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## European Scenarios of CO<sub>2</sub> Infrastructure Investment until 2050 – CO<sub>2</sub>-Enhanced Oil Recovery Keeps the Mirage Alive

Pao-Yu Oei<sup>\*</sup> and Roman Mendelevitch<sup>†</sup>

### Abstract

Based on a critical review of the current state of the Carbon Capture, Transport and Storage (CCTS) technology, this paper analyzes the layout and costs of a potential CO<sub>2</sub> infrastructure in Europe at the horizon of 2050. We apply the mixed-integer model CCTS-Mod to compute a CCTS infrastructure network for Europe, examining the effects of different CO<sub>2</sub> price paths with different regional focuses. Scenarios assuming low CO<sub>2</sub> certificate prices lead to hardly any CCTS development in Europe. The iron and steel sector starts deployment as soon as the CO<sub>2</sub> certificate price exceeds 50 €/tCO<sub>2</sub>. The cement sector starts investing at a threshold of 75 €/tCO<sub>2</sub>, followed by the electricity sector when prices exceed 100 €/tCO<sub>2</sub>. Results on the degree of deployment of CCTS are found to be more sensitive to variable cost of CO<sub>2</sub> capture than to investment costs. Additional revenues from using the CO<sub>2</sub> for enhanced oil recovery (CO<sub>2</sub>-EOR) in the North Sea would lead to an earlier adoption of CCTS, independent of the CO<sub>2</sub> certificate price; this case may become especially relevant for the UK, Norway and the Netherlands. On the downside, scattered CCTS deployment increases unit cost of transport and storage infrastructure by 30% and more.

Keywords: CCS, CCTS, CO<sub>2</sub> emissions, scenario analysis, infrastructure, modeling, EOR

JEL-code: Q40, Q48, Q50, Q52, Q58

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## 1 INTRODUCTION

Carbon Capture, Transport and Storage (CCTS) was originally seen as a central element for decarbonized electricity systems, worldwide (e.g. IEA, 2010). The International Energy Agency (IEA) consequently underlined its importance with a 20% contribution to achieving emission reduction goals and 40% cost increase for decarbonization in its absence (IEA, 2012). Estimates for the European energy system assumed 77 (IEA, 2012) to 108 GW (EC, 2011) of power generation capacity to be equipped with CCTS and a CO<sub>2</sub> transport network of over 20,000 km by 2050 (JRC, 2011). The reality, however, is in great contrast to these expectations. Not a single full-scale CCTS project with long-term geological storage has yet been realized in the world (GCCSI, 2014). At the same time, CO<sub>2</sub> transport infrastructure projects have been removed from the list of critical infrastructure projects of the EU (EC, 2013a). Furthermore, the London Protocol still prohibits the movement of CO<sub>2</sub> across marine borders for the purposes of geological storage (GCCSI, 2014). Facing these adverse developments, academia as well as technical reports became more balanced or even critical with respect to CCTS deployment (Hirschhausen et al., 2012a).

The gridlock in the deployment of CCTS can be partly explained by the low level of the EU Emissions Trading System (ETS) CO<sub>2</sub> price which remained in the range of three to eight €/tCO<sub>2</sub> since the start of the third trading period in 2013. Such low prices – with little hope for a significant rise in the coming years (Hu et al., 2015) – give insufficient incentives for investment into mitigation technologies such as CCTS. Even additional financial schemes such as the European Energy Program for Recovery (EEPR) proved unsuccessful in enabling projects (GCCSI, 2014). The New Entrance Reserve (NER300) program, originally designed to provide up to 9 €bn of funds to renewables and CCTS projects, ended up with a budget of only 1.5 €bn as its revenue was based on the sales of 300 million CO<sub>2</sub> allowances. As a consequence, none of the 12 CCTS projects that applied for funding in the first round were supported (Lupion and Herzog, 2013). In July 2014 the second round of the NER300 granted 300 €bn to the UK White Rose CCS Project. Meanwhile, the original project timeline was pushed back by two years, aiming at completion only in 2020 (EC, 2014a; Szabo, 2014). Martinez Arranz (2015) identifies various blind

spots in the EU demonstration programs, as Europe, in comparison to other regions, is a relatively resource-poor but advanced economy. He therefore recommends a stronger focus on the industrial use of CCTS as well as other non-CCTS mitigation possibilities in the power sector.

