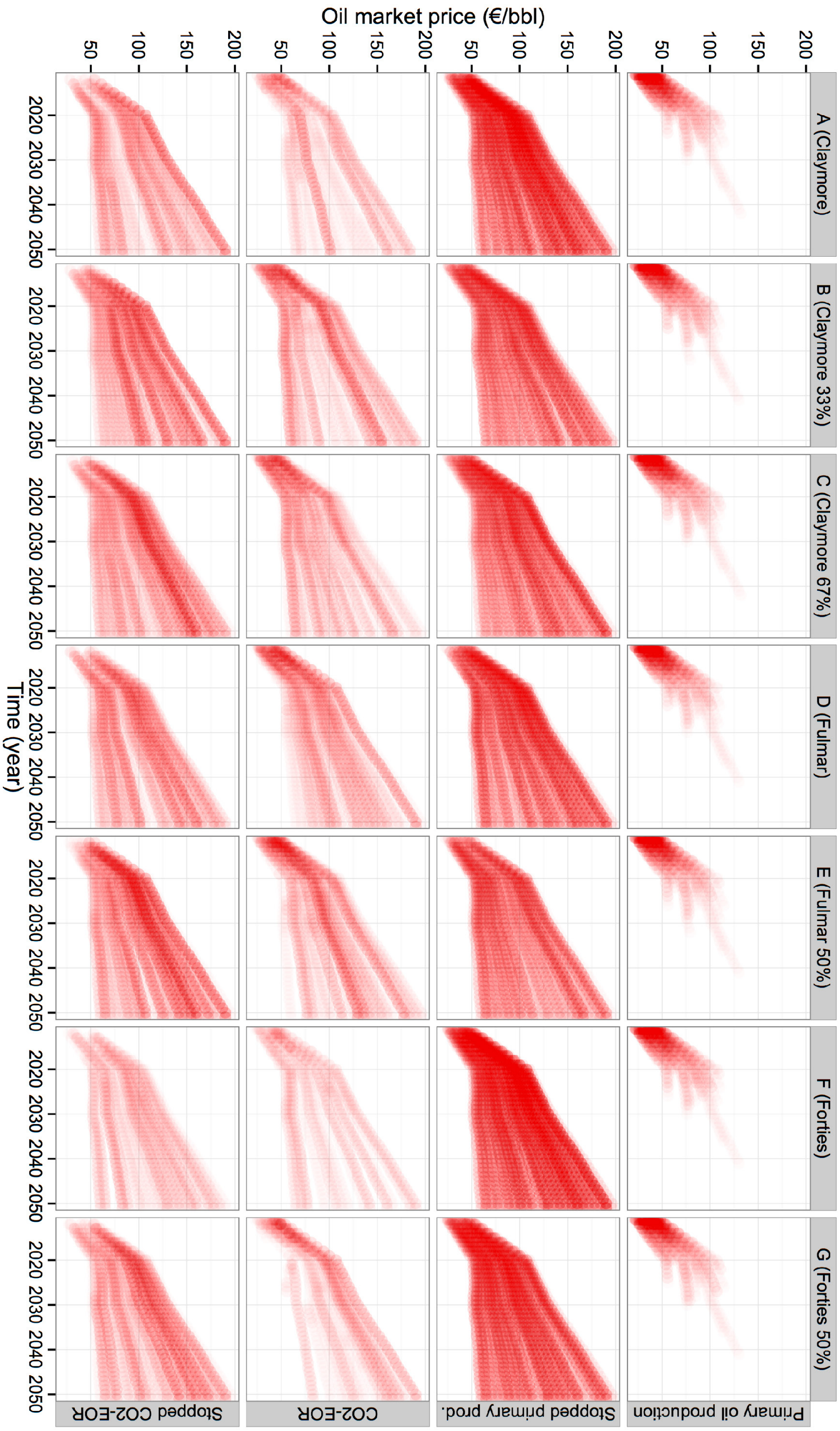

Figure 10-7: Density plots for the status (primary oil production, stopped primary oil production, CO_2-EOR, or stopped CO_2-EOR) for each of the seven fields (A-G) over the simulated time period. The oil market price is the parameter of interest and shown on the y-axis. The density of the plots (darker red means more simulated projects in that status) indicate the number of simulated projects that have the concerning project status.
For instance, there are more simulated projects with the status CO_2-EOR (denser plot) for field B than for field A.

10.3 CO_2 market price

The graphs in Figure 10-8 and Figure 10-9 show the paths for the CO_2 market price that are simulated by the Monte Carlo runs. The CO_2 market price follows a path between €0-20/tonne in 2010 to €40-250/tonne in 2050. The pathways are marked in red when the according status is active.

