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## The role of CO<sub>2</sub>-EOR for the development of a CCTS infrastructure in the North Sea region: A techno-economic model and application

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#### IMPRESSUM

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# The Role of CO<sub>2</sub>-EOR for the Development of a CCTS Infrastructure in the North Sea Region

## *A Techno-Economic Model and Application*

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### Abstract

Scenarios of future energy systems attribute an important role to Carbon Capture, Transport, and Storage (CCTS) in achieving emission reductions. Using captured CO<sub>2</sub> for enhanced oil recovery (CO<sub>2</sub>-EOR) can improve the economics of the technology. This paper examines the potential for CO<sub>2</sub>-EOR in the North Sea region. UK oil fields are found to account for 47% of the estimated total additional recovery potential of 3739 Mbbl (1234 MtCO<sub>2</sub> of storage potential). Danish and Norwegian fields add 28% and 25%, respectively. Based on a comprehensive dataset, the paper develops a unique techno-economic market equilibrium model of CO<sub>2</sub> supply from emission sources and CO<sub>2</sub> demand from CO<sub>2</sub>-EOR to assess implications for a future CCTS infrastructure. The demand for “fresh” CO<sub>2</sub> for CO<sub>2</sub>-EOR operation is represented by an exponential storage cost function. In all scenarios of varying CO<sub>2</sub> and crude oil price paths the assumed CO<sub>2</sub>-EOR potential is fully exploited. CO<sub>2</sub>-EOR does add value to CCTS operations but the potential is very limited and does not automatically induce long term CCTS activity. If CO<sub>2</sub> prices stay low, little further use of CCTS can be expected after 2035.

### Keywords:

CO<sub>2</sub>-EOR; CCTS; complementarity modeling; CO<sub>2</sub> transport

### JEL Code:

C61; L71; O33

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# 1 Introduction

Since the IEA “Blue Map Scenario” announced that achieving ambitious CO<sub>2</sub> reduction goals without Carbon Capture, Transport and Storage (CCTS) would result in severely higher abatement costs, the technology has become one of the cornerstones of international climate change mitigation policies. Following the scenario, CCTS contributes 19% to the global least cost emission reduction pathway which is a higher share than for renewables and 3 times higher than the share of nuclear power (cf. OECD/IEA 2010). In its more recent study “Energy Technology Perspectives 2012”, the IEA again underlines the importance of CCTS with an overall 20% contribution to achieving emission reduction goals and a 40% cost increase in absence of the technology (IEA 2012a).

For OECD Europe OECD/IEA (2010) and IEA (2012a) forecast an installed capture capacity of 140 GW and 77 GW in the power sector, respectively, a total of 990 MtCO<sub>2</sub> and 550 MtCO<sub>2</sub> stored annually, and a CO<sub>2</sub> pipeline network of over 27,000 km in 2050. Other, more detailed models also confirm the role of CCTS for achieving European decarbonization targets and forecast an intensive use of the technology by 2050. Estimates of the European Commission’s Joint Research Centre predict over 20,000 km of CO<sub>2</sub> pipelines to be in place by 2050 (Morbee, Serpa, and Tzimas 2010). The PRIMES model used to assess the European Commission’s “Energy Roadmap 2050” forecasts an average 108 GW of capture capacity to be installed in the power generation sector by 2050 and a total annual storage of 347 MtCO<sub>2</sub> in Europe in 2050 (EC 2011b) (cf. Table 1).

Technology deployment	Source Model	Year	
		2020	2050
Power Generation in GW	OECD/IEA <sup>a</sup>	5.5	140
	IEA <sup>b</sup>	4.9	77
	PRIMES <sup>c</sup>	3	108
Storage in Mt CO <sub>2</sub> per year	OECD/IEA <sup>a</sup>	37	990
	IEA <sup>b</sup>	52	550
	JRC <sup>d</sup>	36	900
	PRIMES <sup>c</sup>	18	347
Pipeline length in km	OECD/IEA <sup>a</sup>	1400	27500
	JRC <sup>d</sup>	2005	20374

<sup>a</sup> (OECD/IEA 2010): Blue Map Scenario; values for transport infrastructure are averages of spans given in the study.

<sup>b</sup> (IEA 2012a)

<sup>c</sup> (EC 2011b): Values are averages from scenarios for Energy Roadmap for 2050

<sup>d</sup>(Morbee, Serpa, and Tzimas 2010): InfraCCS model with input data from PRIMES Baseline Scenario 2009. Model used in assessment of European CO<sub>2</sub> transport infrastructure requirements (EC 2011a).

**Table 1: Key estimates of CCTS technology deployment in 2020 and 2050.**

In its EU Energy Roadmap 2050 the European Commission furthermore acknowledges that in all scenarios except those with high share of renewable energy, CCTS contributes with a large share of 19 to 24% to the decarbonization of the energy system. The technology is also recognized as an important decarbonization option for heavy industry and as an option for negative emissions in combination with biomass. CCTS has to be commercially available for all fossil technologies by 2030 at the latest. Investments are needed in the next decade and demonstration has to start not later than 2020. At the same time the roadmap is skeptical as to whether the technology will be available at all. Public acceptance and adequate price signals via the carbon price are seen as the crucial factors for the deployment of the technology (EC 2011c).

Although the estimates on the deployment of the technology have become more conservative in the course of the last few years, CCTS remains one of the core technologies in a decarbonized energy portfolio. These strong expectations are in great contrast to the current development of the technology. According to Hirschhausen et al. (2012 a) not a single CCTS project that employs the entire CCTS technology chain on a demonstration scale has yet been realized. The one project that could potentially have moved from the execution to the operation stage during the course of the year, namely the Dutch Road Project, is now planned to commence operation only in 2015 (ROAD 2012). According to Hirschhausen et al. (2012 a) there are 5 major reasons why the industry did not fulfill the great hopes put into CCTS so far:

1. There is a lack of incentives for stakeholders in fossil fuel power and equipment industry to invest into CCTS Research and Development (R&D) unilaterally: Given the currently low and uncertain CO<sub>2</sub> price as the single switching incentive, the investment into this uncertain technology would endanger established revenue streams from conventional fossil fuel generation by threatening to establish CCTS as industry-wide standard. Therefore joint R&D initiatives are formed but no breakthroughs are being achieved.<sup>1</sup>
2. There was a wrong choice of technology: Instead of concentrating on most developed post-combustion capture technology, new and uncertain pre-combustion and oxy-fuel technologies were promoted equally thereby splitting individual funds.
3. There is a discrepancy between model results and real world development due to overly optimistic cost reduction and learning curves assumed in the models for the CCTS technology and the neglect of transport and storage as important cost drivers.
4. In the past there was a focus on the wrong industry: instead of concentrating funds and R&D on the power generation sector, heavy industry should have been granted more attention. Iron and steel, as well as cement and klinker production are responsible for a great share of anthropogenic CO<sub>2</sub> emissions and have potentially lower capturing costs and lower technology barriers for CO<sub>2</sub> capture.
5. There was a neglect of costs and complexity related to regulatory issues of CO<sub>2</sub> transport and regulatory and technological issues of CO<sub>2</sub> storage.

The impact of legal concerns on trans-boundary CO<sub>2</sub> shipment and the lack of public acceptance and “not in my backyard” (NIMBY) attitudes were underestimated. Prolonging negotiations and complicated environmental assessments postpones the implementation of planned demonstration projects.

Some of the issues raised by Hirschhausen et al. (2012 a) are also addressed by some of the more recent analyses, in particular the inclusion of heavy industries (cf. IEA and UNIDO 2011) and an intensive analysis of costs and complexities related to CO<sub>2</sub> transport and storage (cf. ZEP 2011; IEA GHG and ZEP 2011). At the same time, the first and most important argument of Hirschhausen et al. on the lack of financial incentives has not seen any substantial evolution. The central dilemma with CO<sub>2</sub> is that after heavily investing into capturing it from combustion processes, it remains a useless waste product that needs to be disposed which is again associated with costs. This can change if the captured CO<sub>2</sub> is used as a value-adding input for another process. All projects listed in the “operate” or “execute” stage by the Global CCS Institute (2011) are gas processing or industrial processes with favorable capture conditions (ethanol and fertilizer production). They all share a common component of low capturing costs or even generation of additional revenue streams. Global CCS Institute (2011) and Parsons Brinckerhoff (2011) examined existing CO<sub>2</sub>-reuse options and assessed their market

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<sup>1</sup> Such a situation was also observed with other pollution control innovations in the past (cf. Hackett 1995) .

readiness and potential contribution as a consumer of captured CO<sub>2</sub>. The next paragraph summarizes findings from the latter study on the potential of CO<sub>2</sub> reuse:

CO<sub>2</sub>-EOR and urea yield boosting are two widely used commercially available technologies which require CO<sub>2</sub> as an input. The Bauxite residue (red mud) carbonation technology is in initial commercial operation while facilities using CO<sub>2</sub> in methanol production are being constructed on a commercial scale at the moment. The application of both technologies is very site specific and requires favorable local conditions. The use of CO<sub>2</sub> in enhanced coal bed methane recovery, as a working fluid in enhanced geothermal systems, as feedstock in polymer processing, and for algae cultivation are all technologies that need to be further developed and proven in real world pilot or demonstration scale applications. The global market for CO<sub>2</sub> reuse for all technologies currently has a volume of approximately 80 Mt per year, with a predominant use of 50 Mt of CO<sub>2</sub> for EOR in the U.S. and Canada. 80% of the CO<sub>2</sub> is currently supplied from natural CO<sub>2</sub> sources at a price in the order of US\$15-19 per ton. In total, anthropogenic CO<sub>2</sub> emissions can only be offset to a few percent by current and potential future demand for CO<sub>2</sub> reuse. Although reuse has very limited total potential in impacting global CO<sub>2</sub> abatement, it can generate modest revenues for near term CCTS projects.

IEA and UNIDO (2011) give a similar assessment of the role of CO<sub>2</sub>-EOR for the development of the CCTS technology appraising it as an important way to add value to a CCTS operation. IEA (2012a) acknowledges that CO<sub>2</sub>-EOR not only offers a way to partly offset the costs of demonstrating CO<sub>2</sub> capture but also to drive the evolution of CO<sub>2</sub> transportation infrastructure and incorporates opportunities for learning about certain aspects of CO<sub>2</sub> storage in some regions. Several studies have looked into the economics of CO<sub>2</sub>-EOR on a regional and national scale: e.g. the application of the technology in the UK Central North Sea/Outer Moray Firth region (Scottish Centre for Carbon Storage 2009; Kemp and Kasim 2012) and the Norwegian continental shelf (Klokk et al. 2010). They have found substantial potential for the combination of the two technologies and associated benefits.

Indicative scenarios of varying the CO<sub>2</sub> certificate price and crude oil price path examined in this study point out that despite exponential storage costs, investments in CO<sub>2</sub>-EOR operations in mature oil fields in the North Sea Region could be highly economically beneficial and the limited potential is fully exploited in all scenarios. Variations of the crude oil price influence both the supply pattern of CO<sub>2</sub> for CO<sub>2</sub>-EOR operations and later CCTS deployment. While a low CO<sub>2</sub> certificate price of 52€ per tCO<sub>2</sub> in 2050 barely triggers any long term CCTS utilization in any industry, a certificate price of 183€ per tCO<sub>2</sub> in 2050 leads to a full deployment in all emission intensive industries.

This work is designed to yield insights into the role of CO<sub>2</sub>-EOR as a driver for the development of a future CCTS infrastructure. To do so it provides two contributions to the current academic debate:

1. Based on an intensive technology and literature review, the study presents a comprehensive estimate of the CO<sub>2</sub>-EOR potential of mature oil fields in the North Sea Region and associated costs, on a site-by-site basis.
2. The study develops an equilibrium model of CO<sub>2</sub> demand from CO<sub>2</sub>-EOR operations and CO<sub>2</sub> supply from facilities investing in carbon capture. The Carbon Capture, Transport, Storage and Enhanced Recovery (CCTSAER) model gives two categories of valuable results: On the one hand the model set-up allows for a detailed analysis of capture and storage activities on a site-by-site basis. CO<sub>2</sub> streams can be examined in great detail allowing for the identification of transport routes and cross-border shipment volumes. Associated capital costs and variable expenditures of utilizing the technologies can be tracked on a disaggregated level. On the other hand, the model enables the analysis of the interactions of the individual entities (traders, CO<sub>2</sub> emitters, CO<sub>2</sub> transmission network operators, and CO<sub>2</sub>-EOR and other storage operators) in a market equilibrium setting. It explicitly calculates market clearing prices of CO<sub>2</sub>



at the gate of the capturing facility and CO<sub>2</sub> prices perceived by CO<sub>2</sub> storage operators including the transportation fees.

The remaining document is organized as follows: In Section 2 fundamentals of the CO<sub>2</sub>-EOR technology are explained and the potential for CO<sub>2</sub>-EOR in the North Sea Region is estimated. Section 3 presents a literature review of existing CCTS infrastructure models and other related complementarity models. Building up on this review the CCTSAER is introduced and input data is presented. Indicative scenarios are introduced, analyzed and interpreted in Section 4. Finally Section 5 gives conclusions, followed by ideas on further research.

## **2 Fundamentals of CO<sub>2</sub>-EOR and its potential in the North Sea Region**

To be able to assess the potential implication of the use of CO<sub>2</sub>-EOR for the development of CCTS it is crucial to understand the mechanisms of the technology, to identify the critical prerequisites for its application, and to examine its potential in both additional revenue and CO<sub>2</sub> storage on a site-specific scale.

### **2.1 Mechanisms of CO<sub>2</sub>-EOR**

CO<sub>2</sub>-EOR is a technology which is applied in crude oil production since the 1980s in the U.S. Once primary and secondary recovery fails to deliver economic production rates, tertiary or enhanced recovery can be employed to further extend the economic lifetime of an oil field. To do so, substances changing the properties of crude oil flow and those of the rock-fluid interactions in the reservoir are injected into the reservoir. One of these substances capable of favorably altering the physical properties of the crude oil is CO<sub>2</sub>.

In general there are two fundamentally different principles how CO<sub>2</sub> can be applied in crude oil production to increase or prolong the output. The applicability of the respective processes depends on the thermodynamic conditions present in the reservoir.

#### **2.1.1 Miscible and immiscible displacement using CO<sub>2</sub>**

For miscible displacement the CO<sub>2</sub> needs to be in supercritical phase under the pressure level at reservoir depth. The minimum value that satisfies these conditions is referred to as the Minimum Miscible Pressure (MMP) (Godec et al. 2011). In this state the CO<sub>2</sub> is fully miscible with the crude oil. The blend reduces the capillary forces of the crude oil that otherwise hinder the fluid to flow through the pores of the reservoir by reducing the interfacial tension between the oil and the reservoir rock. Secondly, the mixing expands the volume of the oil (oil swelling) and the subsequent reduction of its viscosity. Moreover, the development of favorable complex phase changes in the oil increase its fluidity. Since the well pattern can remain unchanged for the application of this technology to conventional oil production, the time window for implementation opens a few years before the end of the conventional life time and closes at about the cease of secondary recovery. Most efficient is the combination of sequential water and CO<sub>2</sub> injection, a method called water altering gas (WAG). It combines the positive effects of blending crude oil and CO<sub>2</sub> and the sweeping effect of the water (Tzimas et al. 2005).

In cases where MMP is not given, CO<sub>2</sub> can still be used to enhance oil recovery applying immiscible displacement methods. Although the CO<sub>2</sub> is not fully miscible in this case, it still induces some swelling of the oil and hence reduces its viscosity. Secondly, and more important for this application method, the CO<sub>2</sub> is used to displace the oil just like water in secondary recovery. The method applied is called gravity stable gas injection (GSGI). In this application the CO<sub>2</sub> is slowly injected just at the crest of the

reservoir to create an artificial gas cap that forces the oil downwards and to the rim of the reservoir where the production wells are located. Immiscible displacement projects require long injection periods and are typically applied to a reservoir as a whole. Substantial amounts of CO<sub>2</sub> need to be injected through newly constructed wells, while additional oil production is very slow and does not start before ten and more years after first injection. The presence of water e.g. from previous water injection reduces the effectiveness of this method hindering the downward flow of the oil. Although immiscible displacement projects can potentially store higher amounts of CO<sub>2</sub> than miscible operations, due to unfavorable economics described before they have found little application so far (Tzimas et al. 2005).

Due to broad experience, more favorable economics and wide applicability, miscible displacement is considered as the employed CO<sub>2</sub>-EOR method for the assessment made in this paper.

### 2.1.2 Theoretical recovery and storage potential of CO<sub>2</sub>-EOR

In general the effectiveness of a CO<sub>2</sub>-EOR operation depends on the geological and thermodynamic characteristics of the reservoir and the characteristics of the crude oil in place including: temperature, pressure, height, angle, oil gravity and heterogeneity (ARI and Mezler Consulting 2010). Table 3 displays selection criteria for CO<sub>2</sub>-EOR operations from various studies. One key determinate is the MMP which ensures that the CO<sub>2</sub> is supercritical and therefore fully miscible under reservoir conditions. In a first order approach it can be determined using the depth and the temperature of the reservoir as done by Godec et al. (2011). Another traceable characteristic is the specific oil gravity (°API) which is a measure for the specific density of the crude oil in place. For optimal operation it should be in the same range as specific density of supercritical CO<sub>2</sub> to ensure optimal miscibility and to prevent early CO<sub>2</sub> breakthrough (Tzimas et al. 2005). Residual oil saturation before CO<sub>2</sub>-EOR is applied also crucially influences the profitability of operation. While reservoir characteristics like homogeneity and porosity are very site-specific and less easily traceable they are decisive for the economics of an operation (Meyer 2007).

Source	Incremental recovery factor from CO <sub>2</sub> -EOR application in % OOIP	Conditions reducing CO <sub>2</sub> -EOR potential in European North Sea
Godec et al. (2011)	11 (average for Europe)	
Scottish Center for Carbon Storage(2009)	5-15	Low recovery factor due to: <ul style="list-style-type: none"> <li>• lower well density</li> <li>• higher water flood recovery</li> </ul>
Lake and Walsh (2008)	Present own model for individual calculation based on various input parameters	
Tzimas et al. (2005)	4-12	Low recovery factor due to: <ul style="list-style-type: none"> <li>• unfavorable reservoir conditions</li> <li>• lower oil saturation after efficient water injection</li> <li>• difficult pressure management due to more loose well spacing</li> </ul>
Mathiassen (2003)	4-8	

**Table 2: Estimates of incremental recovery factors from CO<sub>2</sub>-EOR**

With different field characteristics incremental oil recovery from CO<sub>2</sub>-EOR differs significantly. Some studies give a range of 7-23% (e.g. Meyer 2007 for an average U.S. operation) while others are more conservative indicating 4-12% additional recovery (e.g. Tzimas et al. 2005). Table 2 gives an overview of incremental recovery factors assumed in different studies. It is worth mentioning that studies that

focus on European CO<sub>2</sub>-EOR potential acknowledge unfavorable condition in the North Sea region due to lower well density, substantial past water flooding and unfavorable reservoir characteristics.