At the European level, the directive on the geological storage of CO<sub>2</sub> (so-called "CCS Directive") is the central regulatory element intended to govern the process of CCTS commercialization (EC, 2013b). However, it limits the scope of underground storage to a non-commercial size and is not sufficient for large scale projects (Triple EEE Consulting, 2014). Although focusing on the storage part of the technology chain, the Directive also requires "CCTS readiness" for new fossil generation capacities. Lacking a clear definition of this "readiness", the Directive leaves space for interpretation which was exploited by member states. A review process of the Directive in 2014 highlighted the need for running CCTS demonstration projects in Europe. In particular, it criticizes the lack of progress of CCTS for industrial applications such as steel or cement facilities, which account for one quarter of the world's energy-related CO<sub>2</sub> emissions. One possible option that many stakeholders requested during the review process was a successor NER300 scheme from 2020 onwards to support future projects (Triple EEE Consulting et al., 2015).

Complementary to price incentives, in some countries CCTS is promoted via climate-oriented regulation or in combination with enhanced oil recovery (CO<sub>2</sub>-EOR) projects. The introduction of emissions performance standards (EPS) in the UK, Canada and the US restrict the annual amount of CO<sub>2</sub> emissions per installed unit of generation capacity and thereby the operation of new coal power plants without CO<sub>2</sub> capture<sup>3</sup>. Using the captured CO<sub>2</sub> for EOR purposes contradicts the idea of long-term geological storage but significantly improves the economics of a CCTS project. Successful projects like Boundary Dam in Saskatchewan, Canada (in operation since October 2014) as well as the majority of upcoming projects in 2016-17 (e.g. Kemper County Energy Facility and Petra Nova Carbon Capture Project in the US) are associated with CO<sub>2</sub>-EOR. Only little progress, however, is visible in the EU as

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<sup>3</sup> The UK has introduced an Electricity Market Reform (The Parliament of Great Britain, 2013), where one of the four pillars builds on EPS benchmarked against gas-fired electricity generation; similarly, the US (EPA, 2012, final rule pending for submission to the federal register since 05.08.2015) and Canada (Parliament of Canada, 2012) have introduced EPS for new electricity generation units.

only a few riparian states of the North Sea have an option for CO<sub>2</sub>-EOR application. Nevertheless, the EU framework for climate and energy still aims at a commercial CCTS deployment by the middle of the next decade (EC, 2014b).

In this paper we present model analysis and interpretation on the potential role of CCTS to support the EU energy system transition to meet emissions reductions goals that are consistent with an international goal of staying below 2°C of global warming. Our hypothesis is that CCTS – contrary to the dominant belief until recently – will at best be a niche technology applied in regions with highly conducive conditions, e.g. parts of the North Sea, but that due to its cost disadvantage and recent setbacks in many EU countries, it will not contribute significantly to overall EU decarbonization. The next section provides a non-technical description of our CCTS-Mod; a multi-period, scalable, mixed integer framework calculating beneficial investments in the CO<sub>2</sub>-chain (capture, transport, storage). Section 3 presents the results of the European-wide results. We find no role for CCTS in the 40% mitigation scenarios; in the 80% mitigation scenarios, some CO<sub>2</sub>-intensive industries might start to abate, followed by the energy sector at a high CO<sub>2</sub> price (above 100 €/tCO<sub>2</sub>). We consider this scenario unlikely, though, because most of the countries involved have already given up CCTS as a mitigation option, e.g. Germany, Poland, France, and Belgium. Section 4 then focuses on an alternative driver for CO<sub>2</sub>-abatement through CO<sub>2</sub>-EOR. We find that for North Sea riparian countries that have not given up on CO<sub>2</sub>-capture, mainly the UK and Norway, the use of CO<sub>2</sub> for EOR might be an economic option, depending on the oil price and the price of CO<sub>2</sub> certificates. Also, the speed and extend of the deployment is highly dependent on assumptions for initial technology costs and learning effects. Section 5 concludes, analyzing the chances for a regional vs. European-wide CCTS application depending on the availability of CO<sub>2</sub>-EOR and other storage potentials.

## **2 MODEL, DATA, AND ASSUMPTIONS**

### **2.1 The Model CCTS-Mod**

For our numerical analysis we use the “CCTS-Mod” (Oei et al., 2014). The model is a multi-period, scalable, mixed integer model coded in GAMS (General Algebraic Modeling Software) and solved

with a CPLEX solver. For each power plant or industrial facility covered in our input database (see section 2.2) an omniscient planner decides on whether to invest into a CCTS chain or to buy CO<sub>2</sub> certificates instead. The model decides in favor of CCTS whenever future costs of CO<sub>2</sub> certificates exceed the total costs of CO<sub>2</sub> capture, transport, and storage. In this case, investments into a capture unit facing respective capital costs have to be made. It takes five years after the investment decision before the capture unit becomes operational. Whenever the facility is actually used to capture the CO<sub>2</sub> variable costs are induced. The capture rate is capped at 90%. CO<sub>2</sub> capture has to be balanced with CO<sub>2</sub> transport and storage. Again, respective infrastructure investments have to be made taking into account a construction period of five years. Capital costs for transport cover right of way (ROW) costs and other investment cost parameters. If a new pipeline is constructed along a route that is already developed, ROW costs do not apply. This ensures that transportation routes are bundled in corridors, which is consistent with current practice for laying pipelines (e.g. for natural gas). The construction of a pipeline is a binary decision with discrete pipeline diameters and associated throughput volumes. CO<sub>2</sub> storage is again subject to a five year construction period and has associated variable and capital costs.