Because the analysis did not reveal any meaningful relationship between the CO_2 market price and the activation of *CO_2-EOR* projects which is to be expected, an in-depth study in the PSS IV code followed. A major flaw in the calculations was identified. Therefore, the graphs do not show the expected relation between the CO_2 market price and the profitability of *CO_2-EOR* projects. The absence in the code was discussed with the developers and the mistake was identified. At the moment of finalizing this thesis, the new results were not ready yet.

It is expected that the CO_2 market price has less impact on the valuation of *CO_2-EOR* than the oil market price. However, a high CO_2 market price can increase the profits for a EOR project because of the CO_2 ETS revenues. *CO_2-EOR* benefits from CO_2 ETS revenues because the CO_2 that is injected and not produced again, is assumed to be stored in the reservoir.

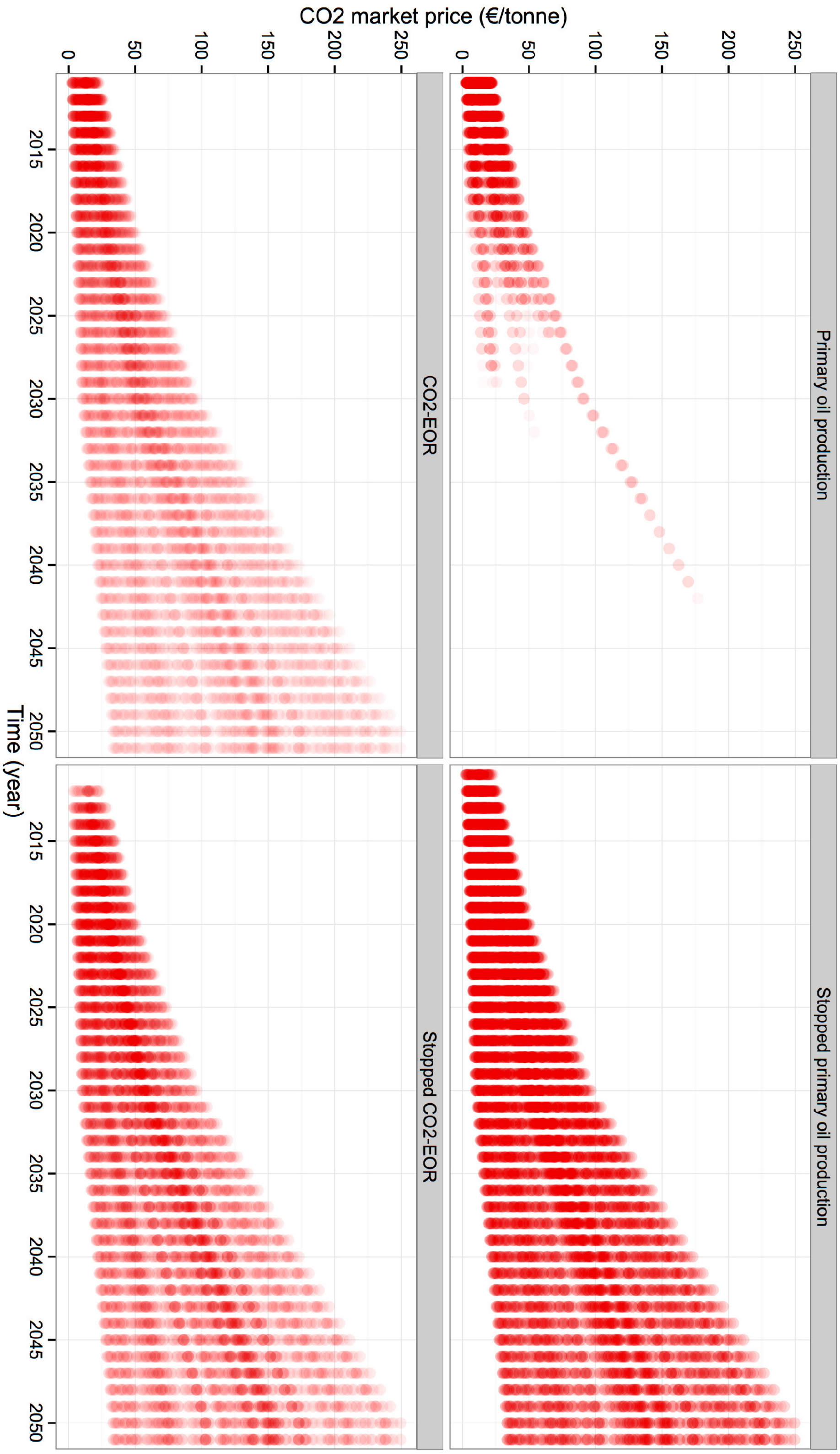

Figure 10-8: Four graphs for the status (primary oil production active or stopped, CO_2-EOR active or stopped) totaled for the seven fields over the simulated time period. The CO_2 market price is the parameter of interest and shown on the y-axis. The density of the dots indicates the number of occurrences. For instance, there are more projects stopped from primary production (top-right graph) than are retrofitted to CO_2-EOR (bottom-left graph).