Assessing the net efficiency of CO<sub>2</sub> utilization, i.e. the ratio of CO<sub>2</sub> injected to additional barrel of crude oil recovered, is a two dimensional problem. On the one axis recovery is again site-specific and varies significantly during the course of the CO<sub>2</sub>-EOR operation. Figure 1 depicts the ratio of CO<sub>2</sub> injected to additional barrel produced and also the ratio between purchased and recycled CO<sub>2</sub> used for reinjection. There is a gap of one to three years between start of injection and first incremental barrel produced (Jakobsen et al. 2005). Additional oil production peaks quite rapidly and then slowly ebbs out. Initially, fresh CO<sub>2</sub> is injected into the reservoir. After the point of CO<sub>2</sub> breakthrough the requirement for fresh CO<sub>2</sub> rapidly decreases and is replaced by recycled CO<sub>2</sub> ascending with the crude oil.

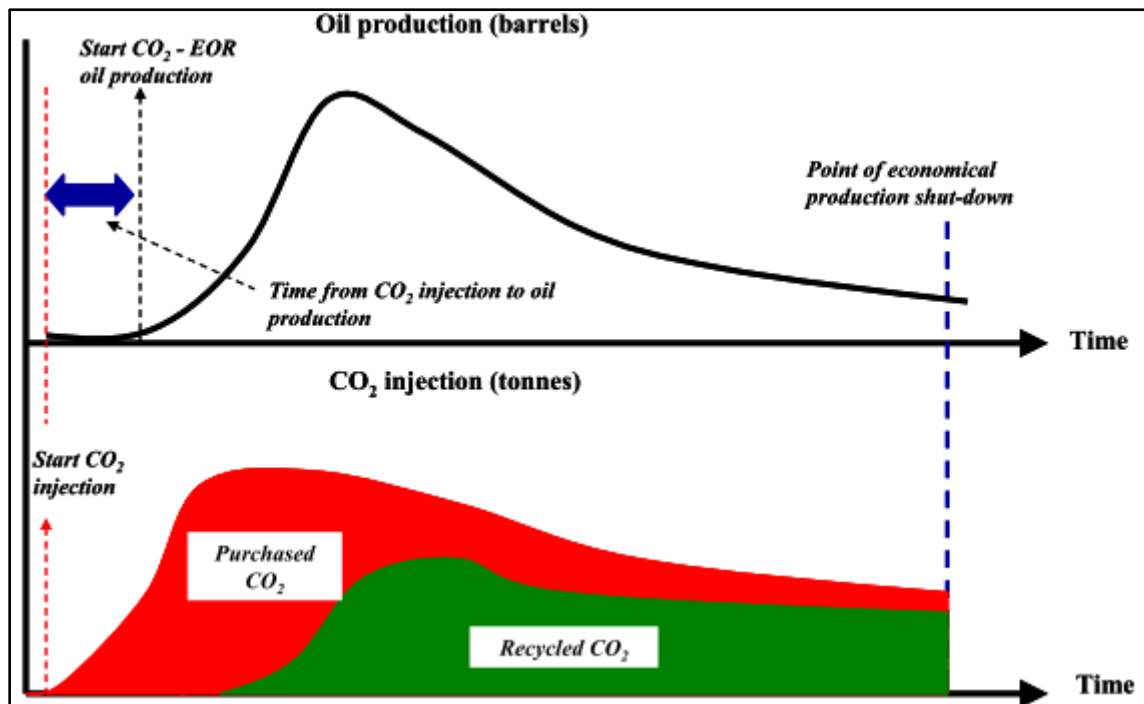
Source	Scope of Study	Selection criteria
Godec et al. (2011)	World oil basins	Oil gravity 17.5-50° API Reservoir Depth >915m (3000ft) and temperature <sup>2</sup>
Scottish Centre for Carbon Capture (2009)	Central North Sea/Outer Moray Firth region	high level desk-top review of all oil fields with an estimated CO <sub>2</sub> storage capacity of >50 Mt
Lake and Walsh (2008)	U.S. + Canada	Summary of screening criteria from various authors
Gozalpour et al. (2005)	North Sea	Summary of screening criteria from various authors
Tzimas et al. (2005)	North Sea	Oil gravity >35° API (<850 kg/m <sup>3</sup> ) Oil saturation after water flooding >35-40% Reservoir pressure > MMP Permeability > 100 mD. Homogeneity, good connectivity, low vertical heterogeneity oil viscosity 1-2 cp
Mathiassen (2003) following Bachu (2001)	Norway	Oil gravity < 900 kg/m <sup>3</sup> Oil saturation >25 % Reservoir pressure > 0.9 MMP Porosity >15 % Permeability >1 md Acceptable heterogeneity No gas cap Previous or planned water, gas or WAG flooding

**Table 3: Selection criteria of oil fields suitable for CO<sub>2</sub>-EOR.**

On the other axis, efficiency is governed by the overall objective pursued during the operation. According to Leach, Mason and Veld (2011) there is a significant trade-off between optimal process design for maximizing revenue streams from oil production only, compared to a case where CO<sub>2</sub> storage also adds value to an operation when a carbon policy is in place. With CO<sub>2</sub> supply being one of the major variable cost components, current CO<sub>2</sub>-EOR projects are designed to maximize additional recovery while minimizing the amount of CO<sub>2</sub> purchased. In the future, the ratio between water and CO<sub>2</sub> injected into the reservoir can be optimized to maximize the revenue taking both objectives into

<sup>2</sup> For a first order potential estimation MMP and data on reservoir depth and temperature is redundant information. The latter are used to estimate MMP in this and other studies.

account. While current operations on average inject 0.33 tCO<sub>2</sub> per incremental barrel of crude oil, values of 0.52 to 0.64 tCO<sub>2</sub> per barrel can be realized when employing a pure CO<sub>2</sub> stream (ARI and Mezler Consulting 2010).



**Figure 1: production profiles for CO<sub>2</sub>-injection and oil production in tertiary production.**

Source: Jacobson et al. (2005).

### 2.1.3 Is CO<sub>2</sub>-EOR a CO<sub>2</sub> abatement technology?

The source of the CO<sub>2</sub> and constant monitoring during and after the operation are crucial for the recognition of CO<sub>2</sub>-EOR as a CO<sub>2</sub> abatement technology. To be eligible as an abatement technology the CO<sub>2</sub> must come from an anthropogenic source and must have been orderly released into the atmosphere in the absence of the technology (Global CCS Institute 2011). Permanent storage can only be credited if a monitoring scheme is in place that includes baseline monitoring and demonstrates and measures effective storage. The latter prerequisite is a technical issue and can be addressed using technology available and developed for other CO<sub>2</sub> storage technologies. However, the question of additionality is very sensitive to the choice of system boundaries. There is an ongoing debate in the literature on whether to ascribe emissions generated by the combustion of the additionally recovered oil towards the life-cycle emissions of the technology. On the one hand, there are arguments that world oil production is determined by world demand and therefore the incremental oil produced from the CO<sub>2</sub>-EOR project otherwise would have been supplied from other sources that do not store CO<sub>2</sub> (Faltinson and Gunter 2010). On the other hand, crediting of CCTS for Clean Development Mechanism (CDM) Certified Emission Reductions (CER) certificates is likely to be balanced for CO<sub>2</sub> transferred outside of the project boundaries (McCormick 2012). At the same time, there seems to be no conflict between integrated CO<sub>2</sub>-EOR and CCTS projects and the EU ETS scheme. Although leakage of emissions into other sectors not regulated under the EU ETS is acknowledged as an issue that should be addressed, at the moment a regulated facility only has to hold certificates for emissions directly attributable to its operation (BMU 2008).

If emissions originating from CO<sub>2</sub>-EOR operation are to be included into the assessment of the technologies role for CCTS then its carbon footprint needs to be evaluated. ARI and Mezler (2010)

conducted a life cycle emissions analysis including the stages of operation, transport, refining, and consumption. They calculated life cycle emissions of 0.47 tCO<sub>2</sub> per incremental barrel produced (0.4 tCO<sub>2</sub> originate from combustion, while 0.03 tCO<sub>2</sub> come from refining and 0.04 tCO<sub>2</sub> from CO<sub>2</sub>-EOR operation). Hertwich et al. (2008) calculated 0.048 tCO<sub>2</sub> per incremental barrel to account for additional emissions from processes associated with EOR. Assuming current common practice CO<sub>2</sub> utilization rates of 0.33 tCO<sub>2</sub> per incremental barrel of oil, the storage of one ton of CO<sub>2</sub> would induce emissions of 1.42 tCO<sub>2</sub>. It is worth mentioning that both studies do not take into account emissions from construction of new platforms and well drilling which both might be necessary for CO<sub>2</sub>-EOR operation and which would further increase life cycle emissions. Therefore, under current production practices CO<sub>2</sub>-EOR cannot be considered a green technology.

The eligibility of CO<sub>2</sub>-EOR operations for offsetting emissions from large CO<sub>2</sub> emission sources under the EU ETS scheme is a crucial assumption for the assessment of its role for the development of a CCTS infrastructure, and is regarded as given for the following analysis, despite the debate mentioned above.

## **2.2 Assessing the potential of CO<sub>2</sub>-EOR resources in the North Sea**

The analysis of the role of CO<sub>2</sub>-EOR for the development of a CCTS infrastructure requires a comprehensive estimation of the potential for CO<sub>2</sub>-EOR in the North Sea region. This section presents a detailed database on location, estimated storage capacity, and incremental reserves of CO<sub>2</sub>-EOR fields in the North Sea Region. The methodology is based on current literature and own assumptions as described below.

### **2.2.1 Literature review on CO<sub>2</sub>-EOR potential in the North Sea Region**

An intensive literature review has been performed to compile a consistent database of CO<sub>2</sub>-EOR potentials in the North Sea region. Lake and Walsh (2008) and Gozalpour et al. (2005) have assembled a compilation of screening criteria from oil fields suitable for CO<sub>2</sub>-EOR injection. Godec et al. (2011) present a basin based estimate of the world CO<sub>2</sub>-EOR potential taking into account reservoir depth, API gravity and respective OOIP. Estimates for two European basins indicate a potential of 4.7 GtCO<sub>2</sub>. Tzimas et al. (2005) perform a screening of fields in the North Sea region based on various screening criteria and detect 59 candidate fields with potential total storage of 870-1958 MtCO<sub>2</sub>. For the UK, a case study of a possible CO<sub>2</sub> infrastructure in Scotland and the Scottish North Sea has identified 14 candidate oil fields in a high level desk-top review of all oil fields with an estimated CO<sub>2</sub> storage capacity of >50 Mt (Scottish Centre for Carbon Storage 2009). The estimated CO<sub>2</sub> storage potential amounts to 990 MtCO<sub>2</sub><sup>3</sup>. For the Norwegian North Sea oil fields Mathiassen (2003) presents a detailed analysis of CO<sub>2</sub>-EOR potential based on MMP, oil gravity, viscosity, reservoir permeability and other reservoir characteristics and estimates the total storage potential to be in the range of 499 to 666 MtCO<sub>2</sub>. For the Danish North Sea region no estimates on the potential could be found. However, the Danish Energy Agency recognizes that CO<sub>2</sub>-EOR will be the main driver to increase the currently very low oil recovery factor by up to 5% (Søndergaard and Danmark. Energistyrelsen 2012). In order to create a consistent estimate for the entire North Sea region own estimates of additional oil recovery and CO<sub>2</sub> storage potential from CO<sub>2</sub>-EOR were generated.

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<sup>3</sup> Figure based on a CO<sub>2</sub> utilization ratio of 0.33 tCO<sub>2</sub>/bbl.

## 2.2.2 Own estimate of CO<sub>2</sub>-EOR Potential in the North Sea Region

Data availability diverges significantly between the different countries of the North Sea Region. Therefore, different approaches have been chosen for the individual countries. CO<sub>2</sub> injection potentials are considered as the net amount of CO<sub>2</sub> that can be stored during the CO<sub>2</sub>-EOR process and includes a constant recycling ratio of 40% following Gozalpour et al. (2005).

### UK

The 240 on- and offshore oil fields of the UK were screened based on their OOIP and API gravity. Data was taken from Data by Design (2012) and DECC (2012). As only figures on recoverable reserves originally in place were available, a theoretical recovery factor was calculated based on the API gravity to arrive at an estimate of the OOIP (Qing Sun, Sloan, and C&C Reservoirs 2003). Reservoirs with OOIP of less than 100 Mbbbl or an API gravity of less than 35° were excluded due to uneconomically small potential and unfavorable conditions for CO<sub>2</sub>-EOR. Additional recovery potential was calculated based on a conservative estimate of 4% OOIP<sup>4</sup>. For the calculation of the CO<sub>2</sub> injection potential a utilization ratio of 0.33 tCO<sub>2</sub> per bbl<sup>4</sup> was employed, assuming an injection scheme optimized on CO<sub>2</sub> utilization which is most common in current operations. Geo-coordinates were retrieved from DECC (2012). Figure 2 shows the 54 candidate fields with an estimated net injection potential ranging between 2 and 89 MtCO<sub>2</sub> (Forties field). Total UK potential sums up to 572 MtCO<sub>2</sub> which corresponds to 1733 Mbbbl additional oil recovery potential.

### Norway

Mathiassen (2003) presents a comprehensive evaluation of the Norwegian CO<sub>2</sub>-EOR in the North Sea Region. The analysis covered the most important selection criteria and performed a Monte Carlo simulation to estimate additional recovery rates. Information provided was used to arrive at an estimate for the CO<sub>2</sub> injection potential of the respective oil fields using the same CO<sub>2</sub> utilization ratio as for the UK. Geo-coordinates were retrieved from Norwegian Petroleum Directorate (2012). Figure 2 shows the seven Norwegian candidate fields with an estimated net injection potential ranging between 4 and 130 MtCO<sub>2</sub> (Ekofisk field). Total storage potential in Norwegian oil fields in the North Sea add up to 314 MtCO<sub>2</sub> which corresponds to an additional oil recovery potential of 951 Mbbbl.

### Denmark

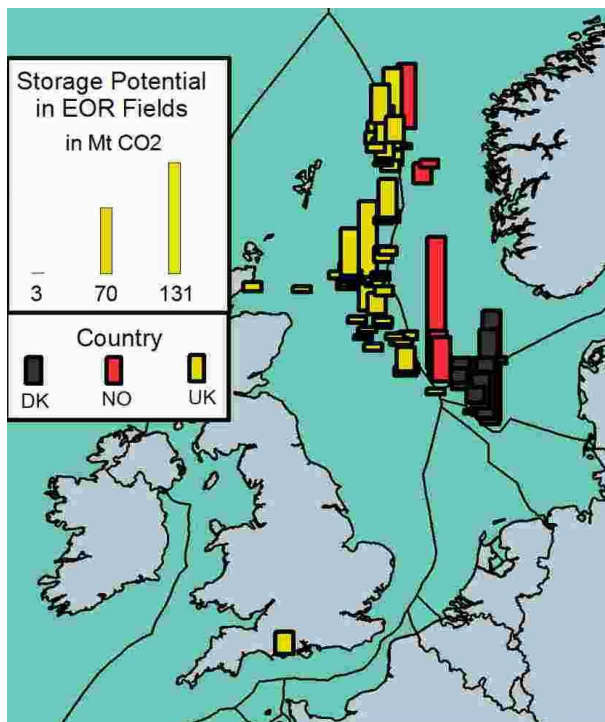
Assessments of the Danish CO<sub>2</sub>-EOR potential were made based on estimates of OOIP for the respective oil fields. Figures on production history and estimated reserves were charged against a currently very low recovery factor of 26.3% (Søndergaard and Danmark. Energistyrelsen 2012). The additional CO<sub>2</sub>-EOR recovery was set to 8% to account for the favorable conditions that were found in the Danish chalk formations (cf. Olsen (2011)). The same CO<sub>2</sub> utilization ratio as for the UK was employed for the Danish oil fields. Figure 2 shows the 14 Danish candidate fields with an estimated net injection potential ranging between 3 and 88 MtCO<sub>2</sub> (Dan field). Total storage potential in Danish oil fields sum up to 348 MtCO<sub>2</sub> which corresponds to an additional oil recovery potential of 1054 Mbbbl.

Other riparian countries of the North Sea do not have substantial oil resources and are therefore not included in the analysis.

Figure 2 shows the location and the respective CO<sub>2</sub> storage potential for mature oil fields in the Danish, UK and Norwegian North Sea while Table 4 summarizes the estimated CO<sub>2</sub>-EOR potential for the respective country.

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<sup>4</sup> See Section 2.1.2 for more details.



**Figure 2: CO<sub>2</sub> injection potential in the North Sea Region based on 4% additional recovery and 0.33 tCO<sub>2</sub> per bbl utilization rate.**

Country (# of potential fields)	Range of field size in MtCO <sub>2</sub> (largest field)	Estimated potential in MtCO <sub>2</sub> (Mbbbl)
UK (54)	2-89 (Forties)	572 (1733)
Norway (7)	4-130 (Ekofisk)	314 (951)
Denmark (13)	3-88 (Dan)	348 (1054)

**Table 4: Estimates of additional recovery and net storage potential from CO<sub>2</sub>-EOR in the North Sea Region by country**

### 3 The Carbon Capture, Transport, Storage and Enhanced Oil Recovery Model (CCTSAER)

#### 3.1 Literature Overview

Current state of the art CCTS infrastructure simulation models are set up as mixed integer problems (MIP) where one cost minimizing entity decides on which facility to equip with capture, where to explore and develop a CO<sub>2</sub> storage site and on routes and capacities for potential transport connections. Recently, much effort has been put in adequately representing potential economies of scale in the transport infrastructure. Mendelevitich et al. (2010) present a scalable mixed integer, multi-period, cost minimizing CCTS network model for Europe, called CCTS-Mod. The model incorporates endogenous decisions about carbon capture, pipeline and storage investments, and capture, flow and injection quantities based on given costs, CO<sub>2</sub> prices, storage capacities and point source emissions. Based on perfect foresight for the development of technology and CO<sub>2</sub> certificate costs, the model determines a cost minimizing strategy between purchasing CO<sub>2</sub> -certificates and abating the CO<sub>2</sub> through investments into a CCTS-chain. The model is applied to examine the potential CCTS infrastructure in Europe given different CO<sub>2</sub> price paths and altering assumptions on capacity and availability of CO<sub>2</sub> storage sites. An update on input data and a refined scenario analysis is given in

Herold et al. (2011). The model is based on a structure presented by Middleton and Bielicki (2009) for their SimCCS model. Investment decisions in each step of the CCTS technology chain are represented via binary variables and economies of scale inherent to the transport infrastructure are implemented by allowing the model to choose from a limited number of discrete pipeline capacities with concave costs per unit of capacity. In its most recent version the model also incorporates a sophisticated procedure to develop a candidate transport network. It uses information on topography, interference with other infrastructure, ownership, land-use, right of way and population density and applies network refining methods to arrive at a candidate network that connects potential CO<sub>2</sub> storage site and large CO<sub>2</sub> emission sources (Middleton, Kuby, and Bielicki 2012).

Morbee et al. (2012) take a different approach to generate the candidate network. They employ a clustering algorithm that produces clusters of CO<sub>2</sub> source and storage sites. Furthermore they use hydrological properties of the potential CO<sub>2</sub> stream rather than different pipeline diameters to represent economies of scale in the pipeline infrastructure. One of the major shortcomings of their InfraCCS model is that it requires capture CO<sub>2</sub> amounts at every network node as an endogenous input and is therefore not able to assess the deployment of a CCTS infrastructure in a comprehensive approach.