A refined version of the model which is used for the model runs of this paper includes the option to use captured CO<sub>2</sub> for enhanced oil recovery. CO<sub>2</sub>-EOR storage is associated with additional investment and variable costs for equipment and operation respectively, but generates revenues from oil recovered with each ton of CO<sub>2</sub> stored. The simplified decision path of the CCTS-Mod is illustrated in Figure 1. A more detailed model description (though without the option of CO<sub>2</sub>-EOR) can be found in Oei et al. (2014). The model is well-based in the literature on CCTS infrastructure models, building on models developed by Middleton and Bielicki (2009) and Morbee et al. (2012).

Thus, the main drivers of the model are location and volumes of CO<sub>2</sub> emissions, storage capacities, investment and variable costs of each stage of the CCTS technology chain, and the assumptions on future CO<sub>2</sub> certificate and oil prices. Several caveats are in place regarding the model: First, the cost minimizing approach does underestimate the real costs of the CCTS technology, as we assume perfect foresight as well as a vertically integrated CCTS chain. Second, the model assumes the existence of certain technologies that have not been proven to work in practice on a larger scale. The “cost” estimates

for CO<sub>2</sub> capture and storage are especially uncertain, and most likely highly underestimated. The model also does not take into account the transaction costs of bringing the immature technology to implementation, to build the infrastructure or to develop the storage sites; nor do we include costs due to rising public opposition.

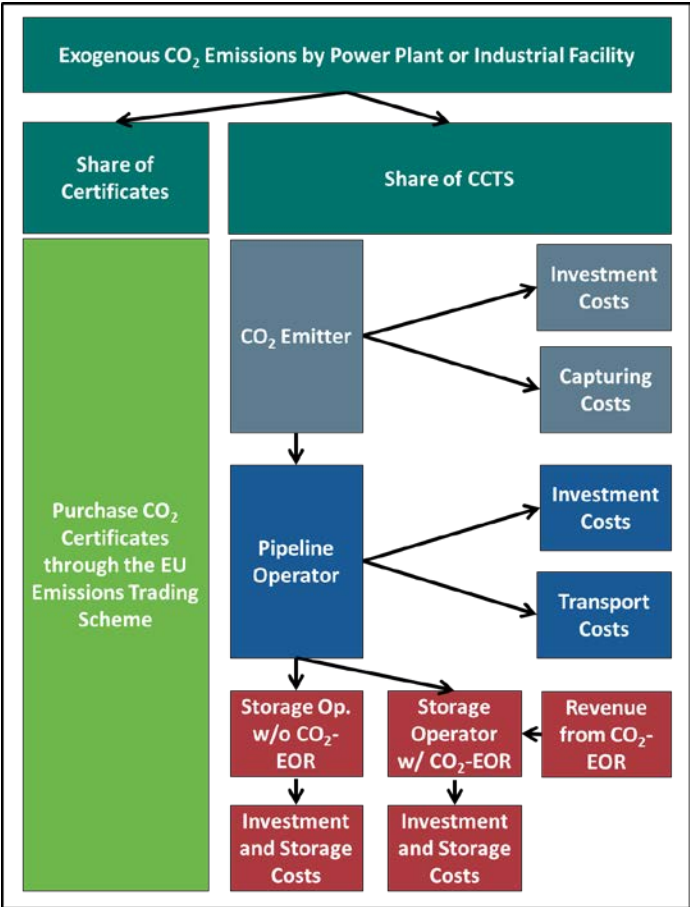


Figure 1: Decision Tree of the Model CCTS-Mod.

**2.2 Data**

Data was collected for the period from 2015 to 2055.<sup>4</sup> A detailed description of the cost data can be found in Mendelevitch (2014). The scope of this study includes all members of the EU as well as Switzerland and Norway, and their respective Exclusive Economic Zones (EEZs). Data on location and

<sup>4</sup> Note that model results for 2055 will not be interpreted. This last period is introduced to include an additional payback period and to allow for investment in 2050.

emission volumes of refineries, steel and cement production facilities as well as coal- and gas-fired power plants is taken from a database developed earlier in Oei, Herold, & Mendelevitch (2014). The database assumes an economic lifetime of 40 years for gas-fired and 50 years for coal-fired power plants. Power generation facilities are supposed to be shut down and not replaced after the economic lifetime is reached while industrial plants are assumed to be replaced by a facility with similar characteristics. The same database was used for location and capacities of potential storage in depleted hydrocarbon fields and saline aquifers. Data on location and volumes of CO<sub>2</sub>-EOR storage sites is taken from Mendelevitch (2014).