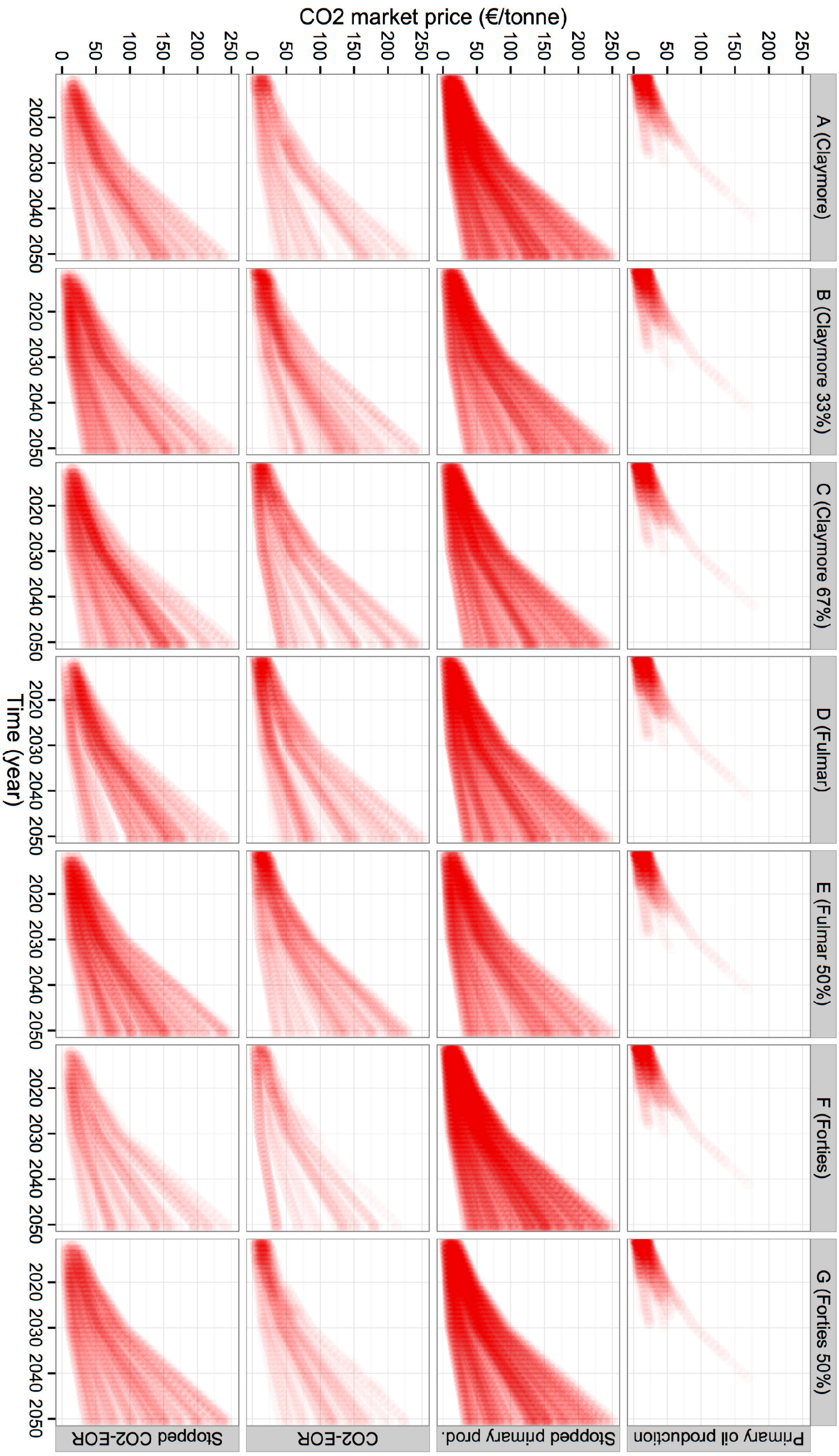

Figure 10-9: Four graphs for the status (primary oil production active or stopped, CO_2-EOR active or stopped) for each of the seven fields (A-G) over the simulated time period. The CO_2 market price is the parameter of interest and shown on the y-axis. The density of the dots indicates the number of occurrences. For instance, there is more CO_2-EOR (denser plot) for field B than for field A.

10.4 Geological uncertainty: recovery rate CO_2-EOR

The recovery factor *for CO_2-EOR* determines the amount of oil that can be recovered during *CO_2-EOR* as a fraction of the OOIP. The recovery factor is stochastically set, which allows for analyzing the impact of this parameter on the activation of *CO_2-EOR*.