In parallel, various joint industry and research projects have tried to analyze the deployment of the CCTS technology. For example, the CASTOR project worked on developing a strategy and understanding of the feasibility of developing a large-scale CCTS infrastructure in Europe by calculating the effects of a 30% CO<sub>2</sub> emission reduction in the power generation sector through CCTS until 2050 (Wildenborg et al. 2009). After clustering and matching sinks and sources "by hand" they estimated the evolution of CO<sub>2</sub> streams and storage quantities for 12 EU member states and Norway. The CO<sub>2</sub> Europipe Project used a similar approach to establish the candidate network (Neele et al. 2011). They used the output of the PRIMES energy model as input for quantities of CO<sub>2</sub> captured per year assuming that one third of the emission reductions will be achieved through CCTS. By contrast, the Chalmers Electricity Investment model (ELIN) endogenously determines the level of capture for large scale emission sources from power generation based on investment decision for new capacity that has to satisfy an exogenous electricity demand in a cost efficient way (Kjärstad et al. 2011). For the industry sector (steel, refinery, cement) they assume capture to be mandatory once it is deployed in the power sector. Investments into transport infrastructure are calculated in the aftermath. Decisions on pipeline routing, capacities and associated transport costs are not taken into account in the initial assessment of the capture investment.

CO<sub>2</sub>-EOR as a storage option and more importantly as an option to generate additional revenue is barely included into comprehensive CCTS models. Middleton et al. (2011) performed a case study on the effects of combining CCTS for the refinery sector with CO<sub>2</sub>-EOR for the Gulf States. While the presented results include a sensitivity analysis of different assumptions on capture and storage costs and their respective implications on captured quantities, the model only shows a static view and does not include other sectors and potential development over time. Furthermore the model does not make any EOR-specific assumptions about the evolution of the CO<sub>2</sub> demand and potential dynamic changes of the storage costs. Holt et al. (2009) present an economic assessment of CO<sub>2</sub>-EOR and CO<sub>2</sub> disposal in 30 UK and 18 Norwegian oil fields and adjacent saline aquifers in the North Sea. The dynamics of CO<sub>2</sub> demand for each individual field is modeled in great detail assuming a WAG process and changing water to CO<sub>2</sub> and fresh CO<sub>2</sub> to recycled CO<sub>2</sub> ratios over time. A shortcoming of this study is the approach towards the capture step of the CCTS technology. It assumes a fixed amount of CO<sub>2</sub> delivered from UK and Continental Europe over a project life time of 40 years. Although a sensitivity analysis on the CO<sub>2</sub> price is performed the model is not capable of identifying the sources of the CO<sub>2</sub> stream. Klock et al. (2010) used a MIP formulation to set up a net present value maximizing model for the assessment of five industry CO<sub>2</sub> sources and 14 potential CO<sub>2</sub>-EOR fields in Norway.



Particular to their approach is that it considers a window of opportunity for CO<sub>2</sub>-EOR operation and penalizes late starts by reducing the respective CO<sub>2</sub> utilization efficiency for later starts of operation. Due to its limited scope, the study is not capable of analyzing European wide CCTS development.

All presented approaches share the disadvantage of assuming a central planner that organizes the deployment of the CCTS technology in a cost minimizing way. This model setting is not able to acknowledge that investment decisions are made by individual players that have different objectives. A model formulation which is capable of representing individual players' decisions is the set up as a Mixed Complementarity Problem (MCP). This setting allows to represent network equilibriums of supply and demand which are more appropriate in models where individual users share the same network (Magnanti and Wong 1984). In this case the individual companies facing carbon policies will potentially share a common CO<sub>2</sub> transport infrastructure.

The MCP formulation has been applied to a number of network industries e.g. electricity markets (Neuhoff et al. 2005) and world gas market (Egging, Holz, and Gabriel 2010). Many complementarity models make use of the explicit representation of a market clearing price as the shadow variable of market clearing conditions. For example Golombek et al. (2011) use their MCP LIBEMOD model of the European energy market to analyze the future deployment of CCTS. Investments into the technology are triggered via the shadow price of the market clearing condition for energy demand and supply. Moreover many authors use MCP formulations for markets where dominant players can influence prices by exerting market power, e.g. for Russia on gas trades towards Europe (Egging, Holz, and Gabriel 2010). Besides, MCP model formulations can handle non-linear cost functions as long as they produce a convex solution set. These can be used to represent non-linear production costs (see e.g. Abada et al. 2012) or non-linear investment costs towards the end of the economic lifetime of a resource (see e.g. Huppmann 2012).

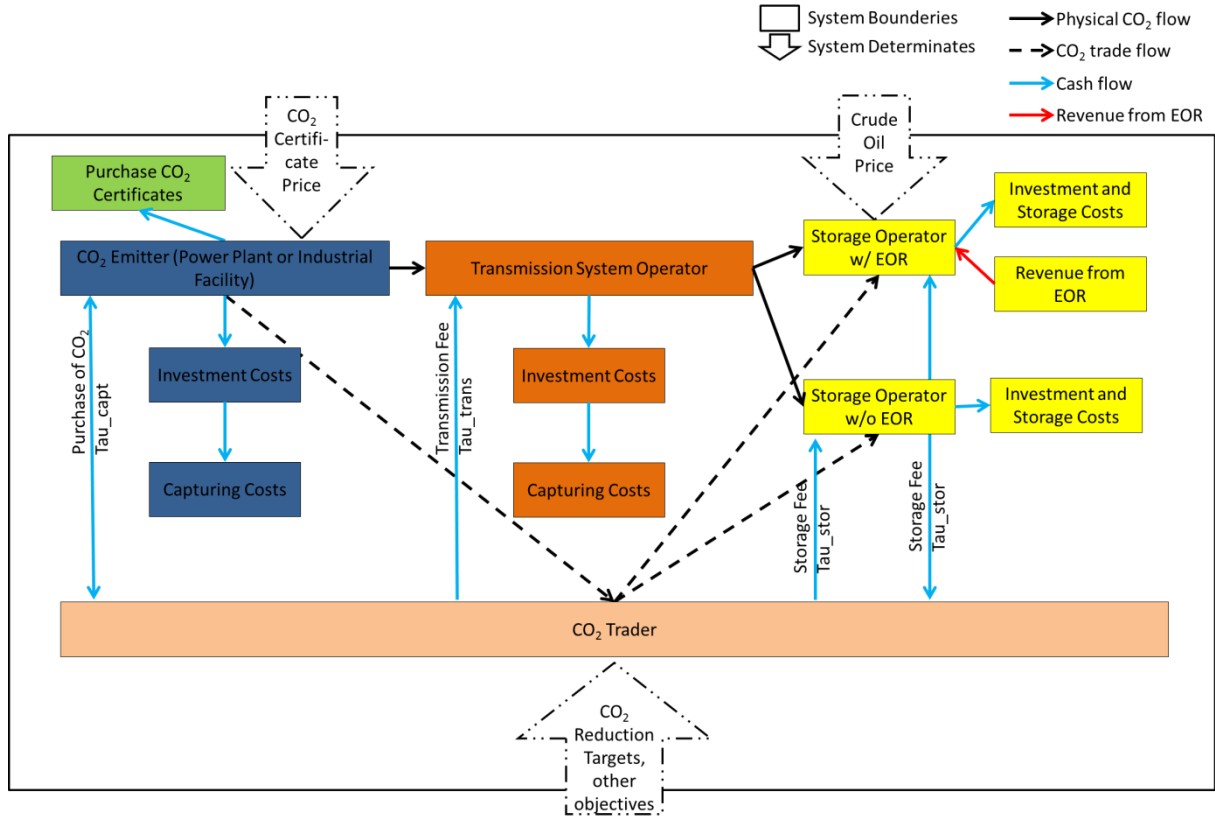
## 3.2 Model Formulation

Building up on the different concepts presented in the previous literature review the **Carbon Capture Transport, Storage And Enhanced Recovery (CCTSAER)** model is designed to simulate the potential development of a CCTS infrastructure and to assess the role CO<sub>2</sub>-EOR can play to facilitate and incentivize early deployment.

Figure 3 depicts the general set-up of the model: An individual CO<sub>2</sub> emitting facility (any emission point source included in the database, for more details see data Section 3.3.1) faces the decision whether to purchase CO<sub>2</sub> certificates that follow an exogenous price path or to invest into a capture facility and to sell its CO<sub>2</sub> to a CO<sub>2</sub> trader. A CO<sub>2</sub> trader represents a governmental entity that coordinates the CO<sub>2</sub> market and potentially prohibits or incentivizes CO<sub>2</sub> trades that are favorable for his objective. His objective may be a CO<sub>2</sub> reduction target, other environmental goals e.g. minimizing onshore storage or cross-border CO<sub>2</sub> flows, or combinations of financial and environmental objectives. The trader contracts a transmission system operator to construct and operate a CO<sub>2</sub> transportation system that connects the CO<sub>2</sub> sources to potential CO<sub>2</sub> storage sites via pipeline or ship and compensates him via a transmission fee. In the last step of the CCTS technology chain the trader sells the CO<sub>2</sub> to a storage operator. Two kinds of storage operators can be distinguished: For an operator of a CO<sub>2</sub>-EOR site the CO<sub>2</sub> is a valuable input that generates profits from selling the additionally recovered oil to the world market. For an operator of a saline aquifer or a depleted hydrocarbon field the CO<sub>2</sub> has no value, thus he is compensated via a storage fee which he receives from the CO<sub>2</sub> trader. The model represents a market equilibrium of CO<sub>2</sub> supply from CO<sub>2</sub> emitter and CO<sub>2</sub> demand from CO<sub>2</sub>-EOR operators.

Due to the model set-up, revenues and costs are shared along the CCTS and CO<sub>2</sub>-EOR value chains; i.e. revenues generated by the CO<sub>2</sub>-EOR operator from selling his additionally recovered crude oil to the world market are shared with the capture facilities via the purchase price of the CO<sub>2</sub> at the CO<sub>2</sub>-

EOR wellhead. Vice versa, incentives to invest into CCTS given by the CO<sub>2</sub> certificate price are also taken into account lowering the market-clearing price, respectively.



**Figure 3: General set-up of the CCTSAER model**

The model is set-up as a Mixed Complementarity Problem (MCP) and solved using the Karush-Kuhn-Tucker (KKT) conditions. Constraint qualifications that need to be fulfilled to ensure that the KKTs deliver an optimal and unique solution are not checked formally here. Nevertheless, the convex objective functions and linear constraints employed in the model (see below) in combination with the convex solution set of the model are a sufficient condition for the applicability of the KKTs. A detailed list of set, parameters and variables as well as the derived KKT conditions can be found in the Appendix. The model is implemented in GAMS and solved using the path solver.

### 3.2.1 CO<sub>2</sub> Emitters' Problem

Each CO<sub>2</sub> emitter  $p$  is trying to minimize his discounted expenditures induced by his CO<sub>2</sub> emissions  $co2_{p,a}$  and the consequent obligation of balancing them with CO<sub>2</sub> certificates over all model periods  $a$  (1) with  $r$  being the discount rate and  $start$  being the start year of the model. He can either purchase CO<sub>2</sub> certificates for a given certificate price  $cert_a$  or invest into a capturing facility, facing investment costs  $c_{inv\_x_{p,a}}$  and variable capture costs  $c_{p,a}$ . The latter incorporate variable costs of operating and maintaining the facility as well as an energy penalty due to the resulting efficiency decrease.  $x_{p,a}$  is the amount of CO<sub>2</sub> capture from emitter  $p$  in period  $a$ . When selling the CO<sub>2</sub> to the CO<sub>2</sub> trader the CO<sub>2</sub> emitter receives the clearing price  $\tau_{p,a}^{capt}$ . In case the CO<sub>2</sub> cannot be used as revenue generating input in an EOR operation, this price is negative meaning that the CO<sub>2</sub> emitter pays the CO<sub>2</sub> trader for managing the remaining process steps of transport and storage.

$$\min_{x, \pi_p} \pi_p = \sum_a \frac{1}{1+r}^{a-start} \cdot \left( \begin{array}{l} c_{inv\_x_{p,a}} \cdot inv\_x_{p,a} + c_{x_{p,a}} \cdot x_{p,a} \\ -\tau_{p,a}^{capt} \cdot x_{p,a} - cert_a \cdot co2_{p,a} - x_{p,a} \end{array} \right) \quad (2)$$

An emitter can start using his CO<sub>2</sub> capture facility after a construction period of 5 years which corresponds to one model period:

$$s.t. \quad x_{p,a} - \sum_{b<a} inv\_x_{p,b} \leq 0 \quad \forall p,a \quad \alpha_{p,a}^{capt} \quad (3)$$

The maximum share of CO<sub>2</sub> captured is limited by the respective capture rate  $capture\_rate_p$  (4). The remaining CO<sub>2</sub> has to be balanced with CO<sub>2</sub> certificates.

$$x_{p,a} - co2_{p,a} \cdot capture\_rate_p \leq 0 \quad \forall p,a \quad \beta_{p,a}^{capt} \quad (5)$$

In each model period the captured CO<sub>2</sub> is purchased by CO<sub>2</sub> traders:

$$x_{p,a} - \sum_t purchase_{t,p,a} = 0 \quad \forall p,a \quad \tau_{p,a}^{capt} \text{ free} \quad (6)$$

### 3.2.2 Transmission System Operators' Problem

A CO<sub>2</sub> transmissions system operator (CO<sub>2</sub>-TSO)  $o$  is a regulated entity that manages the physical flow of the CO<sub>2</sub> between individual CO<sub>2</sub> emission sources and potential storage sites. The structure of the current gas pipeline network is used to produce the layout of a potential CO<sub>2</sub> pipeline network. Remote CO<sub>2</sub> emitters are linked by ship routes to the main network (see 3.3.2 for more details). The CO<sub>2</sub>-TSO can decide to invest into transmission capacity between network nodes  $i$  and  $j$  via his decision variable  $inv\_f_{o,i,j,a}$ . Investment costs  $c\_inv\_f_{o,i,j,a}$  depend on the type of connection (feeder or trunk) and type of terrain (onshore or offshore). Variable costs  $c\_f_{o,i,j,a}$  induced from pipeline and ship operation  $f_{o,i,j,a}$  are also included in the model. The CO<sub>2</sub>-TSO's objective is to minimize his discounted expenditures from investment and operation minus revenue from transmission fee  $\tau_{o,i,j,a}^{trans}$  (7).

$$\min_{inv\_f,f} \quad \pi_o = \sum_a \frac{1}{1+r}^{a-start} \cdot \sum_{i,j} \left( c\_inv\_f_{i,j,a} \cdot inv\_f_{o,i,j,a} + c\_f_{i,j,a} \cdot f_{o,i,j,a} \right) - \tau_{o,i,j,a}^{trans} \cdot f_{o,i,j,a} \quad (8)$$

Transport capacity can only be used after a construction period of 5 years:

$$s.t. \quad f_{o,i,j,a} - \sum_{b<a} inv\_f_{o,i,j,b} \leq 0 \quad \forall o,i,j,a \quad \alpha_{o,i,j,a}^{trans} \geq 0 \quad (9)$$

In each period the physical CO<sub>2</sub> flow  $f_{o,i,j,a}$  between nodes  $i$  and  $j$  has to equal the sum of flow  $t\_flow_{t,i,j,a}$  induced by the traders.

$$\sum_t t\_flow_{t,i,j,a} - f_{o,i,j,a} = 0 \quad \forall i,j,a \quad \tau_{o,i,j,a}^{trans} \text{ free} \quad (10)$$

### 3.2.3 Storage Operators' Problem

A storage operator  $s$  minimizes his discounted expenditures from investments and operation minus revenues generated from the storage fee  $\tau_{s,a}^{stor}$  and from additionally recovered oil that can be sold for the oil price  $oilprice_a$  to the world market (11). Investment and variable costs, both depend on storage type (EOR field, depleted hydrocarbon field, saline aquifer) and storage location (onshore or offshore).

$$\min_{inv\_y,y} \pi_s = \sum_a \frac{1}{1+r} \cdot \left( \begin{array}{l} c\_inv\_y_{s,a} \cdot inv\_y_{s,a} \\ + c\_y_s \left( \sum_{b \leq a} y_{s,a}, cap\_stor_s \right) - c\_y_s \left( \sum_{b < a} y_{s,a}, cap\_stor_s \right) \\ - \tau_{s,a}^{stor} \cdot y_{s,a} - Oilprice_a \cdot y_{s,a} \end{array} \right) \quad (12)$$

To represent the decreasing demand for CO<sub>2</sub> during the operation of an EOR facility as described in Section 2.1.2 the CCTSAER model has a dynamic function of the variable storage costs modelled via a modified Golombek cost function (Golombek, Gjelsvik, and Rosendahl 1995). In its generic form the function can be written as:

$$\begin{aligned} c\_y_s \ y_{s,a}, cap\_stor_s &= o_s - \vartheta_s \cdot y_{s,a} + \frac{1}{2} \chi_s \cdot y_{s,a}^2 \\ &\quad - \vartheta_s \cdot cap\_stor_s - y_{s,a} \cdot \log \left( \frac{cap\_stor_s - y_{s,a}}{cap\_stor_s} \right), \\ o_s > 0, \chi_s &\geq 0, \vartheta_s < 0, 0 \leq y_{s,a} \leq cap\_stor_s \end{aligned} \quad (13)$$

Where  $y_{s,a}$  is the current production level and  $cap\_stor_s$  is the available production capacity. The resulting marginal storage costs curve is:

$$\frac{\partial c\_y_s}{\partial y_{s,a}} = o_s + \chi_s \cdot y_{s,a} + \vartheta_s \cdot \log \left( \frac{cap\_stor_s - y_{s,a}}{cap\_stor_s} \right) \quad (14)$$

Following an approach for representing gas production costs presented by Abada et al. (2012) the storage cost function is extended to be dynamic and to depend not only on the current production level  $y_{s,a}$  but on the sum of previous production volumes and current production  $\sum_{b \leq a} y_{s,a}$ . Thus variable

storage costs in one period can be calculated as storage costs for cumulated storage up to the current

$$c\_y_s \left( \sum_{b \leq a} y_{s,a}, cap\_stor_s \right) - c\_y_s \left( \sum_{b < a} y_{s,a}, cap\_stor_s \right) \quad (15)$$

The parameters  $o_s, \chi_s, \vartheta_s$ , are chosen to represent a tripling of the variable cost in case a CO<sub>2</sub>-EOR operation reaches 90% of the anticipated storage capacity. For non EOR storage no marginal cost increase is implemented.

The storage operator can start using the facility after a five year exploration and construction period:

$$y_{s,a} - \sum_{b < a} inv\_y_{s,b} \leq 0 \quad \forall s, a \quad \alpha_{s,a}^{stor} \geq 0 \quad (16)$$

Each storage site has a maximum storage capacity  $cap\_stor_s$ . Therefore, the per period storage volume  $y_{s,a}$  multiplied with the duration of one model period  $a$  and summed over all model periods has to be less or equal to the storage capacity of the respective storage site.

$$\sum_a y_{s,a} \cdot d - cap\_stor_s \leq 0 \quad \forall s \quad \beta_s^{stor} \geq 0 \quad (17)$$

In every model period the entire amount of CO<sub>2</sub> sold from all traders to one storage site has to be balanced through storage activity at this location:

$$\sum_t sales_{t,s,a} - y_{s,a} = 0 \quad \forall s,a \quad \tau_{s,a}^{stor} \text{ free} \quad (18)$$

### 3.2.4 CO<sub>2</sub> Traders' Problem

This model formulation is intended to work as a general set-up that can be applied to a broader spectrum of issues regarding CCTS. Therefore a trader is included to allow for the implementation of regulatory considerations. However, in this first version no regulatory objective is implemented. Thus, each CO<sub>2</sub> trader is simply balancing the discounted cash-flows (19) and the physical flows (16) between the CO<sub>2</sub> emitters, transmission system operators and storage operators.