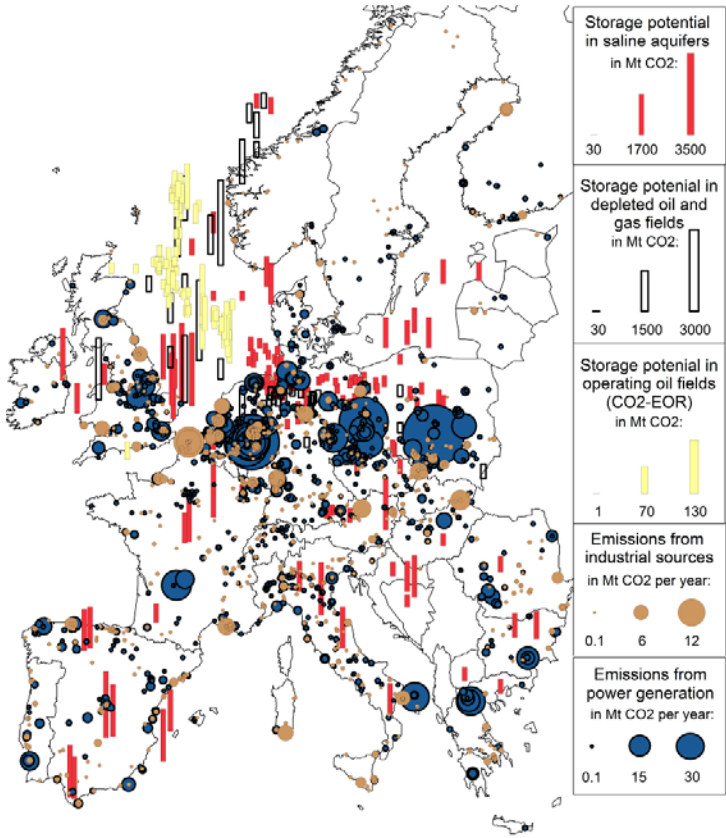


Figure 2: Distribution of CO<sub>2</sub> emission sources and potential storage sites by type and volume in the CCTS-Mod data set.

Source: Own illustration based on Oei, Herold, & Mendelevitch (2014) and Mendelevitch (2014).

Figure 2 illustrates the distribution of emission sources and their respective emission volumes for 2010 as well as the distribution of storage sites by type and their respective capacities. It visualizes the fact



that emission sources and storage sites are not equally spread across Europe. While the largest emission sources are located in the Rhine Area, the largest storage capacities can be found offshore in the UK and Norwegian EEZs.<sup>5</sup> Denmark, UK and Norway are the only countries that have potential for CO<sub>2</sub>-EOR in their parts of the North Sea. Strong opposition in several European countries has formed against onshore CO<sub>2</sub>-storage. All scenarios in this paper therefore only include the option of storing the CO<sub>2</sub> in offshore fields.

### 2.3 Assumptions for all Scenarios

Two key parameters drive the results of our model runs: On the one hand CCTS deployment is triggered by the CO<sub>2</sub> certificate price path which governs the profitability of the CCTS technology in comparison to balancing CO<sub>2</sub> emissions with purchased CO<sub>2</sub> certificates. If in the long run, anticipated prices are higher than the costs of using the technology chain, then CCTS is employed. We use two possible price pathways generated by the PRIMES model (EC, 2013c) which represent the outcomes of two sets of scenarios for climate change mitigation policy up to 2050 (see Table 1). The 40% scenarios include the EU 2020 targets as well as a 40% greenhouse gas (GHG) reduction by 2050 compared to 1990. The 80% scenarios are more ambitious including an 80% GHG reduction by 2050. All scenarios allow for no emission trading across macro regions (but trade within macro regions, e.g. within the EU through a cap and trade system). They include moderate assumptions on efficiency gains and availability of nuclear and renewable energies (see Holz and Hirschhausen (2013) and Knopf et al. (2013) for a more detailed description of the underlying assumptions).

Table 1: CO<sub>2</sub> certificate price path in the different scenarios.

	<i>Scenario</i>	<i>2015</i>	<i>2020</i>	<i>2025</i>	<i>2030</i>	<i>2035</i>	<i>2040</i>	<i>2045</i>	<i>2050</i>
Certificate price in €tCO <sub>2</sub>	40%	14	17	27	37	45	52	52	52
	80%	18	25	39	53	75	97	183	270

Source: Knopf et al. (2013).