Figure 10-10 shows a density plot for field E over the simulated time period. The density plot indicates the number of *CO_2-EOR* that are active in that year. The graph shows that there are more *CO_2-EOR* active in the beginning when the recovery factor is high. This implies that a high expected amount of oil that can be extracted, heavily influences the decision to retrofit to *CO_2-EOR* from *primary production*. When the recovery factor is low, *CO_2-EOR* is activated later in the simulations (from 2025-2050). This result is to be expected and shows that simulator produces realistic results regarding this aspect.

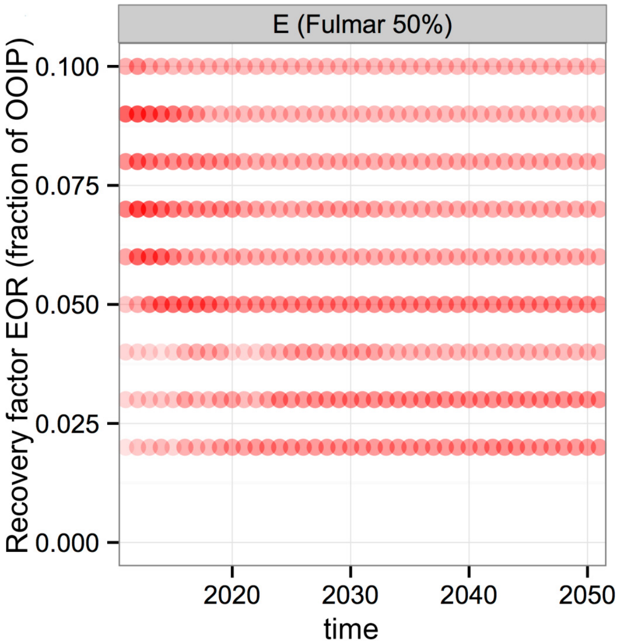

Figure 10-10: A density plot for field E (Fulmar 50%) over the simulated time period. The density plot indicates the number of CO_2-EOR projects that are active in that year.

Discounting can also influence the early activation of *CO_2-EOR*. The returns in the beginning have a higher value because the future revenues are discounted and thus lowered. Also, negative effects at the reservoir level are not taken into account: early activation of *CO_2-EOR* can reduce the amount of oil that would have been produced using *primary production*, which is not an optimal economic decision. Figure 8-11 (in chapter 8) indicates this area in orange, in which the primary oil production is reduced, because *CO_2-EOR* is activated.

Figure 10-11 shows the density plots for all seven fields. There are more CO_2-EOR projects for the smaller (OOIP < 1000 M bbl) fields B, C, D and E as compared to A.

For all individual fields (except for major field F), a recovery rate higher than 0.05 (5% of OOIP), leads to early retrofitting from *primary production* to *CO_2-EOR*. This could be explained by the oil market price that increases over time according to the scenario. Although the recovery rate is low, the profitability of projects increase because the oil market price increases over time according to the scenario.