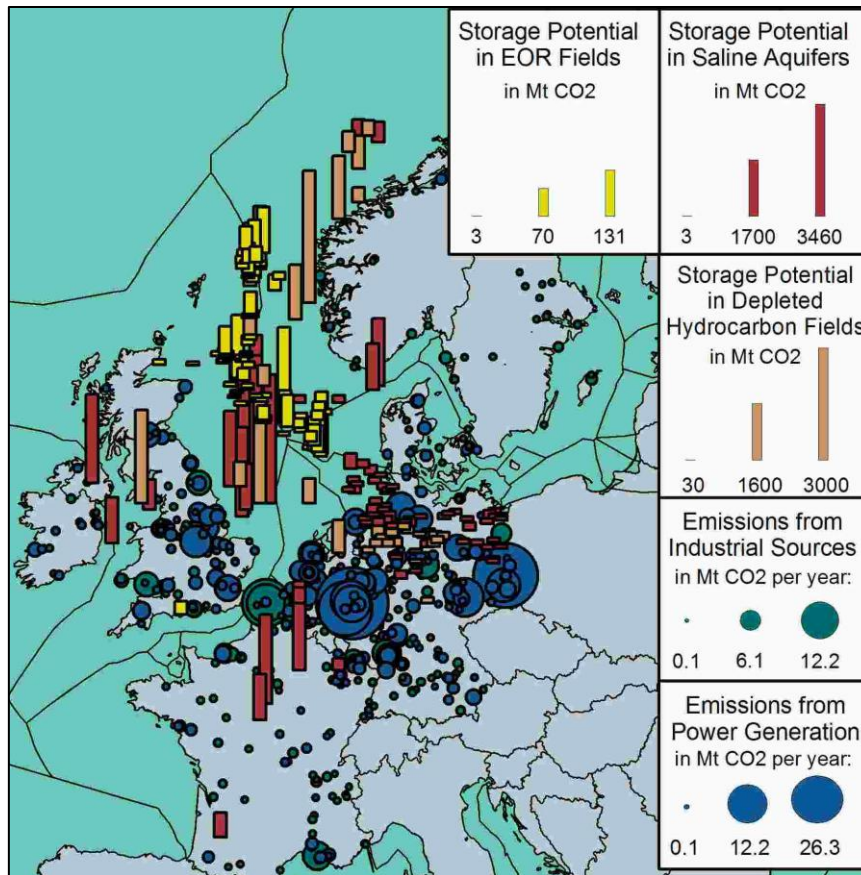
$$\min_{\substack{purchase, \\ sales, t\_flow}} \pi_t = \sum_a \frac{1}{1+r} \cdot \left( \begin{array}{l} + \sum_p \tau_{p,a}^{capt} \cdot purchase_{t,p,a} \\ + \sum_{o,i,j} \tau_{o,i,j,a}^{trans} \cdot t\_flow_{t,i,j,a} \\ + \sum_s \tau_{s,a}^{stor} \cdot sales_{t,s,a} \end{array} \right) \quad (20)$$

$$\begin{aligned} s.t. \quad & \sum_i t\_flow_{t,j,i,a} - \sum_i t\_flow_{t,i,j,a} \\ & sales_{t,s,a} - purchase_{t,p,a} = 0 \quad \forall t,j,a \quad \phi_{t,j,a}^{trader} \text{ free} \end{aligned} \quad (21)$$

### 3.3 Data

The following section describes the data used as input to the CCTSAER model. Core assumptions and simplifications are described and implemented data is presented. Data was collected for the period from 2015 to 2055. Note that the results for model results for 2055 will not be interpreted. This last period is introduced to include an additional pack back period and to allow for investment in 2050. The scope of this study is the North Sea Region including Belgium, the Netherlands, Luxembourg, France, Germany, Denmark, Sweden, Norway, UK, and Ireland, and their respective Exclusive Economic Zones (EEZs). Data on location and emission volumes of refineries, steel and cement production facilities as well as coal- and gas-fired power plants in the North Sea region is taken from a database developed earlier (see Herold et al. 2011). The database assumes an economic life time of 40 years for gas fired and 50 years for coal fired power plants. Facilities are supposed to shut down and not be replaced after the economic life time is reached. The same database was used for location and capacities of potential storage in depleted hydrocarbon fields and saline aquifers. Data on CO<sub>2</sub>-EOR facilities was developed in Section 2.2.2.

Figure 4 illustrates the distribution of emission sources and potential storage sites in the North Sea Region. It also depicts the respective emission source type and its emission volumes for 2010 as well as storage types and respective capacities. Emission sources and storage sites are not equally spread in the North Sea Region. While the largest emission sources are located in the Rhine Area, the largest storage capacities can be found in offshore in the UK and Norwegian EEZs. Denmark, UK and Norway are the only countries that have potential for CO<sub>2</sub>-EOR in their parts of the North Sea.



**Figure 4: Distribution of CO<sub>2</sub> emission sources and potential storage sites by type and volume.**

Source: Own illustration based on data from Herold et al. (2011).

### 3.3.1 Capture Costs

It is undoubted in literature that the initial capture process is the most expensive stage of the CCTS process chain (e.g. Global CCS Institute 2011). There are three major technology options – namely Post-Combustion, Pre-Combustion and Oxyfuel – with different technology maturity and significant variation in investment and variable costs. As the capture process is not the focus of this study assumptions were made to abstract from the respective technologies and to arrive at estimates for incremental overnight capital costs and incremental variable operation and maintenance costs for coal and gas fired power plants and steel, cement and refinery facilities.

For coal and gas-fired power generation, calculations were based on WorleyParsons and Schlumberger (2011). Figures on overnight capital costs for the respective technologies were first converted from US to Europe specific values based on conversion factors presented in the Appendix. In the next step capture rate, load factor and capacity of the respective capture equipped plants were used to convert Euro per ton figures into Euro per tCO<sub>2</sub> captured. For the respective industrial processes estimates on specific capital costs were taken from Kuramochi et al. (2012).

Assumptions						
Load factors <sup>e</sup>		Coal-fired (7500 h)		Gas-fired (6000 h)		
Learning rates	Capital Cost <sup>f</sup>	PC 20%	Oxyfuel 13%	IGCC 15%	NGCC 20%	
	energy penalty <sup>g</sup>	2.5%				
Other factors	Wholesale Electricity Price <sup>h</sup>	91.67 €/MWh				
	Power equivalent factor for steam <sup>i</sup>	0.23 MWh <sub>el</sub> /MWh <sub>th</sub>				
	Currency conversion <sup>j</sup>	1.25 \$/€				
Cost component	Sector	2015	2020	2030	2040	2050
Overnight Capital Costs in [€/tCO <sub>2</sub> captured per year]	Power: Coal-fired <sup>k</sup>	175	175	149	126	107
	Power :Gas-fired <sup>l</sup>	275	275	220	176	141
	Cement <sup>m</sup>	243	243	207	176	150
	Steel <sup>n</sup>	91	91	77	65	55
	Refinery <sup>o</sup>	170	170	145	123	105
O&M Costs in [€/tCO <sub>2</sub> captured]	Power: Coal-fired	10	10	9	7	6
	Power :Gas-fired	7	7	6	5	4
	Cement <sup>m</sup>	21	21	18	15	13
	Steel <sup>n</sup>	5	5	4	3	3
	Refinery <sup>o</sup>	18	18	15	13	11
Energy Penalty Costs in [€/tCO <sub>2</sub> captured]	Power: Coal-fired	54	54	53	51	50
	Power :Gas-fired	47	47	45	44	43
	Cement <sup>m</sup>	16	16	15	15	15
	Steel <sup>n</sup>	28	28	27	26	25
	Refinery <sup>o</sup>	43	43	42	41	40
Sum of Variable Costs in [€/tCO <sub>2</sub> captured]	Power: Coal-fired	64	64	62	58	56
	Power :Gas-fired	54	54	51	49	47
	Cement <sup>m</sup>	37	37	34	31	29
	Steel <sup>n</sup>	33	33	31	29	28
	Refinery <sup>o</sup>	61	61	57	54	51

<sup>e</sup> Own assumption.

<sup>f</sup> Percent decrease per additional 100GW installed (Rubin et al. 2007); 100GW additional capacity is assumed to be constructed each 10 years starting 2020.

<sup>g</sup> Own assumption.

<sup>h</sup> IEA (2012b): Industry electricity wholesale total prices including taxes.

<sup>i</sup> Kuramochi et al. (2012).

<sup>j</sup> XE Corporation (2012)

<sup>k</sup> For coal fired power generation the cost estimate represents the average additional costs calculated for applying PC and oxyfuel technologies.

<sup>l</sup> For gas fired power generation the cost estimate represents the additional costs calculated for combining the NGCC technologies with carbon capture

<sup>m</sup> Kuramochi et al. (2012) suggest different options for cement production with carbon capture. All options require additional steam which is either supplied from electricity purchased at wholesale prices or from an onsite CHP that sells excess electricity back into the network. Presented figures are average value of the different options.

<sup>n</sup> For the steel production all assessed options are retrofit post combustion designs. In general CO<sub>2</sub> capture processes for steelmaking are more mature compared to other industries and Kuramochi et al. (2012) presents several low cost capture options which lead to low average capital and variable costs estimates for capture.

<sup>o</sup> Pres. figures are average estimates of two PC capture processes prop. for petroleum ref. by Kuramochi et al.

**Table 5: Incremental capital and variable costs for carbon capture in the respective power and industry sector.**

**Source:own calculations based on (Kuramochi et al. 2012; Rubin et al. 2007; WorleyParsons and Schlumberger 2011).**

Variable costs of capture consist of two major components: Operations and maintenance costs (O&M costs) and a cost penalty due to increased process energy and heat demand and the resulting efficiency reduction of the respective process. O&M costs for power generation are taken from WorleyParsons and Schlumberger (2011) and converted from Euro per kwh into Euro per tCO<sub>2</sub> captured using the carbon intensity of the respective process. For the industrial processes O&M costs were given as percentage of capital costs. Energy penalties were based on relative efficiency losses for the power generation sector and on additional energy and heat demand for the industrial processes. Heat demand was converted into additional electricity demand by applying a power equivalent factor for steam.

To account for technological improvement, learning rates for the capture technology were applied on capital and operations and maintenance costs (Rubin et al. 2007). For the energy penalty, only a very moderate learning rate of 2.5% per 10 years was employed. This accounts for the opposing effects of anticipated fuel and material costs increase and prospective process efficiency gains. Table 5 summarizes the assumptions made and presents the resulting estimates of overnight capital costs, O&M costs and cost of energy penalty.

The capture rate, i.e. the rate at which CO<sub>2</sub> is captured and not released into the atmosphere, is different for the different technologies. Published capture rates are in the range between 85 and 100% (Finkenrath 2011). While post-combustion is typically associated with lower capture rate, oxyfuel processes can in theory achieve 100% of CO<sub>2</sub> absorption. As no specific assumptions are made on the capture technology choice a maximum capture rate of 90% is assumed for all facilities.

### **3.3.2 Transport costs**

After capturing the CO<sub>2</sub> it needs to be transported to a storage site. Efficient transportation can be accomplished either via pipeline or ship transport. It is assumed that the capturing delivers high purity, conditioned CO<sub>2</sub> ready for transportation and includes the respective additional costs. Onshore pipeline transport faces few technological barriers due to experience in the gas and oil sector and the CO<sub>2</sub> industry for enhanced oil recovery in the U.S.. Offshore pipeline and ship transport are technologically feasible options but haven't been demonstrated on commercial scale, yet. Both on- and offshore pipelines come with high capital cost for the infrastructure and comparably low variable costs mainly for fuelling compressor stations and monitoring (CAPEX ~90%). Ship transport is associated with relatively low upfront costs (CAPEX ~50%). Pipelines highly benefit from economies of scale resulting in strongly decreasing unit costs for higher pipeline capacities, while ships can be more efficient with small quantities and distances longer than 500 km. On the other hand, ship capacity can be ramped up by adding ships while non-utilized pipeline capacity represents sunk costs. Additionally, ships have residual value in hydrocarbon transport which reduces the financial risk (ZEP 2011).

It is worth mentioning that the cross-border transport of CO<sub>2</sub>, which will be necessary if CCTS will be deployed on an European scale, is currently not legal under international environmental protection law. CO<sub>2</sub> transport is regulated under the "Basel Convention" that establishes a regime for the control of the international trade of hazardous wastes. Currently the regulations are being revised to allow for cross-border transport of CO<sub>2</sub> (Global CCS Institute 2011).

Table 6 presents the parameter implemented into the CCTSAER model to represent costs associated with CO<sub>2</sub> transport. Following considerations made in Herold et al. (2011), the costs for offshore pipelines are assumed to be three times higher than for onshore infrastructure.

The gas pipeline network was used to produce a candidate network for potential CO<sub>2</sub> trunk pipeline routes (see Appendix). The underlying assumption is that these routes would face significantly lower right of way costs and face lower public resistance. At the same time the gas pipeline network already connects the main population and industrial centers (where most of the emission sources are located)



to the oil and gas fields of the North Sea (where both the potential CO<sub>2</sub>-EOR operations and regular storage site in depleted hydrocarbon fields are located). All cross-border interconnection points as well as major nodes inside of a country are taken as nodes for the candidate network. CO<sub>2</sub> sources are assigned to nodes of the network based on closest distance and taking into account the respective country affiliation. A feeder connection is assumed for the linkage to the node. Cross-border feeder connections are not allowed. For remote locations in Sweden and Norway a ship connection to Kårstø, Norway is assumed. CO<sub>2</sub> storage sites are clustered based on available data (for CO<sub>2</sub>-EOR fields) and on individual considerations (for depleted hydrocarbon fields and saline aquifers). Dedicated cluster centers (typically the largest oil fields in the region or on central storage site in a formation of saline aquifers) are assumed to be connected to the network via a trunk pipeline. Other cluster members connect to the center via feeder connections.

Cost Component	Carrier	Type	Value in € per tCO <sub>2</sub> km
Capital Costs	Pipeline	Feeder	0.5
		Trunk	0.08
	Ship	0.09	
Variable Costs	Pipeline	Feeder	0.01
		Trunk	0.01
	Ship	0.02	

For offshore pipeline connections a cost escalation factor of 3 was applied on capital and variable costs.

**Table 6: Transportation costs implemented in the CCTSAER model.**

**Source: Own calculations based on (2011).**

### 3.3.3 Storage Costs

In the last stage of the CCTS technology chain the carbon needs safe and long term storage. While the largest storage capacities are found with offshore saline aquifers they are also associated with the highest uncertainty of availability and accessibility. Consequently, these storage sites face higher storage costs compared to the other option of depleted hydrocarbon fields. A joint effort of IEAGHG and ZEP (2011) has identified 8 main cost drivers for storage: Field capacity, well injection rate, liability transfer costs, assumed interest rate, well depth, well completion costs and number of required observation and exploration wells. Based on the variation of these key input parameters cost estimates on overnight capital costs and variable operations and maintenance costs have been developed in the study mentioned above. The least favorable realizations of the respective parameters are taken as input data for the presented model database to account for the uncertainty and to avoid overly optimistic assumptions. Table 7 presents the capital and variable costs for CO<sub>2</sub> storage included in the model database.

	capital costs in €/tCO <sub>2</sub> stored per year	Variable costs in €/tCO <sub>2</sub> stored
Saline Aquifer Offshore	169	6
Depleted Hydrocarbon field Offshore	96	6
Saline Aquifer Onshore	89	4
Depleted Hydrocarbon field Onshore	68	4

**Table 7: Capital and variable costs of CO<sub>2</sub> storage.**

**Source: IEAGHG and ZEP (2011); high scenario.**

### 3.3.4 Estimation of costs for CO<sub>2</sub>-EOR in the North Sea Region

To assess the economics of a potential CO<sub>2</sub>-EOR infrastructure correctly, it is crucial to accurately estimate the associated costs. Based on various case studies on CO<sub>2</sub>-EOR projects in the North Sea an inventory of the main investment and operating costs components was developed (see Table 8).

CAPEX cost component	Mill. €
1) Survey costs to examine the reservoir characteristics with respect to CO <sub>2</sub> -EOR	1.50 <sup>p</sup>
2) Platform construction/restructuring costs to adapt to CO <sub>2</sub> -EOR requirements, including	
a) surface facilities costs to pretreat the CO <sub>2</sub> before injection	17.5 <sup>q</sup>
b) recycle installments to separate, compress and re-inject CO <sub>2</sub> .	7.1 <sup>r</sup>
3) Well drilling costs for new injection wells	52.5 <sup>s</sup>
4) Monitoring and verification facility	3% of CAPEX <sup>t</sup>
OPEX cost component	Mill. €/MtCO <sub>2</sub>
1) Facility operation	5% of CAPEX <sup>u</sup>
2) Oil production	12.1 <sup>v</sup>
3) CO <sub>2</sub> -recycling	5.2 <sup>w</sup>
4) CO <sub>2</sub> compression and injection	8.7 <sup>x</sup>
5) Monitoring and verification	0.4 <sup>y</sup>

<sup>p</sup> BERR (2007)

<sup>q</sup> per MtCO<sub>2</sub>/year injected (water depth >100m); Source: Kemp and Kasim (2012)

<sup>r</sup> per MtCO<sub>2</sub>/year recycled; Source: Kemp and Kasim (2012)

<sup>s</sup> per MtCO<sub>2</sub>/year injected (water depth >100m); Source: Kemp and Kasim (2012)

<sup>t</sup> Kemp and Kasim (2012)

<sup>u</sup> (Source: Holt, Lindeberg, and Wessel-Berg 2009)

<sup>v</sup> per MtCO<sub>2</sub> injected; Source: BERR (2007)

<sup>w</sup> per MtCO<sub>2</sub> recycled; Source: Gozalpour et al. (2005)

<sup>x</sup> per MtCO<sub>2</sub> injected; Source: Gozalpour et al. (2005)

<sup>y</sup> per MtCO<sub>2</sub> stored; Source: BERR (2007)

**Table 8: CAPEX and OPEX cost components for CO<sub>2</sub>-EOR installation.<sup>5</sup>**

Based on the cost components mentioned above investment costs add up to 103.9 € per tCO<sub>2</sub> stored per year and operating costs add up to 36.8 € per tCO<sub>2</sub> stored. Without costs for CO<sub>2</sub> import the costs for oil supply from CO<sub>2</sub>-EOR in the North Sea Region are in the range of 12-17€ per bbl incremental oil with is consistent with estimates from OECD and IEA (2008) giving a range of 30-70\$ per bbl (including costs of CO<sub>2</sub> supply) for long-term oil supply from CO<sub>2</sub>-EOR.

<sup>5</sup> Various conversion rates were applied to arrive at consistent estimates. See Appendix for more details.