<sup>5</sup> The estimates for possible storage locations are based on studies which mostly offer data on a 50 x 50 km grid. Some of these formations, however, consist of several smaller neighboring aquifers. The exploration of very small reservoirs is uneconomical, given a bad ratio of investment costs and exploitable storage capacity. The overall storage potential of Europe is thus overestimated in this paper due to the lack of more detailed information.

The availability of storage capacity is the other 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. The Global CCS Institute has performed a comprehensive assessment of CO<sub>2</sub> storage readiness on a country level and come to the conclusion that Norway is the only European country currently ready for a wide-scale CO<sub>2</sub> storage deployment (GCCSI, 2015). Germany, the Netherlands and UK are the only countries that are at least ranked advanced. The report revealed a high correlation between a country's ranking and the existence of an advanced hydrocarbon industry, and its dependence of fossil resources. Following long debates, onshore storage was excluded as a storage option in Germany (Hirschhausen et al., 2012b; Schumann et al., 2014), Denmark (Brøndum Nielsen, 2011), the UK and Netherlands (GCCSI, 2012). Analogous developments are conceivable for other countries, leaving offshore storage as the only remaining storage option in Europe. This can also be seen in the fact that none of the Europe-based large-scale integrated projects CCTS projects listed in the Global CCS Institute database include onshore CO<sub>2</sub> storage (GCCSI, 2014). Therefore, in all presented scenarios onshore storage capacity is not available, which reduces total available storage capacity from 94 GtCO<sub>2</sub> to 50 GtCO<sub>2</sub> in the European-wide scenarios and from 56 GtCO<sub>2</sub> to 42 GtCO<sub>2</sub> for the scenarios which focus on the North Sea region. As a consequence, France and Belgium lose most of their domestic storage potential. Despite a number of minor storage resources (1.2 GtCO<sub>2</sub>) in saline aquifers in the German North Sea, the situation in Germany is similar.

The resulting scenarios shown in Table 2 differ in their respective CO<sub>2</sub> price path, the availability of storage potential (offshore with vs. without CO<sub>2</sub>-EOR) and geographical coverage (European-wide vs. the North Sea region vs. selected countries). Section 3 describes the European scenarios (*EU\_40%* and *EU\_80%*) while section 4 further analyzes regional scenarios (*NorthSea\_40%*, *NorthSea\_80%* and *DNNU\_80%*).

Table 2: List of scenario assumptions

<i>Scenario</i>	<i>Coverage</i>	<i>CO<sub>2</sub> price in 2050</i>	<i>Storage availability</i>
<i>EU_40%</i>	Europe	52 €/t	Offshore only
<i>EU_80%</i>	Europe	270 €/t	Offshore only
<i>NorthSea_40%</i>	North Sea region	52 €/t	Offshore only + CO <sub>2</sub> -EOR
<i>NorthSea_80%</i>	North Sea region	270 €/t	Offshore only + CO <sub>2</sub> -EOR
<i>DNNU_80%</i>	DK, NL, NO, UK	270 €/t	Offshore only + CO <sub>2</sub> -EOR

### 3 RESULTS OF THE EUROPEAN-WIDE SCENARIO ANALYSIS

#### 3.1 EU\_40% Scenario

CCTS starts being deployed from the year 2035 onwards when the CO<sub>2</sub> certificate price passes the 40 €/tCO<sub>2</sub> threshold. Nevertheless only a very small annual amount of around 1 MtCO<sub>2</sub> is being captured and stored in offshore hydrocarbon fields as well as saline aquifers. Hydrocarbon fields are the cheapest storage option when excluding CO<sub>2</sub>-EOR, but are not available at all locations. Four iron and steel factories in Norway and Estonia are the only emitters that invest in capture technology, benefiting from the lower variable and fixed costs assumed for this industry. The investing factories are located at the coast which leads to lower transport costs than for other industrial facilities. The overall costs sum up to 0.2 €bn of investment costs and an additional 0.4 €bn of variable costs until 2050.

#### 3.2 EU\_80% Scenario

The assumptions of the CO<sub>2</sub> price in the *EU\_80%* scenario are much higher than in the *EU\_40%* scenario. The price increases gradually until a stronger rise kicks off in 2030, resulting in its final value of 270 €/tCO<sub>2</sub> in 2050. CCTS deployment starts once the CO<sub>2</sub> price exceeds 40 €/tCO<sub>2</sub> which happens in the year 2030 due to the steep path increase. The first investments into the CCTS technology can be seen in the previous years (2020-2025). The iron and steel sector is – similar to previous modeling runs in Oei et al. (2014) – again the first mover until some cement works start capturing CO<sub>2</sub> from 2035 onwards (see Figure 3). At that point a certificate price of 75 €/tCO<sub>2</sub> is reached and a total of 300 MtCO<sub>2</sub> is annually stored in offshore hydrocarbon fields and saline aquifers. CCTS becomes economical for power plants and

refineries as soon as the price exceeds 100 €/tCO<sub>2</sub> in the year 2040. Still rising prices above 180 €/tCO<sub>2</sub> in 2045 lead to additional economic incentives for more distant power plants to invest in further CCTS deployment. Annual captured emissions sum up to more than 1 billion t CO<sub>2</sub> from 2040 to 2045. These emissions are then transported via a pipeline network of 44,800 km to different storage locations. Total captured emissions start decreasing after 2045 due to the phase out of several older power plants. 12.2 GtCO<sub>2</sub> is stored in offshore storage sites until 2050. 55% of these emissions originate from industrial sources.