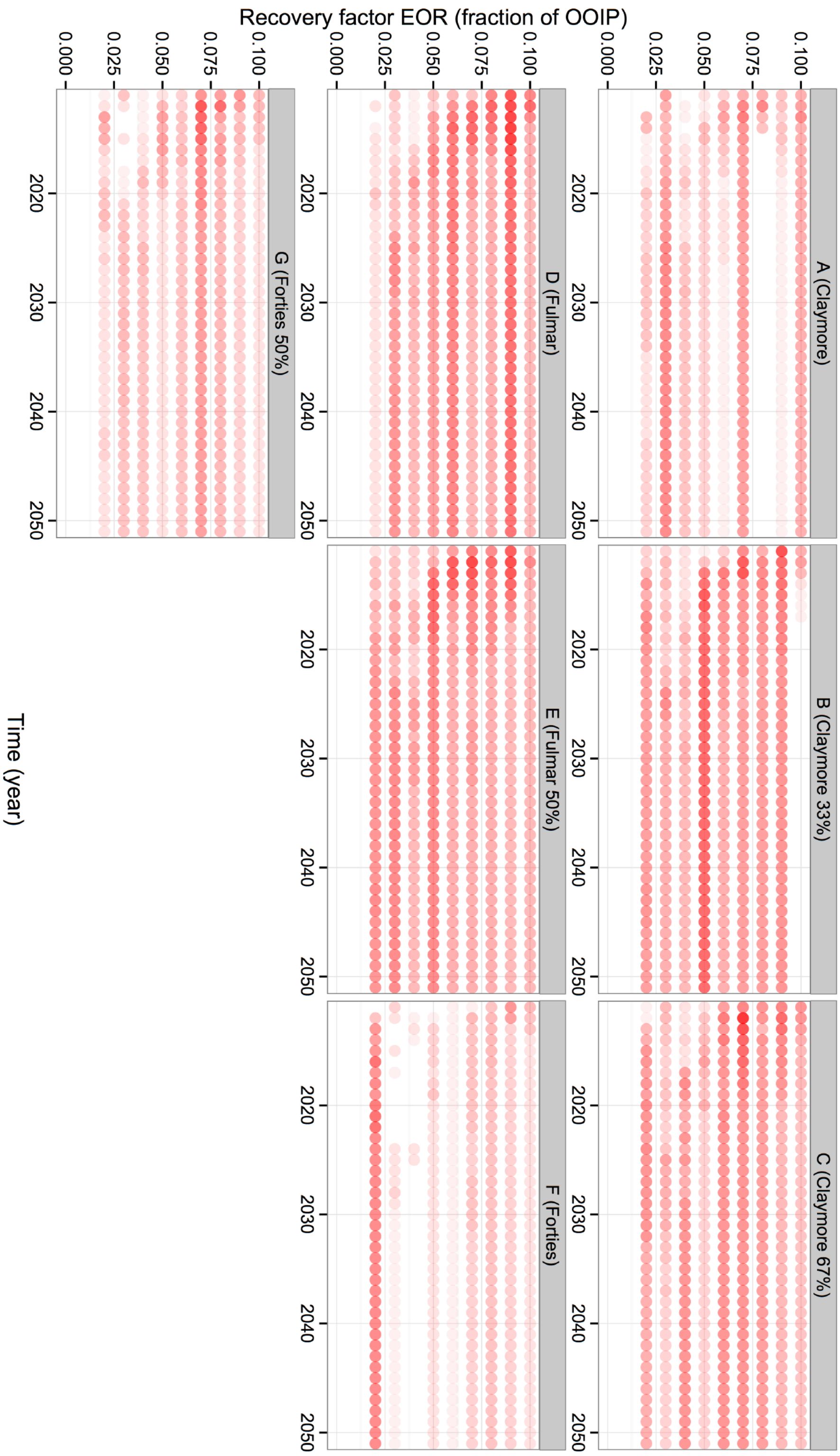

Figure 10-11: A graph for each of the sevens fields (A-G) over the simulated time period. Only the CO_2-EOR are shown and the density of the dots indicates the number of CO_2-EOR projects that are active in that year. For instance, for field D (Fulmar) there is more CO_2-EOR (denser plot) when the Recovery factor is high as compared to when the Recovery factor is low

10.5 Cost and revenue structure

The annual costs and revenues are shown in Figure 10-12 for field A, B, C and D and in Figure 10-13 for field E, F, G. The oil revenues and CO_2 costs follow the paths of lognormal curves. This is because for the CO_2, the amount of CO_2 injected (and therefore costs) follow a lognormal curves. The delay in oil production is visible – oil revenues start after the peak of CO_2 costs. The oil revenues follow a lognormal curve, because the oil production in number of barrels per year follow the lognormal curves as explained in section 8.3. The CO_2 ETS revenues increase over time and later stabilize. Although the CO_2 is partially recycled – thus reducing the demand – the CO_2 market price increase over time according to the scenarios as described in section 9.1.2. Later in time (2035-2050), the EOR performance is so low that there is a high CO_2 supply (and therefore high CO_2 ETS revenues) but very low oil revenues.

The oil revenue peaks are approximately at the same level (between 800-950 M€), while the amount of oil that can be extracted using *CO_2-EOR* substantially differs: field F is 8.7 times bigger than field B, but the average oil revenues hardly differ. A possible explanation is that the numbers are averaged and field B is retrofitted more to *CO_2-EOR* than field F. It also shows that the costs for pipelines are substantially higher for field F than for the rest of the projects. This is due to the high CO_2 requirements (13.7 Mt CO_2/year) for field F which require pipelines with a larger diameter.

The lognormal pattern in the oil revenues and CO_2 costs show a second bump. This can be explained by an increase in *CO_2-EOR* project activation after 15-30 years when the oil market price increases and a high amount of *CO_2-EOR* projects that are started in the first years and quickly shut down again. The main costs/revenues follow a sequence. For instance, for field A, the CO_2 costs peak around 2014-2016, the oil revenues peak around 2017-2019 and the CO_2 ETS revenues are dominant from 2028 onwards. CO_2 costs peak in the beginning because the CO_2 needs to be purchased and needs to be injected for two years, until the oil is produced from the production well. The CO_2 ETS revenues take over because the CO_2 market price increases over time. The *CO_2-EOR* operation continues when the real option value to continue is higher than stopping the operation. Therefore, broadly speaking, when the CO_2 ETS revenues offset the costs for the CO_2 capture, transport and injection, *CO_2-EOR* operation continues although the oil revenues itself are relatively low.