## 4 Scenarios of CCTS development in the North Sea Region

Two main categories of results are analyzed and discussed in this section: on the one hand the model set-up allows for a detailed analysis of capture and storage activities on a site-by-site basis. CO<sub>2</sub> streams can be examined in great detail allowing for the identification of transport routes and cross-border shipment volumes. Associated capital costs and variable expenditures of utilizing the technologies can be tracked on a disaggregated level. On the other hand the model enables the analysis of the interactions of the individual entities (traders, CO<sub>2</sub> emitters, CO<sub>2</sub> transmission network operators, and CO<sub>2</sub>-EOR and other storage operators) in a market equilibrium setting. It explicitly calculates market clearing prices of CO<sub>2</sub> at the gate of the capturing facility and CO<sub>2</sub> prices perceived by CO<sub>2</sub> storage operators including the transportation fees. Due to the model set-up, revenues and costs are shared along the CCTS and CO<sub>2</sub>-EOR value chains; i.e. revenues generated by the CO<sub>2</sub>-EOR operator from selling his additionally recovered crude oil to the world market are shared with the capture facilities via the market-clearing price of the CO<sub>2</sub> ( $\tau_{p,a}^{capt}$ ). Vice versa, incentives to invest into CCTS given by the CO<sub>2</sub> certificate price are also taken into account, in lowering the market-clearing price, respectively.

The Appendix gives a comprehensive summary of volumes of CO<sub>2</sub> captured, transported and stored - by industry, storage type and country. It also provides cross-border shipments for each of the four scenarios. Moreover, average market-clearing prices of CO<sub>2</sub> perceived during the initial, CO<sub>2</sub>-EOR driven, CCTS deployment, at the capture facility gate and at the CO<sub>2</sub>-EOR wellhead are summarized, respectively. Additionally, it shows the average prices of storage (including transport) during the later periods.

For better comparability with other studies the cost figures presented are undiscounted and do not incorporate any interest rate or other financial considerations. Cost figures are given in € Bn if not stated otherwise. Volumes of CO<sub>2</sub> are given in MtCO<sub>2</sub> per year if not stated otherwise.

### 4.1 General Scenario Framework

The CCTSAER model can be used to address a variety of different issues regarding the development of CCTS and CO<sub>2</sub>-EOR. It can be employed to examine the effects of regulatory regimes by assigning an alternative objective function to the CO<sub>2</sub> trader or to investigate the implications of limited availability of storage resources or delayed implementation of the technologies. These first runs of the CCTSAER model are intended to understand the main drivers of a potential development of a joint CO<sub>2</sub>-EOR and CCTS infrastructure. It is obvious that deployment is triggered by two key inputs:

1. Expectations about the development of the crude oil price determine the attractiveness of CO<sub>2</sub>-EOR operations. The price not only has to cover investment and variable costs of incremental oil production but also has to account for financing the capture and transport of the CO<sub>2</sub>.
2. The CO<sub>2</sub> certificate price path governs the profitability of the CCTS technology because of the arbitrage between CCTS and purchasing CO<sub>2</sub> certificates to “offset” CO<sub>2</sub> emissions. If in the long run, anticipated prices are higher than the costs of using the technology chain, then CCTS is employed.

Having identified these two determinates of the model outcomes, four scenarios are developed by variation of these input parameters to understand how and to what extent they drive model results.

Estimates on future crude oil prices are obtained from a survey conducted by DOE/IEA (2012). The Medium Oil Price scenario represents an average of the price given in the above mentioned study.

The Low Oil Price scenario assumes a stagnation of the oil price at 95 \$/bbl from 2015 onwards based on more conservative estimates from the same study. For periods beyond 2035 the average trend obtained from prior periods is applied.

The values chosen for the CO<sub>2</sub> prices are in analogy to the prices estimated by the PRIMES model as necessary to achieve CO<sub>2</sub> reduction goals of 40% (52€ per tCO<sub>2</sub> in 2050) and 80% (270€ per tCO<sub>2</sub> in 2050), respectively (EC 2011b). As described in Section 1, CCTS is considered a very important CO<sub>2</sub> mitigation technology with a substantial share of CO<sub>2</sub> emission reduction attributed to its availability and intensive use.

For each of the parameters, two characteristic trajectories are chosen to represent typical assumptions (see Table 9). Although this input data does not represent a comprehensive range of scenarios, their variation can be used to gain valuable insights and help understanding the role CO<sub>2</sub>-EOR can play in the development of CCTS.

Apart from CO<sub>2</sub> and crude oil prices, the availability of storage capacity is a decisive parameter. Especially France, Germany and Belgium have their storage resources mostly in onshore saline aquifers and depleted hydrocarbon fields. However, onshore storage is associated with significantly higher complexity of regulation and a higher number of stakeholders involved. Following a long debate onshore storage was excluded as a storage option in Germany (Hirschhausen et al. 2012). The situation is similar in Denmark (cf. Brøndum Nielsen 2011). UK and Dutch regulation allows offshore storage only (Global CCS Institute 2012). Analogous developments are conceivable for other countries of the North Sea Region. Eventually, offshore storage will most likely be the only remaining option. Therefore, in all presented scenarios onshore storage capacity is not available which reduces total storage capacity from 54 GtCO<sub>2</sub> to 40 GtCO<sub>2</sub>. France and Belgium are mostly affected by this assumption as their storage potential is exclusively located onshore. Despite of minor storage resources (1.2 GtCO<sub>2</sub>) in saline aquifers in the German North Sea, the situation in Germany is similar.

Input Parameter	Variation	2015	2020	2025	2030	2035	2040	2045	2050
Certificate price in €/tCO <sub>2</sub>	Low	14	17	27	37	45	52	52	52
	High	18	25	39	53	75	97	183	270
Crude Oil Price in \$/bbl	Medium	92	106	113	118	118	123	129	135
	Low	95	95	95	95	95	95	95	95

**Table 9: Variation of input parameters implemented for to test the CCTSAER model.**

To increase the plausibility of the scenarios we assume an interest rate of 10%. This high rate has two effects: Although the model setting gives perfect foresight to each firm and investments are safe to be recovered, due to the interest rate and associated discounting of costs, investment decisions are only made in the period before the infrastructure is in fact utilized (incorporating 5 years of construction). Again due to the discounting, a second effect ensures that revenues (e.g. from sales of additionally recovered crude oil) are realized as early as possible.

The discussion of the scenario results is structured as followed: The medium oil price path is taken as the base case assumption. For each of the medium oil price scenarios, a detailed discussion of the deployment of the CCTS and CO<sub>2</sub>-EOR technologies is complemented with an examination of associated costs and average perceived market clearing prices. A sensitivity analysis on the assumed oil price is performed by comparing results to a low oil price case.

## 4.2 Low CO<sub>2</sub> certificate price scenario

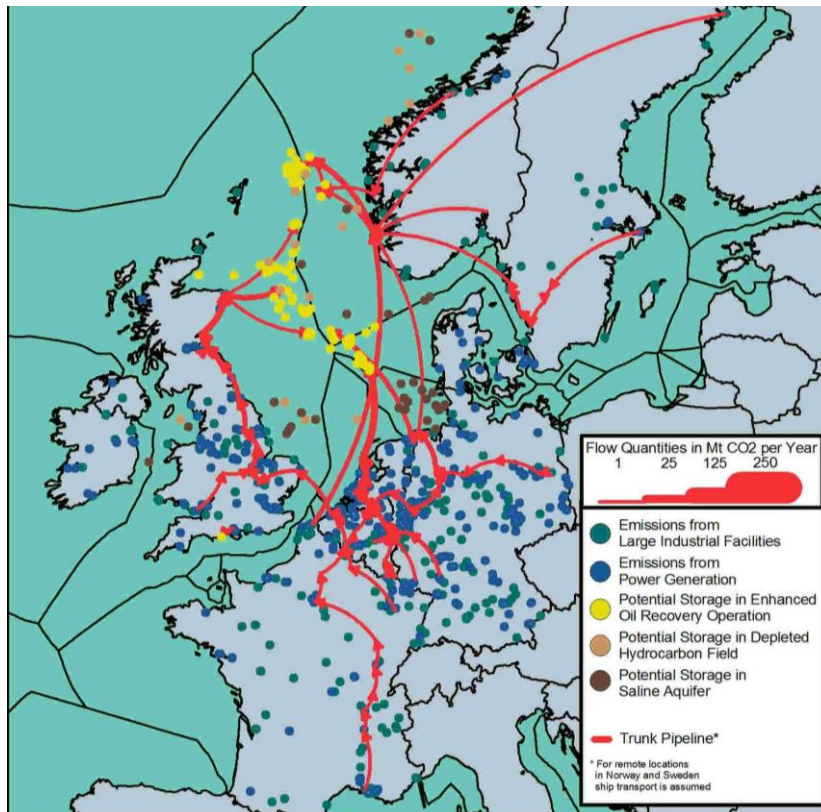
Given the cost parameters assumed for this scenario, the development of CCTS is purely driven by the demand for CO<sub>2</sub> from CO<sub>2</sub>-EOR. As shown in Figure 7 the largest capture volumes of 130.2 MtCO<sub>2</sub> per year occur right after the initial investment period in 2020. The CO<sub>2</sub>-EOR boom lasts for 10 years until 2030 when available storage in CO<sub>2</sub>-EOR operations is used up. In this phase an average 16.5% of the emissions of an individual country are captured using CCTS, with highest values in Norway (36%) and Sweden (38%), and lowest values in Germany (7%) and the Netherlands (6%). The divergence in utilization rates for the different countries results from different structures of their emissions portfolio. While almost 60% of Norwegian CO<sub>2</sub> emissions come from industrial sources (i.e. are cheap to capture), in Germany 77% of the emissions come from coal and gas fired power generation (with high capture costs).

From 2030 to 2035, the capture rate drops to 5.7 MtCO<sub>2</sub> per year and recovers to only 10.7 MtCO<sub>2</sub> per year in 2040 and onwards. This corresponds to an average capture rate of 3%. Highest CCTS utilization in this phase occurs in Norway (17%) while the Netherland and the UK only store 10% and 2%, respectively.

Due to its lowest capital and variable costs, the steel industry is the largest user of the CCTS technology in all model periods. During the boom revenues from CO<sub>2</sub>-EOR make CCTS beneficial even for some cement works, refineries and coal fired power plants. Those sites are large emission sources which are located close to consumption in North Sea oil fields. With equal capital and variable costs assumed for all facilities of one industry, transport costs are the critical cost component.

During this phase large amounts of CO<sub>2</sub> are transported in a 28,200 km long pipeline network. Large cross-border shipments occur from Germany and France to Belgium and further to the Netherlands (17.6 MtCO<sub>2</sub>, 8.8 MtCO<sub>2</sub> and 28.6 MtCO<sub>2</sub>, respectively) and eventually reach the Danish oil fields. UK Central North Sea oil fields are accessed via St. Fergus, Scotland, and are supplied mostly from domestic CO<sub>2</sub> (only 9.6 MtCO<sub>2</sub> are shipped from Zeebrugge to Bacton). The Northern Brent oil field complex which accounts for 30% of the total CO<sub>2</sub>-EOR potential in the UK is linked to Norway via Tampen Link and Kårstø. These sites are served by a large CO<sub>2</sub> stream (20.1 MtCO<sub>2</sub>) from Dunkerque, France, directed to Kårstø, which is joined by CO<sub>2</sub> from Sweden (8.8 MtCO<sub>2</sub>) and further shipped to the UK CO<sub>2</sub>-EOR fields.

Figure 5 illustrates the layout of the CO<sub>2</sub> transport network in 2020. It shows the cross-border connections and flow quantities and depicts how the CO<sub>2</sub> streams merge from the spokes of the system to the major trunk lines.

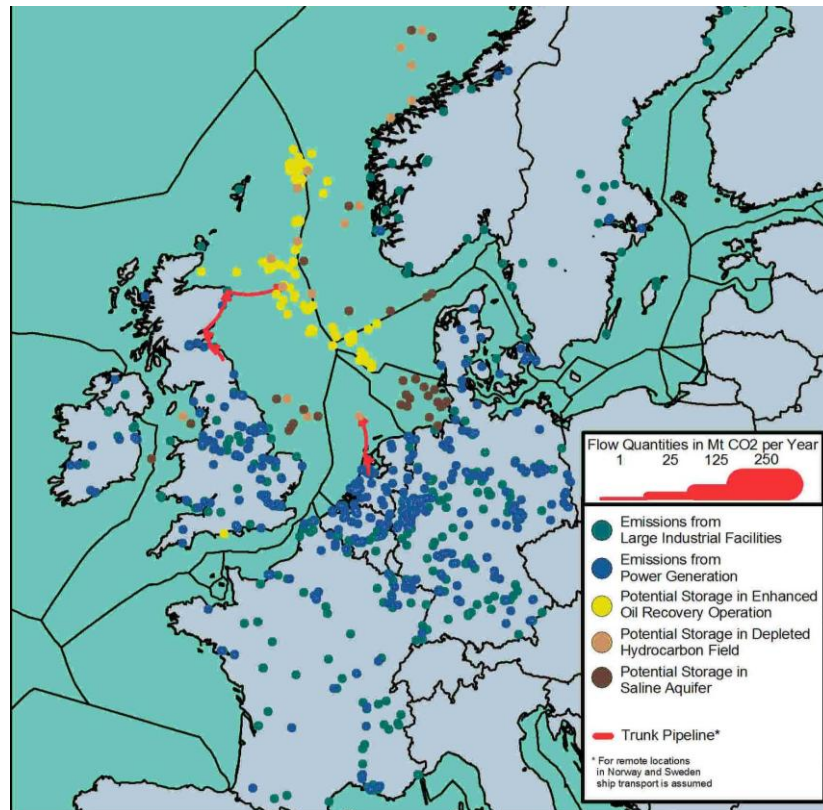


**Figure 5: Low CO<sub>2</sub> - Medium Oil Scenario: CO<sub>2</sub> transport flows in 2020.**

While CO<sub>2</sub> capture is applied in many regions and transported over long distances during the CO<sub>2</sub>-EOR rush, the application of the technology is very limited once CO<sub>2</sub>-EOR capacities are used up. In the post-EOR era the CCTS industry only remains active in the Netherlands, UK, and Norway. The only remaining driver that triggers the utilization of CCTS is the CO<sub>2</sub> certificate price. Although many facilities have invested into the technology before, a CO<sub>2</sub> price of 52€ per tCO<sub>2</sub> in 2050 does not cover the variable costs of carbon capture and transport for most of them. Nor does it cover additional expenditures for developing and operating new storage sites. Exceptions are sites that are located very close to potential new storage sites. In the case of the Netherlands, UK and Norway, depleted hydrocarbon fields in the vicinity of already developed CO<sub>2</sub> transport routes are developed as new storage sites after 2035. The CO<sub>2</sub> streams are fed mainly from a few large steel producers.

Assuming a low CO<sub>2</sub> certificate price and a medium crude oil price, the total costs for the described system add up to Bn. €1076 for the period from 2015 to 2050 including revenues of Bn. €324 from incrementally recovered oil. Figure 10 depicts the development of expenditures for CO<sub>2</sub> certificates, capital and variable costs of CCTS and revenue generated from incrementally recovered oil from 2015 to 2050. Expenditures for balancing emissions with CO<sub>2</sub> certificates account for 89% of these costs. Capital costs make up 45% of the remaining costs. Investments in 2015 initiating the CO<sub>2</sub>-EOR boom split in 29% for capture, 43% for transport and 28% for CO<sub>2</sub>-EOR operation and associated CO<sub>2</sub> storage. During the phase of intensive CO<sub>2</sub>-EOR use, the variable costs on average splits in 40% for CO<sub>2</sub> capture, 15% for transport and 45% for incremental oil production and storage. Note that the costs for storage in CO<sub>2</sub>-EOR oil fields rise when the stored volumes approach capacity because of non-linear cost function used to represent diminishing demand for fresh CO<sub>2</sub> and rising costs of “extraction” of the natural reserve of CO<sub>2</sub> storage. In this phase, average costs of the CCTS technology are in the magnitude of 130 € per tCO<sub>2</sub> captured transported and stored - excluding revenue from CO<sub>2</sub>-EOR. After the boom no new investments in capture facilities are undertaken. Comparably, minor investment into new transport capacity between the established routes and the newly developed storage sites in depleted hydrocarbon fields sum up to €0.2 Bill. In the phase from

2035 to 2050 the share of variable expenditures shifts from storage and transport to capture, due to much shorter transport distances and lower variable cost of storage compared to CO<sub>2</sub>-EOR. In this period capture make up for 71% of variable costs, transport and storage are responsible for 10% and 19%, respectively. In this phase average costs of the CCTS technology are in the magnitude of 50€ per tCO<sub>2</sub> which is in accordance with the CO<sub>2</sub> certificate price.



**Figure 6: Low CO<sub>2</sub> - Medium Oil Scenario: CO<sub>2</sub> transport flows in 2050.**

The market clearing prices for CO<sub>2</sub> are a result of the combined effects of costs associated with investment and variable costs of utilizing the CCTS and CO<sub>2</sub>-EOR technologies on the one hand and incentives to invest into the technologies given by the CO<sub>2</sub> certificate price and the crude oil price on the other hand. During the CO<sub>2</sub>-EOR boom, the weighted average market-clearing price of CO<sub>2</sub> at the gate of the capture facility is 52€ per tCO<sub>2</sub> and the weighted average price of CO<sub>2</sub> delivered to the injection well is 83€ per tCO<sub>2</sub>. In the phase from 2035 to 2050 the weighted average price of CO<sub>2</sub> transport and storage perceived by facilities engaged in CCTS is 20€ per tCO<sub>2</sub> captured. Figure 11 depicts average CO<sub>2</sub> market-clearing prices, transport premiums during the CO<sub>2</sub>-EOR boom from 2020 to 2030, and prices for transport and storage for the later period for each country using the CCTS technology. Due to cheap capture from steel works, Belgium, Germany, France and the Netherlands exhibit the lowest prices. In Norway and Sweden, CO<sub>2</sub> also originates from capture at cement works and refineries and therefore induces higher CO<sub>2</sub> prices. Highest prices are perceived in the UK where CO<sub>2</sub> from coal fired power generation increases the price. Due to longer transportation distances CO<sub>2</sub> received at wellheads in Norway is more expensive than in Denmark. Average prices for CO<sub>2</sub> delivered to the wellhead are highest in UK, due to routing the CO<sub>2</sub> via Tampen Link and Norway. In the post-EOR era, prices of CO<sub>2</sub> storage (including transport) are similar in UK, Norway and the Netherlands and range from 20€ to 21€ per tCO<sub>2</sub>.

### 4.2.1 Oil price sensitivity

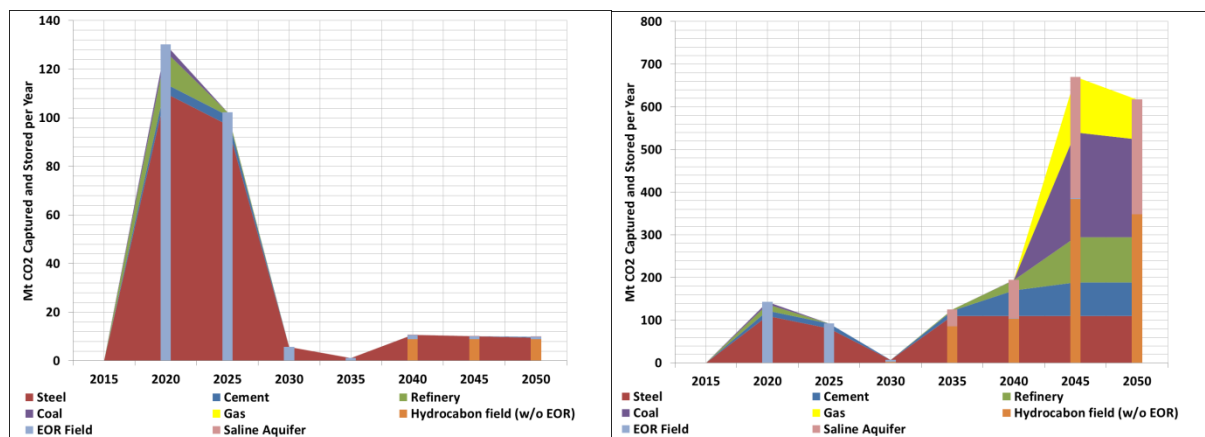
Decreasing the oil price to a low estimate does not change the general pattern of deployment observed in the Low CO<sub>2</sub> price scenario. A phase of intensive CO<sub>2</sub>-EOR utilization from 2020 to 2030 is followed by no significant CCTS deployment in the later periods. The differences are in the details. While some cement works, refineries and even coal-fired power plants supplied the CO<sub>2</sub> demand in the Medium Oil Price case, here the utilization of the carbon capture technology is almost exclusively limited to steel works. Of the overall 108.1 MtCO<sub>2</sub> captured and stored in 2020 only 4.5 MtCO<sub>2</sub> do not come from steel works. Due to a lower crude oil price the CO<sub>2</sub>-EOR potential is exploited less quickly and only 92% of the available CO<sub>2</sub>-EOR storage is used up by 2030, mainly due to decreased supply of the UK Brent field complex via Norway. The CO<sub>2</sub> transport network is shorter and spans over 25,100 km.