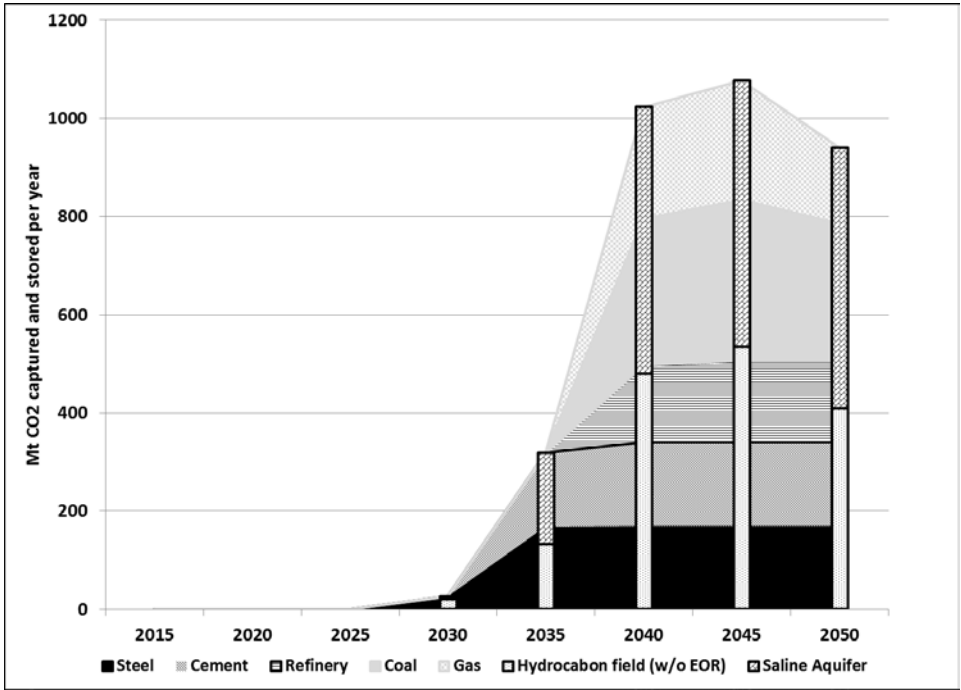


Figure 3: Captured CO<sub>2</sub> emissions by source and storage type over time in the EU\_80% scenario.

The capturing costs have the highest share (60-70%) in variable as well as fixed costs of the CCTS chain (see Figure 4). The infrastructure costs of storage comprise around 30% of the total investment costs, but have relatively small share of total variable costs of 10%. Transport costs depend very much on the location of each facility and range around 10-15% in variable and fixed costs. This step of the CCTS technology chain is also the driver making CCTS a more beneficial option for facilities closer to possible storage sites. This can be clearly seen as the first movers are mostly located near the North Sea where the

highest offshore storage potential can be found. The overall investment costs until 2050 exceed 300 €bn with an additional 730 €bn of variable costs.