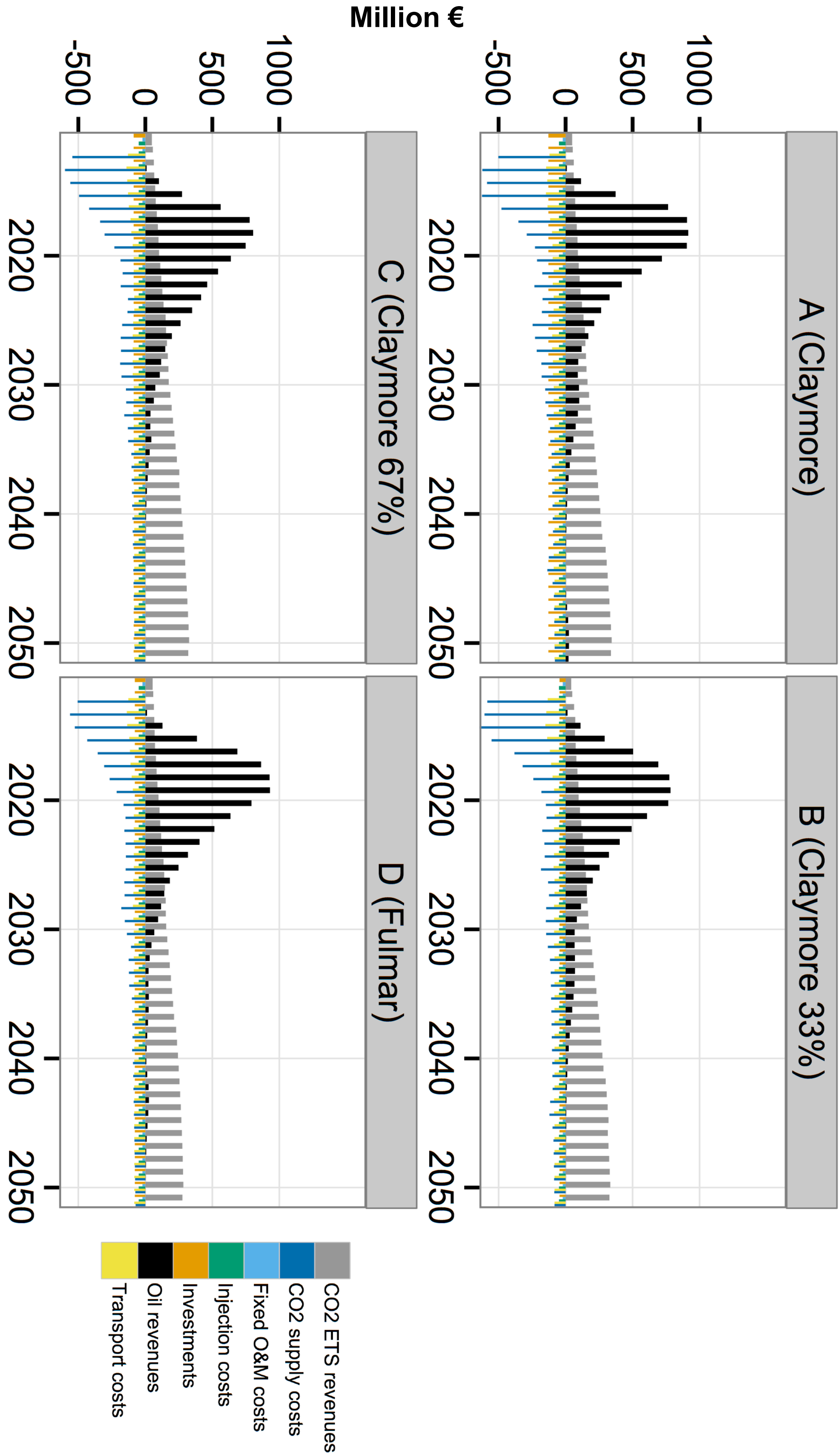

Figure 10-12: Graphs for costs and revenues for field A, B, C and D. The graphs show the annual costs or revenues for the different categories. For instance, the CO_2 supply costs are high during 2010-2025 while the CO_2 ETS revenues are increasing over time.