Associated revenues generated from CO<sub>2</sub>-EOR operations drop by 17%. Corresponding total system costs increase by 4%. The share of revenues from CO<sub>2</sub>-EOR in the total system costs is 30%. Taking this fact into account the 4% increase in total costs corresponds to a decrease in revenues from CO<sub>2</sub>-EOR of only 12%, or in other words: total costs react slightly inelastic to changes in the crude oil price.

Total volumes of CO<sub>2</sub> stored decrease by 3% compared to the respective reference case. During the CO<sub>2</sub>-EOR boom average costs of the CCTS technology are in the magnitude of 120 € per tCO<sub>2</sub> captured transported and stored - excluding revenue from CO<sub>2</sub>-EOR - which is lower than in reference case. The lower figure is attributed to two reasons: the flatter utilization profile of the CO<sub>2</sub>-EOR storage capacity results in lower storage costs during this phase. Secondly, the change in supply pattern leads to a different market equilibrium with a lower average capture gate market-clearing price of CO<sub>2</sub> of 46€ per tCO<sub>2</sub> (cf. Figure 11). Meanwhile, the average CO<sub>2</sub> purchase price at the CO<sub>2</sub>-EOR wellhead remains at 83€ per tCO<sub>2</sub>. This is due to increased transport costs for CO<sub>2</sub> delivered to UK and Norwegian oil fields which face a decrease in CO<sub>2</sub> supply from domestic production and an increase of imported volumes. In the post-CO<sub>2</sub>-EOR era storage prices are not sensitive to the oil price.

### 4.3 High CO<sub>2</sub> certificate price scenario

A CO<sub>2</sub> certificate price of 270€ per tCO<sub>2</sub> in 2050 is high enough to trigger a Europe-wide and cross-industry application of CCTS by 2050. Again the development can be clearly split into two phases: One CO<sub>2</sub>-EOR driven CCTS development from 2015 to 2030 and one CO<sub>2</sub> price driven evolution from 2035 onwards (cf. Figure 7). The early exploitation of the CO<sub>2</sub>-EOR resources is driven by the interest rate of 10% which substantially discounts future revenues.



**Figure 7: Volumes of CO<sub>2</sub> captured and storage per year by industry and storage type; left: low CO<sub>2</sub> price scenario, right: high CO<sub>2</sub> price scenario.**



The annual storage rate of 143 MtCO<sub>2</sub> per year in 2020 exceeds rates from the low CO<sub>2</sub> price scenario. The increase is attributed to a rise in capture from cement works and refineries. The higher rates are compensated with lower rates in steel making and refineries from 2025 to 2030. By 2030 97% of the CO<sub>2</sub>-EOR storage capacity is used up. The transport network during this phase has a similar shape to the network in the Low CO<sub>2</sub> certificate price scenario (see Figure 5) spans on 30,400 km.

The period from 2030 to 2035 is a transition phase. On the one hand, CO<sub>2</sub>-EOR drops out as a demand for CO<sub>2</sub> while on the other hand, CO<sub>2</sub> certificate prices are not high enough to cover the variable costs of carbon capture, transport and storage (53€ in 2030) yet. Exceptions that continue carbon capture are steel works that exhibit both high emission rates and proximity to storage.

In 2035 the CO<sub>2</sub> certificate price rises to 75€ per tCO<sub>2</sub>. All steel and cement works that are already equipped with carbon capture return to utilizing the technology and are better off than purchasing CO<sub>2</sub> certificates. Investments into new capture facilities are not made before 2035. CO<sub>2</sub> shipment is limited to short distance transports. Each country develops its own storage facility: UK accesses storage in depleted gas fields in the Irish Sea through Point of Ayr and the Central North Sea through St. Fergus, and in saline aquifers in the Southern North Sea through Theddlethorpe; the Netherlands develop a storage facility in a depleted gas field in their executive economic zone which is accessed through Julianadorp; Denmark explores storage in saline aquifers in its part of the North Sea; Norway accesses storage in its depleted hydrocarbon fields in the Heimdal area through Kårstø and in the Norwegian Sea through Trondheim (cf. Figure 8). France and Sweden ship their CO<sub>2</sub> to the Norwegian Kårstø hub using existing transport capacities (22.1 MtCO<sub>2</sub> and 2.3 MtCO<sub>2</sub>, respectively). Cross-border shipments also occur between Belgium and UK (10.2 MtCO<sub>2</sub>). CO<sub>2</sub> captured in the Rhine and Main-Neckar Areas is shipped to Eynatten, Belgium (17.6 MtCO<sub>2</sub>), joins CO<sub>2</sub> from Belgic emissions from the Liege Area and is further shipped to Julianadorp (26.1 MtCO<sub>2</sub>) and the Dutch storage facility. Another small stream is directed directly from the Ruhr Area to the Netherlands (1.9 MtCO<sub>2</sub>). CO<sub>2</sub> from Lower Saxony and Brandenburg in Germany is shipped to small storage facilities developed in offshore saline aquifers in the German North Sea.

With the rising CO<sub>2</sub> price the CCTS technology becomes more and more widely applied across different industries in all countries. By 2045 CCTS is applied in all industries modeled in the CCTSAER model and 90% of a countries' emissions are captured which corresponds to a 100% CCTS deployment as at maximum 90% of the emissions are captured using CCTS. The figure does not change for 2050 and the decline in total volumes captured and stored (from 670.6 MtCO<sub>2</sub> in 2045 to 617.2 MtCO<sub>2</sub> in 2050) is attributed to scrapping coal and gas fired power plants once they have reached their economic lifetime of 50 and 40 years, respectively. As shown in Figure 9 large volumes of CO<sub>2</sub> need to be transported to link CO<sub>2</sub> sources in continental Europe to storage sites in the British and Norwegian North Sea and the Irish Sea. The transportation network spans on 56,200 km. An enormous CO<sub>2</sub> stream of 263.6 MtCO<sub>2</sub> per year is directed from Zeebrugge, Belgium to Bacton, UK. 60% of the total amount of CO<sub>2</sub> captured is stored in UK storage facilities. Germany can only store 27% of their captured emissions in offshore saline aquifers in the German North Sea. The remaining is routed to Norway (117.7 MtCO<sub>2</sub>) where 21% of all storage activities take place and to the UK via Belgium (121.7 MtCO<sub>2</sub>). Due to a lack of offshore storage capacity in France, CO<sub>2</sub> from their capture facilities is routed to UK via Belgium (65.3 MtCO<sub>2</sub>) and to Norway via Dunkerque (24.5 MtCO<sub>2</sub>).

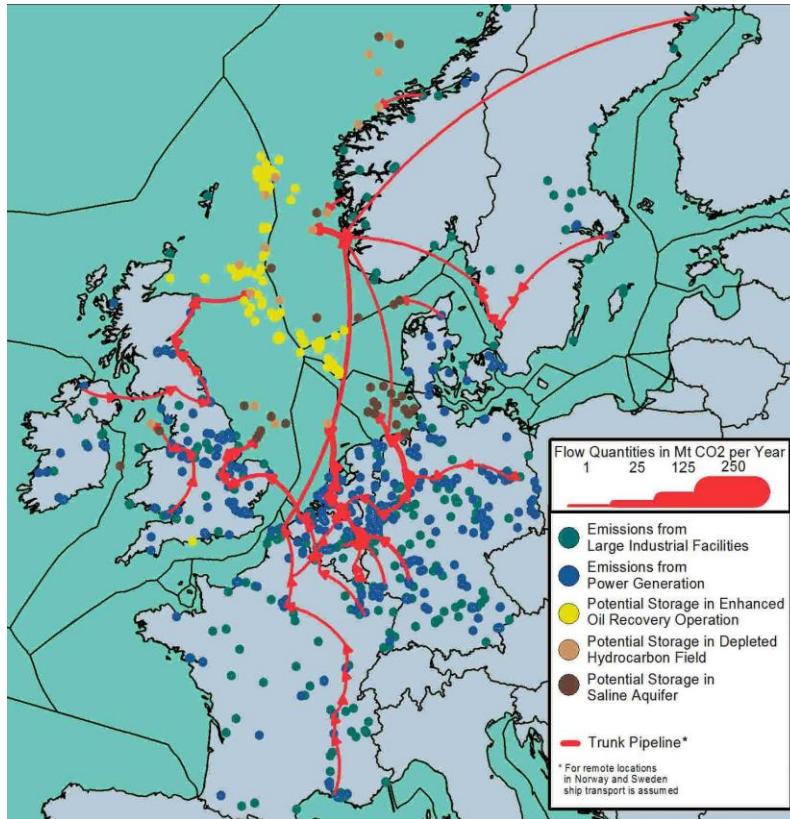


Figure 8: High CO<sub>2</sub> - Medium Oil Scenario: CO<sub>2</sub> transport flows in 2035.

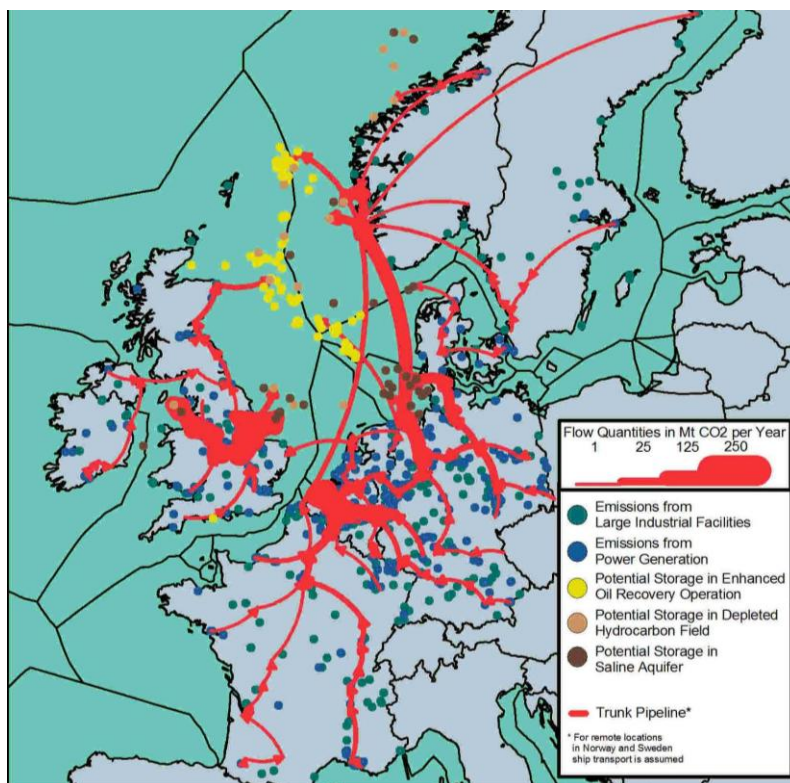
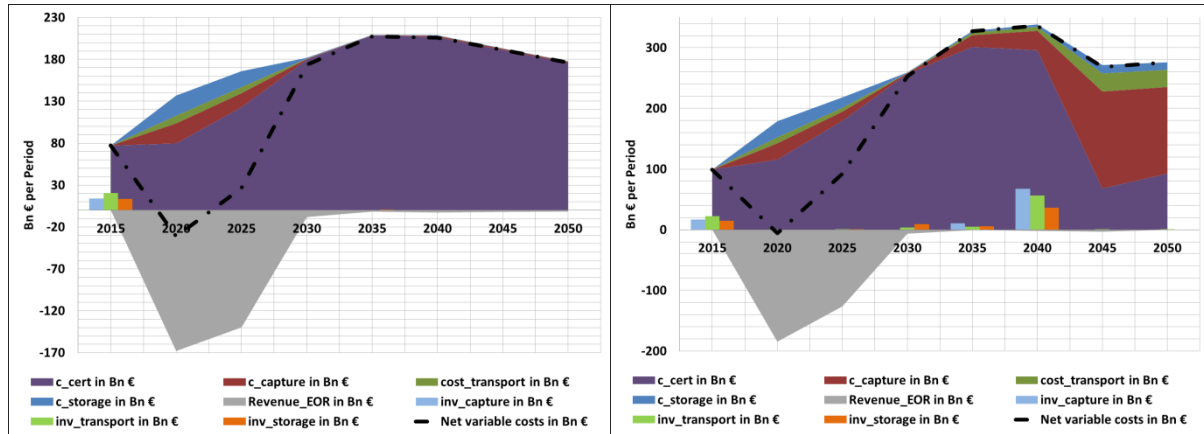


Figure 9: High CO<sub>2</sub> - Medium Oil Scenario: CO<sub>2</sub> transport flows 2050.

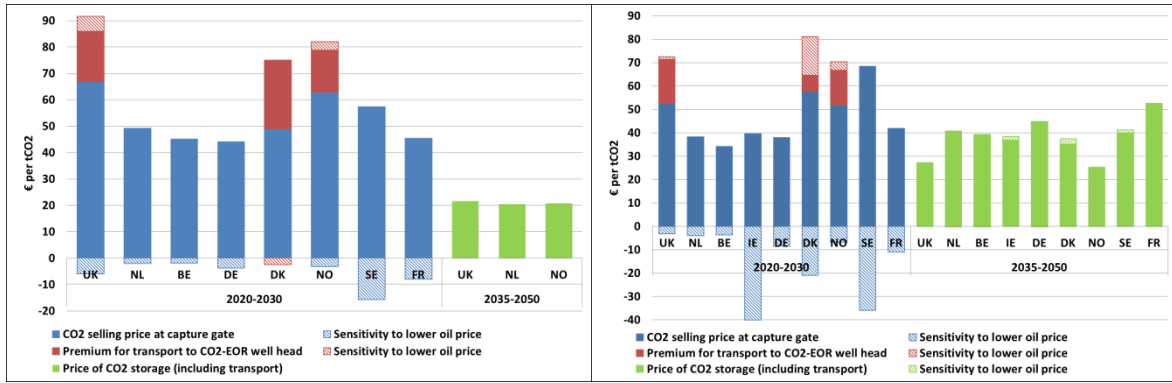
Figure 10 depicts the distribution and magnitude of expenditures and revenue flow over the model horizon from 2015 to 2050. Under the cost assumption of this scenario the total system costs sum up to €1,895 Bn, including a revenue of €323 Bn from sales of additionally recovered crude oil. Capital costs account for 45% of total expenditures. During the phase of intensive CO<sub>2</sub>-EOR utilization the

cost structure in this scenario is similar to the structure presented in the Low CO<sub>2</sub> certificate price Scenario. While no large investments take place in the Low CO<sub>2</sub> scenarios after 2015, there is a second investment phase from 2040 to 2045 in this scenario. During this phase capture investments account for 49%, expenditures for new transport infrastructure for 24% and cost of storage exploration and construction for 27%. In the phase of full CCTS utilization variable capture costs make up the 78% of total running costs while transport and storage account for 15% and 7%, respectively. In this phase average costs of the CCTS technology are in the magnitude of 90€ per tCO<sub>2</sub>.



**Figure 10: Capital and variable costs of carbon capture, transport and storage, expenditures on CO<sub>2</sub> certificates and revenue from incremental oil recovery; left: low CO<sub>2</sub> price scenario, right: high CO<sub>2</sub> price scenario.**

During the CO<sub>2</sub>-EOR boom the average CO<sub>2</sub> market-clearing price perceived at the gate of a capture facility is 46€ per tCO<sub>2</sub>. The average CO<sub>2</sub> purchase price perceived at the CO<sub>2</sub>-EOR wellhead is 70€ per tCO<sub>2</sub>. Both prices are lower than those calculated for the respective “Low CO<sub>2</sub> price scenario”. This is attributed to three reasons: First, the CO<sub>2</sub> certificate price that is implicitly included in the market-clearing price of the CO<sub>2</sub> is higher in the High CO<sub>2</sub> price scenario than in the Low CO<sub>2</sub> price scenarios. Therefore the incentive to sell the CO<sub>2</sub> is higher and respective prices are lower. Second, the amortization period for the investments in capture and transport infrastructure are longer because the facilities are intensively used during the second phase of CO<sub>2</sub> certificate price driven CCTS deployment. The third reason comes from a different configuration of CO<sub>2</sub> supply inside of the respective countries. In UK the increase of supply from cement works lowers the price. The same is true for Norway. The opposite effect can be observed with the equipment of Swedish refineries with carbon capture which increases domestic CO<sub>2</sub> market-clearing prices. In the post-CO<sub>2</sub>-EOR era the average storage prices of 41€ per tCO<sub>2</sub> is significantly higher than in the respective low CO<sub>2</sub> price scenario. This is attributed to new, large investments in transport and storage infrastructure needed to cope with the radical deployment of the CCTS technology. Highest prices are perceived in France and Germany that do not have sufficient, close offshore storage opportunities and need to route their CO<sub>2</sub> to storage facilities in Norway and UK. Countries like UK and Norway that do have extensive offshore storage opportunities exhibit the lowest prices.



**Figure 11: Average CO<sub>2</sub> market-clearing prices by country; left: low CO<sub>2</sub> price scenario, right: high CO<sub>2</sub> price scenario.**

### 4.3.1 Oil price sensitivity

The development of infrastructure, costs and prices during the era of intensive CO<sub>2</sub>-EOR utilization from 2020 to 2030 is very similar to the one in the Low CO<sub>2</sub> certificate price scenario. Lowering the oil price results in a flatter CO<sub>2</sub> injection profile with a capture rate of 118.4 MtCO<sub>2</sub> in 2020 and 95% of CO<sub>2</sub>-EOR storage capacity used up by 2030. A change in supply pattern analogous to the low CO<sub>2</sub> price sensitivity case can be observed. From 2020 to 2030 required transportation infrastructure decrease to 28,000 km.

The ramp-up of CCTS infrastructure is slower than in the respective reference case. With an average of 17%, compared to 20%, the CCTS deployment rate in 2035 is lower in all countries but Belgium, Norway and the Netherlands. With 28%, as compared to 35% in the reference case the divergence is even bigger in 2040. The reason for this lag is the different CO<sub>2</sub> supply pattern during the CO<sub>2</sub>-EOR boom. Refineries and cement works that have invested into capture facilities early only face variable costs of carbon capture and therefore restart to utilize their capture units earlier. In this scenario these facilities do not participate in the first CCTS deployment phase. In the second phase higher incentives, i.e. a higher CO<sub>2</sub> certificate price, is required to trigger investments into capture units. By 2045 when the CO<sub>2</sub> certificate price is at 183€ per tCO<sub>2</sub> the deployment rates are again equalized. In both cases this price induces a full CCTS deployment in all industries and captured amounts correspond to the assumed maximum capture rate of 90%.