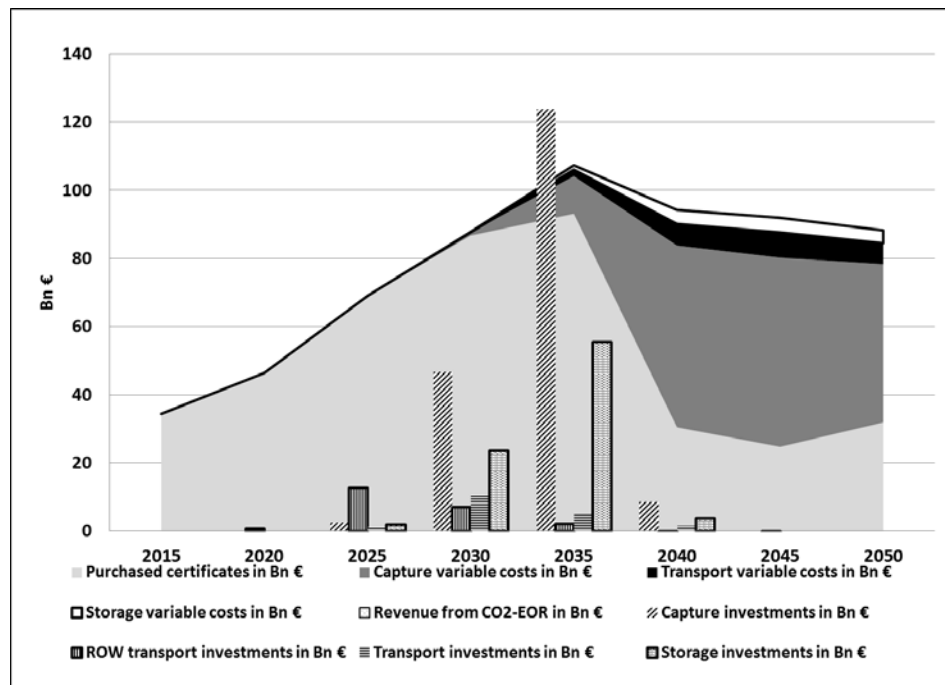


Figure 4: Cost distribution over the whole timespan in the *EU\_80%* scenario in €bn.

### 3.3 Sensitivity to Investment and Variable Costs

Many cost studies of the CCTS technology chain name the capture stage as most cost intensive for both investment and variable costs (e.g. The Crown Estate et al., 2013). To assess the sensitivity of the resulting CCTS infrastructure to these cost parameters we simulated four additional scenarios: two where we double the capital costs (*Inv\_200%*) and variable costs (*Var\_200%*) respectively, one with double capital and variable costs (*Inv&Var\_200%*), and one with variable and capital costs both increased by 50% (*Inv&Var\_150%*).<sup>6</sup> Table 3 provides the input values for the sensitivity analysis and reference values from the CCTS-Mod model and the PRIMES model (EC, 2013c) for comparison. The capital costs used for the base run are 25-30% below the input values in the PRIMES model. For variable costs no values for comparison were available.

<sup>6</sup> The given costs only include the additional variable and fixed costs for equipping a power plant or industrial facility with a capturing unit compared to a facility without a capturing unit.

Table 3: Input parameters for sensitivity analysis, and reference values for comparison.

<i>Input Parameter</i>	<i>Variation</i>	2015	2020	2020	2030	2035	2040	2045	2050
<i>Capital cost in €/tCO<sub>2y</sub></i>	<i>Base Case</i> <sup>7</sup>	175	175	162	149	138	127	118	108
	<i>Inv&amp;Var_150%</i>	263	263	243	224	207	191	177	162
	<i>Inv_200%</i>	350	350	324	298	276	254	236	216
	<i>PRIMES</i> <sup>8</sup>		211		202				153
<i>Variable cost in €/tCO<sub>2</sub></i>	<i>Base Case</i> <sup>7</sup>	64	64	63	62	61	60	59	58
	<i>Inv&amp;Var_150%</i>	96	96	95	93	92	90	89	87
	<i>Var_200%</i>	128	128	126	124	122	120	118	116

Source: EC (2013c) and Mendelevitch (2014).

In all sensitivity runs the increase in costs has led to a significant delay in the first deployment of the CCTS technology. Figure 5 (left side) shows that while in the base run CCTS is first introduced in 2030, in the *Inv\_200%* and *Inv&Var\_150%* scenario the technology is first used in 2035, and only in 2040 in the other two scenarios. The figure also illustrates the sensitivity of total costs and length of the pipeline network until 2050. For all sensitivity runs cost figures are 5-25% higher than in the base case, showing an increasing sensitivity over the model horizon due to the accumulation of higher variable costs. Figures on CO<sub>2</sub> capture, storage and pipeline network are lower for the sensitivity runs than for the base case, with the gap narrowing between 2040 and 2050 (see Figure 5, right side). For the two scenarios *Inv\_200%* and *Inv&Var\_150%* the overall impact on key results like capture, and storage amounts and length of pipeline infrastructure is at most 10% or less. By contrast, doubling the variable capture costs has a strong impact on the length of the pipeline network with a decrease of over 35% compared to the base case. The future development of a CCTS infrastructure is therefore more sensitive to its variable than its investment costs. However, the deployment of the CCTS technology as a whole is not very sensitive to even drastic increases in capture costs, given high CO<sub>2</sub> certificate prices in the end of the modeling horizon (270 €/tCO<sub>2</sub>) and the lack of alternative technologies, as both prevailing in this modeling framework.