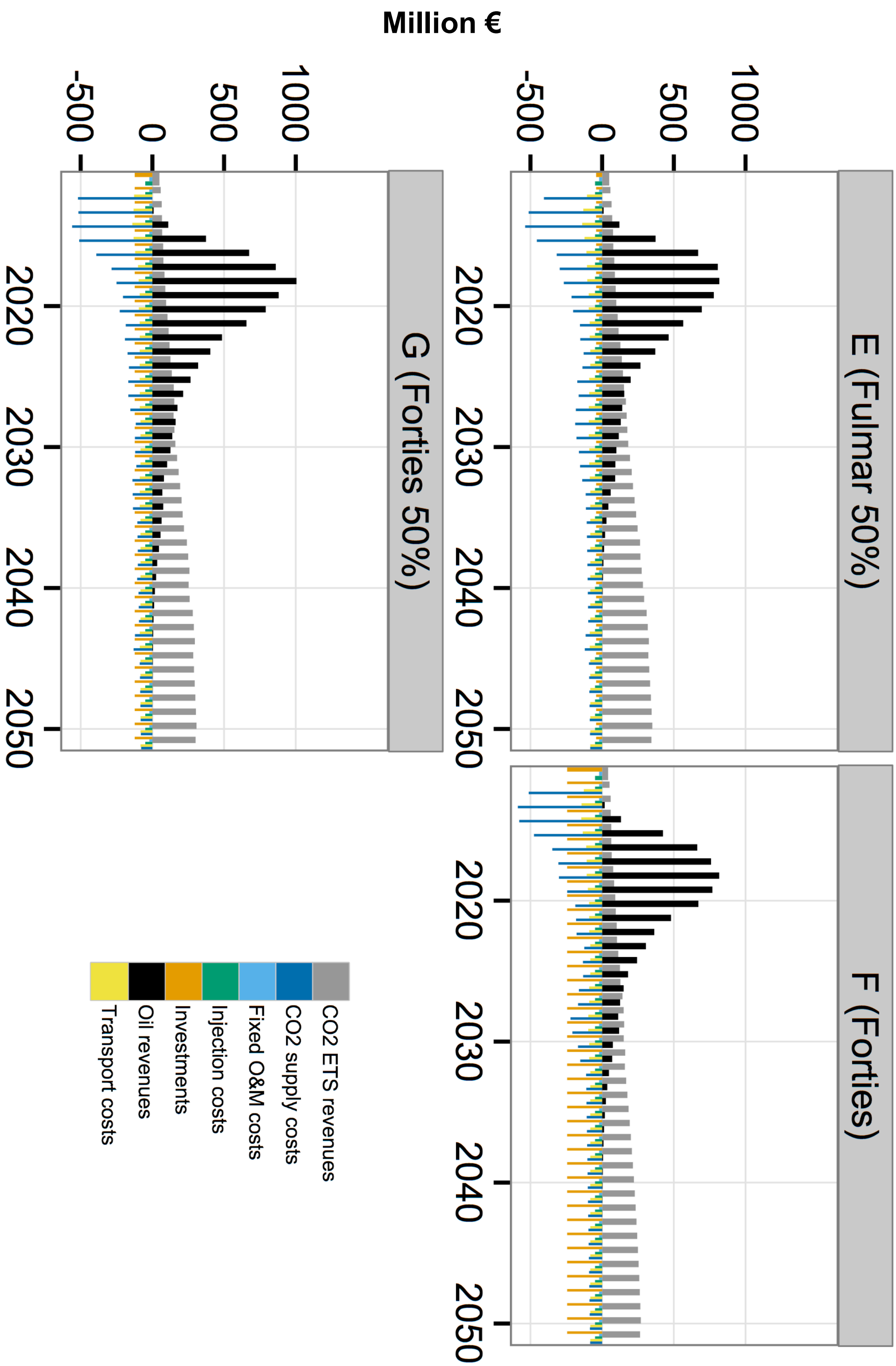

Figure 10-13: Graphs for costs and revenues for field E, F and G. The graphs show the annual costs or revenues for the different categories. For instance, the CO_2 supply costs are high during 2010-2025 while the CO_2 ETS revenues are increasing over time.

11 Discussion

This chapter outlines the strengths and weaknesses of the study and suggests directions for further research.

11.1 Strengths

PSS IV is the first model that introduces the concept of limited foresight in CO_2-EOR modeling by using stochastic parameters for the geological characteristics. A real option approach helps PSS IV to simulate more realistic decisions. The model is able to simulate the behavior of investors instead of forecasting or optimizing for a desired future outcome. The model can encourage the demonstration and full-scale deployment of CO_2-EOR projects. The study further improves the understanding of the potential for CO_2-EOR projects in the North Sea. The sound business case that arises when the geological characteristics, CO_2 market price and oil market price are taken into account, can stimulate the development of geological storage of CO_2. This contributes to mitigating global climate change by reducing the CO_2 concentration in the atmosphere. The study as a whole contributes to the knowledge base on using limited foresight in techno-economic models, because it outlines the practical use for real-world investment decisions.

11.2 Points for improvement

In the development of PSS IV, several simplifications have been made to speed up the simulation process. The costs to transport the CO_2 from the center of the cluster to the different fields (10 km) is not included. This has a minor influence on the total costs for CO_2 transport, because the distance of the trunkline between the CO_2 hubs and the center of the cluster ranges from 300 to 700 km. Moreover, the real option analysis is simplified by randomly selecting one of the numerous field configurations in the extremely large real option decision scheme (10^25 possibilities). The results appear to be robust, because little difference was observed when the number of Monte Carlo loops per field was increased from 200 to 450.