Despite a decrease of 16% in revenue generated from CO<sub>2</sub>-EOR compared to the respective reference case total costs only increase by 2%. These revenues make up 17% of the total costs. Taking this into account the 2% increase in total costs corresponds to a decrease in revenues from CO<sub>2</sub>-EOR of only 13%. Similar to the Low CO<sub>2</sub> certificate price scenario, this value again indicates a slightly inelastic relation between total system costs and the assumed crude oil price. Due to full CCTS implementation in both cases the different CO<sub>2</sub> supply patterns during the CO<sub>2</sub>-EOR phase only marginally change the total amounts of CO<sub>2</sub> stored over the entire model horizon.

In correspondence with the CO<sub>2</sub> supply pattern during the CO<sub>2</sub>-EOR boom described above, the average market-clearing prices of CO<sub>2</sub> and associated average transportation premiums perceived in with lower oil prices deviate from figures estimated for the respective reference scenario. Due to the drop-out of expensive supply from cement works, refineries and coal-fired power plants the average CO<sub>2</sub> market-clearing price is estimated to be as low as 36€ per tCO<sub>2</sub>. The lower price is mostly offset by an increase of the transport premium which originates from longer transport distances of CO<sub>2</sub> from German sources to Danish and UK oil fields. Still, the average CO<sub>2</sub> price perceived at the CO<sub>2</sub>-EOR wellhead is 67€ per tCO<sub>2</sub>, which constitute a decrease of 3€ per tCO<sub>2</sub> compared to the respective reference case.

## 5 Conclusions and Further Research

The study examined the role CO<sub>2</sub>-EOR can play in the development of a CCTS infrastructure in the North Sea Region. At first, based on a literature review of selection criteria a comprehensive estimate of additionally recoverable crude oil, associated CO<sub>2</sub> storage potential and respective investment and variable costs was developed for UK, Norwegian and Danish oil fields in the North Sea, on a field-by-field basis. Of the total 1.2 GtCO<sub>2</sub> storage capacity, the UK contributes the highest share of 572 MtCO<sub>2</sub> which corresponds to an additional oil recovery potential of 1733 Mbbl. Overnight capital costs are estimated as 104€ per net tCO<sub>2</sub> stored while variable costs including oil production and CO<sub>2</sub> recycling costs sum up to 37€ per net tCO<sub>2</sub> stored.

The estimated data is combined with a comprehensive database on location and emission volumes and respective CCTS costs of large CO<sub>2</sub> emission sources in the riparian countries of the North Sea (UK, Ireland, Norway, Sweden, Denmark, Germany, France, Belgium and the Netherlands) which was developed in Herold et al. (2011).

Building up on a review of recent CCTS infrastructure models an original model is developed that is able to combine the techno-economic particularities of the CCTS technology with the specific challenges of the CO<sub>2</sub>-EOR technology. The Carbon Capture, Transport, Storage and Enhanced Recovery (CCTSAER) model represents a unique equilibrium model of CO<sub>2</sub> supply from large emission sources and CO<sub>2</sub> demand from CO<sub>2</sub>-EOR operations. The model incorporates endogenous decisions about carbon capture and storage investments, as well as capture and injection quantities based on given costs, CO<sub>2</sub> certificate prices, storage capacities, point source emissions and potential revenues from CO<sub>2</sub>-EOR, on a site-by-site basis. CO<sub>2</sub> transport is modeled to be accomplished by a regulated entity that invests into ship and pipeline capacity to route the CO<sub>2</sub> streams in a cost-efficient way. The layout of the potential CO<sub>2</sub> transport network is based on the European gas pipeline network. A detailed representation of the decreasing demand for fresh CO<sub>2</sub> for CO<sub>2</sub>-EOR operation is accomplished via an exponential cost function that penalizes injection of fresh CO<sub>2</sub> depending on the amount already stored.

The model results indicate that investments in CO<sub>2</sub>-EOR operations in mature oil fields in the North Sea Region are beneficial and the assumed potential is fully exploited in all scenarios. In the period from 2020 to 2030 the CCTS technology is deployed mostly in the steel making sector which faces the lowest cost associated with carbon capture. In this period an average of 113 MtCO<sub>2</sub> per year is estimated to be transported on a 25,000 to 30,000 km transportation network. Germany, France, Belgium and the Netherlands export their CO<sub>2</sub> to Danish and Norwegian oil fields. Despite a possible connection from Continental Europe to the UK, the oil fields in the UK Central North Sea are mainly supplied from the domestic market that covers on average 12% of the country's emissions. By 2030 CO<sub>2</sub>-EOR resources are at least 92% depleted and capture activities decline in all countries.

Capture and transport infrastructure developed during the initial phase of CO<sub>2</sub>-EOR driven CCTS deployment can be fully utilized and combined with regular storage in saline aquifers and depleted hydrocarbon field in later periods. Therefore, variations of the crude oil prices have shown to influence the later path of CCTS deployment once CO<sub>2</sub>-EOR potential is exploited. In particular, the dissemination of carbon capture in the different industry sectors has shown some sensitivity to the assumed oil price path. Variations of this input parameter have identified refineries and cement works in UK and Sweden to be the marginal suppliers to the CO<sub>2</sub>-EOR driven demand for CO<sub>2</sub>. In case of lower crude oil prices their supply can be partly substituted by cheaper CO<sub>2</sub> from steel works in Germany.

Assuming a low CO<sub>2</sub> certificate price of 52€ per tCO<sub>2</sub> in 2050, carbon capture is only applied in few facilities in the steel sector, once revenues streams from CO<sub>2</sub>-EOR dry up. Due to higher investment

and variable costs it is not applied in the power generation sector and remains a local phenomenon where additional favorable circumstances of proximity to cheap storage options in offshore depleted hydrocarbon fields and infrastructure built-up during the CO<sub>2</sub>-EOR boom are given. These conditions only apply for some sites in UK, the Netherlands and Norway. Total annual storage volumes do not exceed 11 MtCO<sub>2</sub>.

A CO<sub>2</sub> certificate price in the range of 180€ per tCO<sub>2</sub> in 2045 is able to incentivize a full deployment of the CCTS technology in all emission intensive industries. From 2035 to 2040 a lower ramp-up speed can be observed in the case where low crude oil prices are assumed. By 2045 the different ramping speeds are balanced out and 670 MtCO<sub>2</sub> per year are captured in both cases. The UK develops as a center of CO<sub>2</sub> storage with volumes of 386 MtCO<sub>2</sub> stored in offshore saline aquifers and depleted hydrocarbon fields in the Central North Sea and the Irish Sea. The respective transportation network spans over 56,200 km.

In a nutshell, CO<sub>2</sub>-EOR does add value to CCTS operations but the potential is very limited and does not automatically induce long term carbon capture and storage activity. Besides, the carbon footprint of this technology needs to be investigated in more detail and can further reduce the potential benefits for CCTS if included into the calculation of net CO<sub>2</sub> reductions.

There is high regulatory uncertainty on the acceptance of CO<sub>2</sub> abatement credentials generated from CO<sub>2</sub>-EOR. For further research it is worth to examine the impact of different climate policy regulations on the technology complex. This can possibly be accomplished with a multi-objective optimization. At the moment, the CO<sub>2</sub> utilization efficiency is an input parameter in the model. In order to represent the full carbon effects of the CO<sub>2</sub>-EOR technology it could be modeled as an endogenous variable. The trader that would represent a governmental entity of an individual country would pursue the two objectives of maximizing revenue and achieving emission reduction targets.

Moreover, prices paid for CO<sub>2</sub> delivered at the CO<sub>2</sub>-EOR wellhead estimated in the model scenarios range between 67€ and 83€ per tCO<sub>2</sub>. Due to the model set-up of shared revenues along the CCTS technology chain these values are probably overestimated. Current prices of CO<sub>2</sub> supplied from natural and anthropogenic sources (gas processing and fertilizer plants in the U.S.) are in the range of \$3 to \$26 per tCO<sub>2</sub> (Global CCS Institute and Parsons Brinckerhoff 2011). Most certainly there would be a feedback between the CO<sub>2</sub> certificate price and the price of CO<sub>2</sub> used for CO<sub>2</sub>-EOR.

Representing this link in the model would add more accuracy to the estimates of CO<sub>2</sub> market-clearing prices.

Besides, the model could be expanded to incorporate the technological constraints of the CCTS and CO<sub>2</sub>-EOR technologies in more detail. In reality, the CO<sub>2</sub> output of a facility is not constant over time and exhibits a significant fluctuation over the year, especially for the power generation sector. Moreover, coal-fired generation has seen significant decrease in load rates due to a flexibilization of the electric system over the last years. One implication would be longer amortization periods for capture investments that change the economics of CCTS in the power sector. On the CO<sub>2</sub>-EOR side, oil production rates could be represented more accurately. The rate of oil production is linked to remaining reserves by the so-called “decline curve” and rapidly decreases once the field has reached a certain maturity (Fetkovich 1980). Accordingly, the revenue stream from the respective operation follows the same pattern.

## 6 Appendix

### Abbreviations

API gravity	American Petroleum Institute gravity
CAPEX	Capital expenditures
CCTS	Carbon capture, transport and storage
CDM	Clean Development Mechanism
CER	Certified Emission Reductions
CHP	Comined heat and power
CO <sub>2</sub> -TSO	CO <sub>2</sub> transmissions system operator
EEZ	Exclusive economic zone
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
GSGI	Gravity stable gas injection
IGCC	Integrated gasification combined cycle
MCP	Mixed complementarity problem
MIP	Mixed integer problem
MMP	Minimum miscible pressure
NGCC	Natural Gas combined cycle
NIMBY	Not in my backyard
OPEX	Operational expenditures
O&M costs	Operations and maintenance costs
OOIP	Original oil in place
PC	Post-combustion
R&D	Research and development
WAG	Water altering gas
WTI	Western Texas intermediate

# Candidate CO<sub>2</sub> network

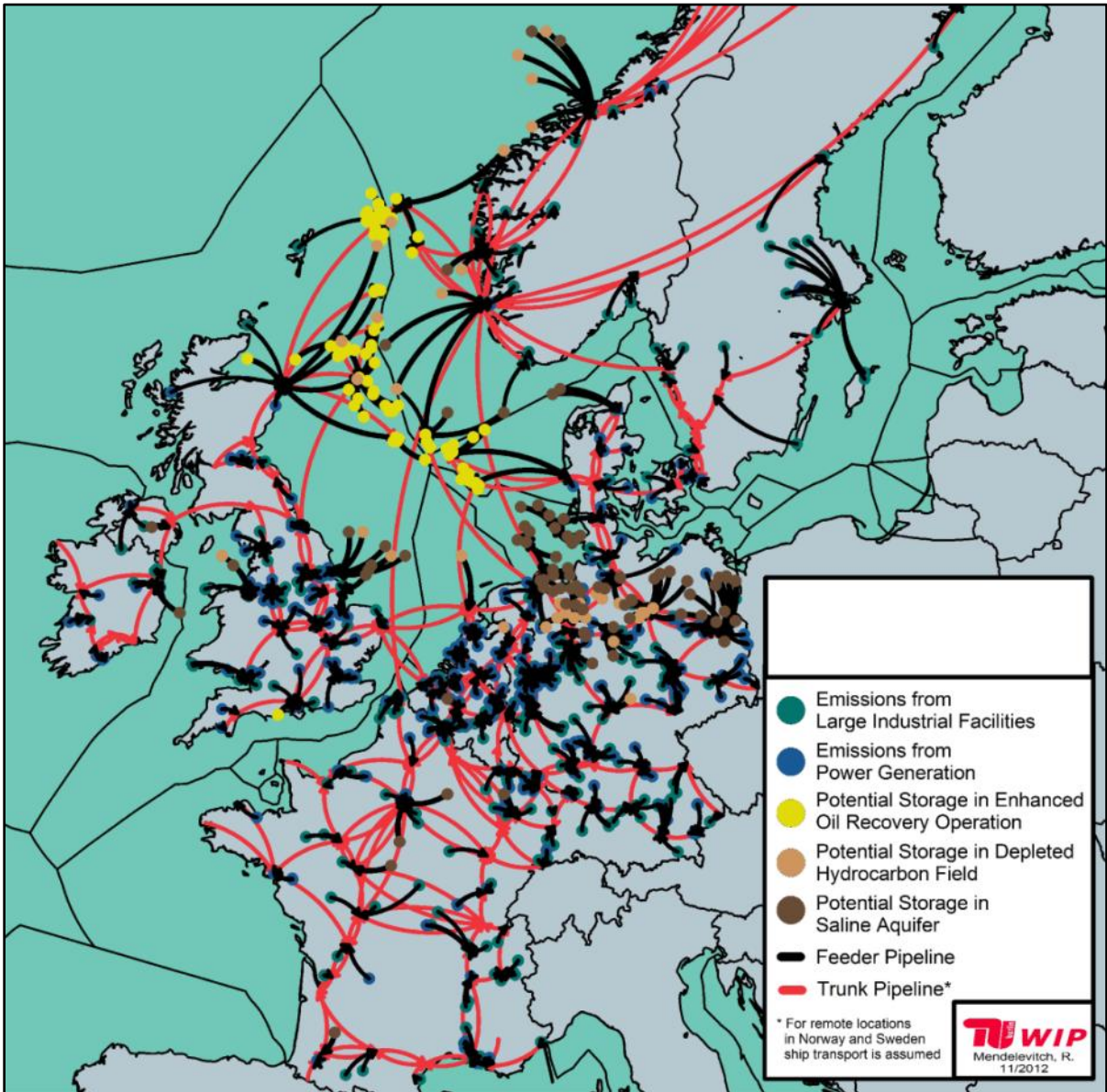


Figure 12: Candidate CO<sub>2</sub> network with feeder and trunk pipeline connections and assignment of emission sources and storage sites by type.



## List of set, parameters and variables

	Description	Data
<b>Sets and aliases</b>		
Node i	Node in model database	geographical location potential connections
Alias: j		
Subset: p	Node where a CO <sub>2</sub> emitter is located	geographical location emissions per year investment cost variable cost
Subset: s	Node where a storage operated is located	geographical location storage capacity investment cost variable cost
Subset: EOR	Node where an EOR operation is located	geographical location storage capacity investment cost variable cost
Trader t	Regulatory entity regulating the trader of CO <sub>2</sub> and perusing other possibly environmental objectives	
Transmission System Operators (CO <sub>2</sub> -TSO): o	Regulated entity managing the physical CO <sub>2</sub> flow	layout of potential CO <sub>2</sub> pipeline network is based on current structure of gas pipeline network
<b>Variable</b>		
f(o,i,j,a)	flow of o from i to j in period a in Mtpa	positive
x(p,a)	CO <sub>2</sub> captured by emitter p in period a	positive
y(s,a)	CO <sub>2</sub> stored by storage operator s in period a	positive
inv_x(p,a)	investment in capture facility by emitter p in period a	positive
inv_f(o,i,j,a)	investment in transport infrastructure from i to j by o in period a	positive
Inv_y(s,a)	investment in storage facility by storage operator s in period a	positive
t_flow(t,i,j,a)	trade of trader t from i to j in period a	positive
purchase(t,p,a)	purchase volumes of trader t from emitter p	positive
sales(t,s,a)	sales volumes of trader t to storage operator s	positive
tau_capt(t,p,a)	Market-clearing price for CO <sub>2</sub> capture by emitter p in period a	free
tau_trans(t,i,j,a)	Regulated tariff for CO <sub>2</sub> transport; refunding CO <sub>2</sub> -TSO for transport investments and variable costs	free
tau_stor(t,s,a)	Storage fee ; refunding storager for Storage investment and variable cost	free

**Table 10: List of sets, parameters and variables used in the CCTSAER model.**

**Source: Own model development.**

## Karush-Kuhn-Tucker conditions of the CCTSAER model

### Trader

$$0 \leq \frac{1}{1+r} \cdot \sum_o \tau_{o,i,j,a}^{trans} + \phi_{t,j,a}^{trader} - \phi_{t,i,a}^{trader} \perp t\_flow_{t,i,j,a} \geq 0 \quad \forall t,i,j,a \quad (22)$$

$$0 \leq \left( \frac{1}{1+r} \cdot \tau_{s,a}^{stor} \right) - \phi_{t,i,a}^{trader} \perp sales_{t,s,a} \geq 0 \quad \forall t,s,a \quad (23)$$

$$0 \leq \frac{1}{1+r} \cdot \tau_{p,a}^{capt} + \phi_{t,j,a}^{trader} \perp purchase_{t,p,a} \geq 0 \quad \forall t,p,a \quad (24)$$

### Trader Clearing Condition

$$\begin{aligned} \sum_i t\_flow_{t,j,i,a} - \sum_i t\_flow_{t,i,j,a} \\ + sales_{t,s,a} - purchase_{t,p,a} = 0 \quad \perp \phi_{t,j,a}^{trader} \text{ free} \quad \forall t,i,a \end{aligned} \quad (25)$$

### CO<sub>2</sub> Emitter

$$0 \leq \frac{1}{1+r} \cdot c\_inv\_x_{p,a} - \sum_{b>a} \alpha_{p,b}^{capt} \perp inv\_x_{p,a} \geq 0 \quad \forall p,a \quad (26)$$

$$0 \leq \frac{1}{1+r} \cdot c\_x_{p,a} - cert_a - \tau_{p,a}^{capt} + \beta_{p,a}^{capt} + \alpha_{p,a}^{capt} \perp x_{p,a} \geq 0 \quad \forall p,a \quad (27)$$

$$x_{p,a} - \sum_{b<a} inv\_x_{p,b} \leq 0 \quad \perp \alpha_{p,a}^{capt} \geq 0 \quad \forall p,a \quad (28)$$

$$x_{p,a} - co2_{p,a} \leq 0 \quad \perp \beta_{p,a}^{capt} \geq 0 \quad \forall p,a \quad (29)$$

### Emitter-Trader Clearing Condition

$$x_{p,a} - \sum_t purchase_{t,p,a} = 0 \quad \perp \tau_{p,a}^{capt} \text{ free} \quad (30)$$

### Pipeline Operator

$$0 \leq \left( \frac{1}{1+r} \cdot c\_inv\_f_{i,j,a} \right) - \sum_{b>a} \alpha_{o,i,j,b}^{trans} \perp inv\_f_{o,i,j,a} \geq 0 \quad \forall o,i,j,a \quad (31)$$

$$0 \leq \frac{1}{1+r} \cdot c\_f_{i,j,a} - \tau_{o,i,j,a}^{trans} + \alpha_{o,i,j,a}^{trans} \perp f_{o,i,j,a} \geq 0 \quad \forall o,i,j,a \quad (32)$$

$$f_{o,i,j,a} - \sum_{b<a} inv_{-}f_{o,i,j,b} \leq 0 \quad \perp \quad \alpha_{o,i,j,a}^{trans} \geq 0 \quad \forall o,i,j,a \quad (33)$$

#### Pipeline Operator Trader Clearing Condition

$$\sum_t t\_flow_{t,i,j,a} - f_{o,i,j,a} = 0 \quad \perp \quad \tau_{o,i,j,a}^{trans} \text{ free} \quad (34)$$

#### Storage Operator

$$0 \leq \frac{1}{1+r} \cdot c_{-}inv_{-}y_{s,a} - \sum_{b>a} \alpha_{s,b}^{stor} \quad \perp \quad inv_{-}y_{s,a} \geq 0 \quad \forall s,a \quad (35)$$

$$0 \leq \frac{1}{1+r} \cdot \begin{pmatrix} O_s + \chi_s \cdot y_{s,a} \\ +\vartheta \cdot \log \left( \frac{cap_{-}stor_s - \sum_{b \leq a} y_{s,a}}{cap_{-}stor_s} \right) \\ -\tau_{s,a}^{stor} - Oilprice_{s,a} \end{pmatrix} + \alpha_{s,a}^{stor} + \beta_s^{stor} \quad \perp \quad y_{s,a} \geq 0 \quad \forall s,a \quad (36)$$

$$y_{s,a} - \sum_{b<a} inv_{-}y_{s,b} \leq 0 \quad \perp \quad \alpha_{s,a}^{stor} \geq 0 \quad \forall s,a \quad (37)$$

$$\sum_a y_{s,a} - cap_{-}stor_s \leq 0 \quad \perp \quad \beta_s^{stor} \geq 0 \quad \forall s,a \quad (38)$$

#### Storage-Trader Clearing Condition

$$\sum_t sales_{t,s,a} - y_{s,a} = 0 \quad \perp \quad \tau_{s,a}^{stor} \text{ free} \quad (39)$$

## Conversion Rates

From	To	multiply with	Source
\$	€	0.8	<a href="http://www.x-rates.com/calculator/">http://www.x-rates.com/calculator/</a> accessed at 14:31, on September 12 <sup>th</sup> 2012.
Pound	€	1.25	<a href="http://www.x-rates.com/calculator/">http://www.x-rates.com/calculator/</a> accessed at 14:32, on September 12 <sup>th</sup> 2012.
Pound 2005	Pound 2011	1.22	<a href="http://www.bankofengland.co.uk/education/Pages/inflation/calculator/flash/default.aspx">http://www.bankofengland.co.uk/education/Pages/inflation/calculator/flash/default.aspx</a> accessed at 14:35, on September 12 <sup>th</sup> 2012.
\$ 2005	\$ 2011	1.15	<a href="http://www.bls.gov/data/inflation_calculator.htm">http://www.bls.gov/data/inflation_calculator.htm</a> accessed at 14:29, on September 12 <sup>th</sup> 2012.
bbl	tCO <sub>2</sub>	0.33	various authors, e.g. Tzimas et al. 2005 <a href="http://www.netl.doe.gov/energy-analyses/pubs/Electricity%20Use%20of%20CO2-EOR.pdf">http://www.netl.doe.gov/energy-analyses/pubs/Electricity%20Use%20of%20CO2-EOR.pdf</a>
kwh/bbl		70	accessed at 12:41, on September 20 <sup>th</sup> 2012. <a href="http://www.storeco2now.com/sites/default/files/education/co2injectiongeolstorage_pres.pdf">http://www.storeco2now.com/sites/default/files/education/co2injectiongeolstorage_pres.pdf</a>
Mscf	tCO <sub>2</sub>	18.95	accessed at 21:10, on September 19 <sup>th</sup> 2012.
Sm3	Bbl	6.25	(Mathiassen 2003)

**Table 11: Conversion rates and other key figures applied in cost and other calculations.**

## Detailed scenario results

All figures presented here are model results from the CCTSAER model implementing the respective scenario input data.

Item	Unit	Period	Scenario			
			Low CO <sub>2</sub> Medium Oil	Low CO <sub>2</sub> Low Oil	High CO <sub>2</sub> Medium Oil	High CO <sub>2</sub> Low Oil
<b>CO<sub>2</sub> market-clearing price</b>						
At capture facility gate	[€ per tCO <sub>2</sub> ]	2020-2030	52	46	46	36
At CO <sub>2</sub> -EOR injection well	[€ per tCO <sub>2</sub> ]	2020-2030	83	83	70	67
Price of T & S	[€ per tCO <sub>2</sub> ]	2035-2050	20	22	41	42
CO <sub>2</sub> stored per year	[MtCO <sub>2</sub> /a]	2020-2030	116.3	107.3	117.8	112
	[MtCO <sub>2</sub> /a]	2035-2050	8	8.3	330.1	324.9
Share of emissions from industry	[%]	2020-2030	99	100	98	100
	[%]	2035-2050	100	100	62	61
Transport Infrastructure constructed	[tsd. km]	by 2030	28.2	25.5	30.4	28
	[tsd. km]	by 2050	28.2	25.5	56.2	56.2
<b>Storage used</b>						
All storage sites	[%]	by 2030	3	3	3	3
	[%]	by 2050	3	3	15	15
CO <sub>2</sub> -EOR storage sites	[%]	by 2030	95	92	97	95
	[%]	by 2050	100	100	100	100

**Table 12: Summary of Scenario Results.**

## Low CO<sub>2</sub> - Medium Oil Price Scenario

	2015	2020	2025	2030	2035	2040	2045	2050
<b>Sum of costs in Bn € per period</b>								
Capture capital costs	13.7	-	-	-	-	-	-	-
Capture variable costs	-	23.9	16.6	0.9	0.2	1.6	1.4	1.4
Expenditures for CO <sub>2</sub> certificates	77.2	79.7	123.0	179.7	208.8	206.5	191.1	175.7
Transport capital costs	20.7	-	-	-	0.2	-	-	-
Transport variable costs	-	9.2	7.4	0.3	0.1	0.2	0.2	0.2
Storage capital costs	13.5	-	-	-	0.6	-	-	-
Storage variable costs	-	24.1	18.9	1.1	0.2	0.5	0.4	0.4
Sum of capital costs	48.0	-	-	-	0.8	-	-	-
sum of variable CCTS costs	-	57.2	42.9	2.2	0.4	2.3	2.1	1.9
Total costs	125.1	136.9	165.9	181.9	210.0	208.8	193.2	177.7
Revenue for CO <sub>2</sub> -EOR	-	-167.9	-139.7	-8.2	-1.7	-2.7	-2.0	-1.6
Pipeline Network in 1000 km	-	28.2	28.2	28.2	28.2	28.2	28.2	28.2
<b>Capture in Mt CO<sub>2</sub> per year</b>								
Cement	0.0	3.9	3.9	0.0	0.0	0.0	0.0	0.4
Steel	0.0	110.1	97.1	5.7	1.2	10.7	10.1	9.5
Refinery	0.0	13.3	1.3	0.0	0.0	0.0	0.0	0.0
Coal	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum Power Sector	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum Industry	0.0	127.2	102.3	5.7	1.2	10.7	10.2	9.9
Total	0.0	130.2	102.3	5.7	1.2	10.7	10.2	9.9
<b>Storage in Mt CO<sub>2</sub> per year</b>								
Hydrocarbon field (w/o EOR)	0.0	0.0	0.0	0.0	0.0	8.9	8.9	8.9
EOR Field	0.0	130.2	102.3	5.7	1.2	1.8	1.3	1.0
Saline Aquifer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% of Storage used	0%	2%	3%	3%	3%	3%	3%	3%
% of EOR Storage used	0%	53%	95%	97%	98%	99%	99%	100%
<b>Cross-border CO<sub>2</sub> flows</b>								
From	To							
NL	BE	-	0.2	0.2	-	-	-	-
NL	DE	-	0.1	0.1	0.1	0.1	0.1	0.1
NL	DK	-	38.7	26.9	1.2	0.3	0.5	0.3
BE	UK	-	9.6	9.6	-	-	-	-
BE	NL	-	28.6	16.8	-	-	-	-
DE	NL	-	4.8	4.8	-	-	0.0	0.0
DE	BE	-	17.6	13.5	-	-	-	-
DE	NO	-	22.0	21.4	0.8	0.2	0.4	0.2
NO	UK	-	25.3	19.9	0.9	0.3	0.3	0.2
SE	NO	-	7.4	2.8	0.1	-	-	-
FR	BE	-	8.8	1.2	-	-	-	-
FR	DE	-	1.9	1.8	-	-	-	-
FR	NO	-	20.1	20.1	-	-	-	-

Table 13: Low CO<sub>2</sub> - Medium Oil Price Scenario: Summary of key model outputs.

## Results of Low CO<sub>2</sub> - Low Oil Price Scenario

	2015	2020	2025	2030	2035	2040	2045	2050
<b>Sum of costs in Bn € per period</b>								
Capture capital costs	10.3	-	-	-	-	-	-	-
Capture variable costs	-	18.3	17.3	2.0	0.4	1.6	1.4	1.3
Expenditures for CO <sub>2</sub> certificates	77.2	81.6	122.5	178.4	208.4	206.4	191.2	175.8
Transport capital costs	17.3	-	0.0	-	0.2	0.0	0.0	-
Transport variable costs	-	7.8	7.7	0.7	0.1	0.2	0.2	0.2
Storage capital costs	11.2	-	-	-	0.6	0.0	-	-
Storage variable costs	-	20.0	19.7	2.4	0.5	0.5	0.3	0.2
Sum of capital costs	38.9	-	0.0	-	0.9	0.0	0.0	-
sum of variable CCTS costs	-	46.1	44.8	5.1	1.1	2.3	1.8	1.7
Total costs	116.1	127.7	167.2	183.5	210.3	208.7	193.0	177.5
Revenue for CO <sub>2</sub> -EOR	-	-124.4	-122.5	-14.7	-3.2	-1.8	-0.4	-0.1
Pipeline Network in 1000 km	-	25.5	25.5	25.5	25.5	25.5	25.5	25.5
<b>Capture in Mt CO<sub>2</sub> per year</b>								
Cement	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.4
Steel	0.0	103.6	103.0	12.8	2.8	10.9	9.8	9.2
Refinery	0.0	2.9	1.9	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum Power Sector	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum Industry	0.0	108.1	106.5	12.8	2.8	11.0	9.8	9.6
Total	0.0	108.1	106.5	12.8	2.8	11.0	9.8	9.6
<b>Storage in Mt CO<sub>2</sub> per year</b>								
Hydrocarbon field (w/o EOR)	0.0	0.0	0.0	0.0	0.0	9.3	9.4	9.4
EOR Field	0.0	108.1	106.5	12.8	2.8	1.5	0.3	0.1
Saline Aquifer	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
% of Storage used	0%	1%	3%	3%	3%	3%	3%	3%
% of EOR Storage used	0%	47%	92%	98%	99%	100%	100%	100%
<b>Cross-border CO<sub>2</sub> flows</b>								
From	To							
NL	BE	-	0.2	0.2	-	-	-	-
NL	DE	-	0.1	0.1	0.1	0.1	0.1	0.1
NL	DK	-	31.2	31.2	1.9	0.6	0.5	0.0
BE	UK	-	12.4	11.8	-	-	-	-
BE	NL	-	19.4	19.4	-	-	-	-
DE	NL	-	6.4	6.4	-	-	0.0	0.0
DE	BE	-	17.6	17.6	-	-	-	-
DE	NO	-	20.4	20.4	2.7	0.5	0.3	0.1
NO	UK	-	21.2	20.9	1.9	0.8	0.2	0.1
SE	NO	-	3.2	3.2	0.5	-	-	-
FR	BE	-	2.3	1.8	-	-	-	-
FR	DE	-	1.9	1.9	-	-	-	-
FR	NO	-	20.1	20.1	-	-	-	-

Table 14: Low CO<sub>2</sub> - Low Oil Price Scenario: Summary of key model outputs.

## Results of High CO<sub>2</sub> - Medium Oil Price Scenario

	2015	2020	2025	2030	2035	2040	2045	2050
<b>Sum of costs in Bn € per period</b>								
Capture capital costs	16.5	-	-	-	10.3	67.4	-	-
Capture variable costs	-	26.8	15.0	1.1	19.3	31.9	159.7	142.7
Expenditures for CO <sub>2</sub> certificates	99.2	115.6	179.6	257.0	301.4	296.0	68.2	92.6
Transport capital costs	22.5	-	0.1	3.8	5.1	56.5	0.2	0.6
Transport variable costs	-	9.9	6.5	0.3	4.3	6.5	29.9	28.4
Storage capital costs	14.9	-	0.2	9.1	5.7	36.4	-	-
Storage variable costs	-	26.5	17.1	0.9	2.6	4.1	13.8	12.3
Sum of capital costs	53.9	-	0.2	12.9	21.2	160.3	0.2	0.6
sum of variable CCTS costs	-	63.2	38.6	2.3	26.2	42.5	203.3	183.5
Total costs	153.1	178.8	218.4	272.2	348.8	498.8	271.6	276.6
Revenue for CO <sub>2</sub> -EOR	-	-184.5	-126.3	-6.4	-0.5	-1.8	-3.2	-
Pipeline Network in 1000 km	-	30.4	30.4	30.4	31.5	40.6	56.2	56.2
<b>Capture in Mt CO<sub>2</sub> per year</b>								
Cement	0.0	12.2	11.7	0.0	12.2	59.9	78.6	78.6
Steel	0.0	110.2	80.9	7.2	110.2	110.2	110.2	110.2
Refinery	0.0	15.0	0.0	0.0	2.8	24.1	105.8	105.8
Coal	0.0	5.6	0.0	0.0	0.0	0.5	245.7	229.4
Gas	0.0	0.0	0.0	0.0	0.0	0.0	130.3	93.2
Sum Power Sector	0.0	5.6	0.0	0.0	0.0	0.5	376.0	322.7
Sum Industry	0.0	137.4	92.5	7.2	125.1	194.1	294.6	294.6
Total	0.0	143.0	92.5	7.2	125.1	194.7	670.6	617.2
<b>Storage in Mt CO<sub>2</sub> per year</b>								
Hydrocarbon field (w/o EOR)	0.0	0.0	0.0	2.7	85.7	103.4	383.6	348.5
EOR Field	0.0	143.0	92.5	4.5	0.4	1.2	2.1	0.0
Saline Aquifer	0.0	0.0	0.0	0.0	39.1	90.0	285.0	268.7
% of Storage used	0%	2%	3%	3%	5%	7%	15%	23%
% of EOR Storage used	0%	59%	97%	98%	98%	99%	100%	100%
<b>Cross-border CO<sub>2</sub> flows</b>								
From	To							
NL	UK	-	-	-	-	-	9.3	11.0
NL	BE	-	0.2	0.2	-	0.2	74.8	78.2
NL	DE	-	0.1	0.1	0.1	0.1	10.0	10.0
NL	DK	-	40.2	22.1	1.1	0.2	0.6	-
BE	UK	-	3.3	3.3	-	10.2	264.1	263.6
BE	NL	-	33.0	14.9	-	26.1	53.5	31.3
BE	FR	-	-	-	-	-	0.4	0.4
IE	UK	-	1.6	1.6	-	1.4	5.4	3.6
DE	NL	-	1.9	1.9	-	1.9	28.0	25.3
DE	BE	-	17.6	6.4	-	17.6	144.4	121.7
DE	NO	-	25.0	19.1	0.7	2.3	117.7	117.3
DE	FR	-	-	-	-	-	1.3	1.3
NO	UK	-	28.3	17.4	0.8	0.0	28.3	27.4
SE	NO	-	8.6	0.5	-	3.8	11.2	11.2
FR	BE	-	6.8	-	-	6.8	67.0	65.3
FR	DE	-	1.9	1.8	-	1.9	6.6	6.6
FR	NO	-	22.1	19.8	-	22.1	24.5	24.5

Table 15: High CO<sub>2</sub> - Medium Oil Price Scenario: Summary of key model outputs.

## Results of Low CO<sub>2</sub> - Low Oil Price Scenario

	2015	2020	2025	2030	2035	2040	2045	2050
<b>Sum of costs in Bn € per period</b>								
Capture capital costs	12.0	-	-	-	12.2	68.3	-	-
Capture variable costs	-	20.3	17.0	1.4	17.9	30.0	159.7	142.7
Expenditures for CO <sub>2</sub> certificates	99.2	118.7	177.1	256.5	304.7	299.4	68.2	92.6
Transport capital costs	19.1	0.0	0.0	3.0	6.1	56.6	0.2	0.5
Transport variable costs	-	8.6	7.6	0.4	4.0	6.3	29.5	28.1
Storage capital costs	12.3	-	0.1	8.6	5.9	36.9	-	-
Storage variable costs	-	21.9	19.5	1.4	2.5	3.8	13.9	12.3
Sum of capital costs	43.4	0.0	0.1	11.6	24.2	161.8	0.2	0.5
sum of variable CCTS costs	-	50.8	44.2	3.2	24.3	40.1	203.1	183.1
Total costs	142.7	169.5	221.4	271.3	353.3	501.3	271.5	276.2
Revenue for CO <sub>2</sub> -EOR	-	-136.2	-121.4	-8.6	-0.9	-0.4	-3.3	-
Pipeline Network in 1000 km	-	28.0	28.0	28.0	31.2	37.9	56.2	56.2
<b>Capture in Mt CO<sub>2</sub> per year</b>								
Cement	0.0	5.7	5.7	0.0	5.7	59.9	78.6	78.6
Steel	0.0	108.0	99.9	9.1	108.0	110.2	110.2	110.2
Refinery	0.0	4.2	0.0	0.0	2.8	17.0	105.8	105.8
Coal	0.0	0.5	0.0	0.0	0.0	0.5	245.7	229.4
Gas	0.0	0.0	0.0	0.0	0.0	0.0	130.3	93.2
Sum Power Sector	0.0	0.5	0.0	0.0	0.0	0.5	376.0	322.7
Sum Industry	0.0	117.9	105.6	9.1	116.5	187.0	294.6	294.6
Total	0.0	118.4	105.6	9.1	116.5	187.6	670.6	617.2
<b>Storage in Mt CO<sub>2</sub> per year</b>								
Hydrocarbon field (w/o EOR)	0.0	0.0	0.0	1.5	76.5	99.4	379.1	344.7
EOR Field	0.0	118.4	105.6	7.5	0.8	0.4	2.9	0.0
Saline Aquifer	0.0	0.0	0.0	0.0	39.2	87.8	288.6	272.6
% of Storage used	0%	1%	3%	3%	4%	7%	15%	23%
% of EOR Storage used	0%	50%	95%	98%	99%	99%	100%	100%
<b>Cross-border CO<sub>2</sub> flows</b>								
From	To							
NL	UK	-	-	-	-	-	7.2	8.9
NL	BE	-	0.2	0.2	-	0.2	14.0	77.0
NL	DE	-	0.1	0.1	0.1	0.1	0.1	10.0
NL	DK	-	34.0	28.5	1.4	0.4	0.2	0.9
BE	UK	-	11.8	10.8	-	12.4	42.9	266.0
BE	NL	-	24.4	18.9	-	23.8	23.0	53.8
BE	FR	-	-	-	-	-	0.4	0.4
IE	UK	-	-	-	-	-	1.7	5.4
DE	NL	-	4.3	4.3	-	4.3	18.1	28.0
DE	BE	-	17.6	16.7	-	17.6	22.8	144.4
DE	NO	-	22.5	21.4	1.6	3.0	3.0	117.2
DE	FR	-	-	-	-	-	-	1.3
NO	UK	-	23.2	20.6	1.0	0.1	-	23.2
SE	NO	-	3.2	2.8	0.2	3.2	3.8	11.2
FR	BE	-	6.8	1.2	-	6.8	11.4	67.0
FR	DE	-	1.9	1.8	-	1.9	1.9	6.6
FR	NO	-	20.1	20.1	-	20.1	22.1	24.5

Table 16: High CO<sub>2</sub> - Low Oil Price Scenario: Summary of key model outputs.



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