CO_2-EOR is primarily an oil producing technology, although it can also be used to store substantial (1-15 Mt/y) amounts of CO_2. It is debated in the academic and policy sphere whether CO_2-EOR operators can benefit from the CO_2 market price in an emission trading scheme investments (Mendelevitch, 2014). Therefore, this thesis uses an approach similar to Mendelevitch (2014) in which the costs for the CO_2-EOR operator for captured CO_2 are reduced according to the CO_2 market price. When the capture costs are higher than the CO_2 market price, the CO_2-EOR operator benefits from a lower purchase price for the CO_2. When the CO_2 market price is higher than the capture costs, the owner of the CO_2 source with capture facilities benefits from the surplus. Further research could investigate the impact of new regulations that influence the cost structure of CO_2-EOR, for example the European CCS directive. If the CO_2-EOR operator benefits from the CO_2 pricing incentive, it is expected that the CO_2 market price can influence the profitability but also the lifetime of CO_2-EOR projects, as is shown in the results from the simulations. Another research approach is to see how realistic behavior can be simulated for the negotiations between the CO_2 supplier and user and how these two parties benefit from the CO_2 ETS revenues. This approach is going to be explored by related research at Hasselt University.

The results should be interpreted with care, because the simulator need to be calibrated and validated. To calibrate the figures, more reliable information about the dynamics of CO_2 injection and offshore oil production is required. Assumptions are based on articles in peer-reviewed journals, but industry expertise could increase the validity of the figures. A lognormal approach is taken to simulate the curves of primary oil production and CO_2-EOR. To improve this estimation, actual production curves could be used or the production curves can be based on specific and detailed reservoir modeling, not a generalization of such an outcome. Calibration and validation of the model allows to improve the understanding of the timing of activation of offshore CO_2-EOR projects. To also fully accredit the economic advantage of additional project flexibility, ship transport needs to be calibrated for costs of realistic long-distance transport. The databases for ship transport costs are developed in this thesis but not yet implemented in the alpha version of the simulator. The code is currently being developed to work in the next version of PSS IV. Future results could reveal the trade-off between capital-intensive pipelines and operational-cost-intensive ships and suggest the optimal supply chain for CO_2 transport from the source to the CO_2-EOR projects.

The results show near-realistic insights in the costs and benefits for offshore CO_2-EOR on the North Sea using real options. The model can be further developed to be used in the offshore European context as well as other regions. As already stressed by US Department of Energy (2014), there is a potential for offshore CO_2-EOR in the Gulf of Mexico, Abu Dhabi, Vietnam and Malaysia. The potential is high, but there is also high uncertainty because of lack of information. This simulator can be used to realistically assess the potential for CO_2-EOR in these regions.

12 Conclusion

Traditional net present value based investment schemes neglect the geological uncertainties of the reservoirs for offshore CO_2-EOR. This thesis proposed a valuation method for offshore CO_2-EOR projects by using a real option decision scheme that includes uncertainties for multiple fields. The main research question was to assess the impact of including uncertainties and flexibility on the value of offshore CO_2-enhanced oil recovery projects compared to traditional investment decisions.

The relevant parameters that were included are related to geology, techno-economics and scenarios. Geological parameters describe the performance of the oil fields when primary production and CO_2-EOR are operational, such as annual oil production, CO_2 injection rates and EOR ratio. Techno-economic parameters are related to the costs for capturing a certain quantity of CO_2 and transport optimizing. The oil market price and CO_2 market price are scenario parameters. The dynamics of primary oil production and CO_2-EOR are modeled using lognormal curves in a techno-economic simulator. Seven generic CO_2-EOR projects clustered in the North Sea were valuated and investment decisions were simulated.

The alpha version of PSS IV provided a realistic assessment of potential CO_2-EOR projects in the North Sea. All simulated primary oil production projects were retrofitted to CO_2-EOR, but when and where EOR is activated is strongly influenced by the stochastic oil market price, as well as the CO_2-EOR field performance. Well-founded investment decisions were simulated based on the real option values of the alternatives to either stop primary production or retrofit to CO_2-EOR. Realistic forecasts were made for potential CO_2-EOR projects in which geological uncertainty of CO_2-EOR field performance is taken into account. All primary production projects were retrofitted to CO_2-EOR operations when uncertainties and flexibility were included in the simulations. By comparing the simulation outputs with the uncertainty ranges of CO_2-EOR reservoir modeling, it is shown that this new methodology produces reliable results.

The CO_2-EOR performance and the oil market price are the most sensitive parameters for the valuation of CO_2-EOR projects. The CO_2-EOR performance is determined by the expected amount of oil that can be produced. Economies of scale are visible in the pipeline investments for transporting the CO_2.

The main benefits of the real option approach in comparison with traditional investment decisions is that it is possible to make realistic assessments of offshore CO_2-EOR projects including the complete uncertainty range of the geological, techno-economic and scenario parameters. It is expected that realistic geological uncertainty and project risk can have an important influence on overall project costs, project planning and the timing.

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