<sup>7</sup> Data specification used for coal-fired power plants in (Mendelevitch, 2014)

<sup>8</sup> EC (2013); based on emission factor 0.9 tCO<sub>2</sub>/MWh, load factor 86%, reference power plant: 2100€/kW overnight capital costs

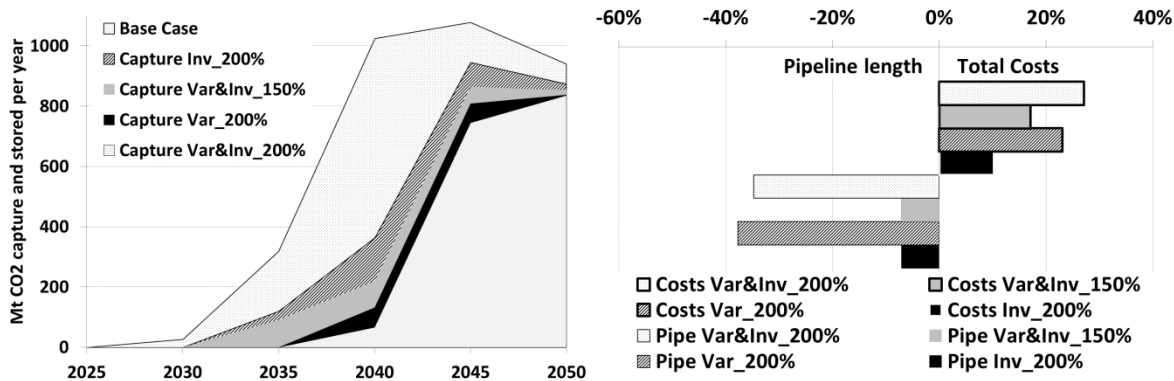


Figure 5: Sensitivity of captured amounts over the model horizon (left side), and total costs and length of the pipeline network in 2050 (right side).

### 3.4 Summary of the European-wide Scenarios

Table 4 summarizes the results of the different Europe-wide scenarios. In the *EU\_40%* scenario only four iron and steel factories in Norway and Estonia invest in the capture technology as they profit from the industry's low variable and fixed costs. These facilities additionally benefit from their ideal location close to storage sites in the North Sea, minimizing costs associated with CO<sub>2</sub> transport. CCTS cannot be considered as an abatement option for power plants if CO<sub>2</sub> prices hardly rise above 50 €/tCO<sub>2</sub>. Sensitivity analysis shows that the future development of a CCTS infrastructure is more sensitive to its variable than its investment costs.

The *EU\_80%* scenario arrives at CO<sub>2</sub> certificate prices around 250 €/tCO<sub>2</sub> in the year 2050. Under this assumption, investing in the CCTS technology is cost-efficient for all emitters, with industry still being the first mover. However, from today's perspective, these modeling results seem unrealistic. Even under the assumption of one omniscient planner, a CO<sub>2</sub> pipeline network of at least 45,000 km covering great parts of Europe would be needed, with overall system costs of 800-1,000 €bn. The construction of such a huge new infrastructure network is highly dependent on the public acceptance, especially in densely populated regions like Europe (Gough et al., 2014). Considering the number of different parties, technology stages, insecurities regarding CO<sub>2</sub> prices, learning rates and further policy measures, one comes to the conclusion that the necessary infrastructure and investment costs would be several times

higher. This questions the fact whether CCTS may be able to fulfill its role as a bridging technology for the decarbonization of Europe. The following section 4 therefore focuses on a regional CCTS deployment around the North Sea only.

Table 4: Summary of the European-wide results.

<i>Scenario</i>	<i>Pipeline Network [tsd. km]</i>		<i>Stored Emiss. until [GtCO<sub>2</sub>]</i>		<i>Origin. from industry [%]</i>	<i>Storage left in 2050 [GtCO<sub>2</sub>]</i>	<i>CCTS invest. costs [€bn]</i>	<i>CCTS var. costs [€bn]</i>
	2030	2050	2030	2050				
	<i>EU_40%</i>	-	<1	-	0.02	100	50.0	0.2
<i>EU_80%</i>	-	45	-	12.2	55	37.9	306.6	731.2

#### 4 REGIONAL FOCUS: CO<sub>2</sub>-ENHANCED OIL RECOVERY OPTIONS IN THE NORTH SEA

The planned demonstration projects with the highest chance of realization are all close to the North Sea and are aiming for offshore storage with additional profit generated from CO<sub>2</sub>-EOR (GCCSI, 2014). The following scenarios depicted in sections 4.4 and 4.5 assess the implications of CO<sub>2</sub>-EOR for the development of a CCTS infrastructure with a focus on the North Sea Region. Several of these countries such as Germany and France are, however, unlikely to take part in any future CCTS deployment.<sup>9</sup> Different national strategies towards implementation of CCTS, instead of a joint European energy strategy, thus seem most likely at the moment. Section 4.6 therefore includes a regionally focused analysis of four European countries where a joint CCTS and CO<sub>2</sub>-EOR deployment is most likely: Denmark, the Netherlands, Norway, and the UK (DNNU). One interesting aspect analyzed in this section is whether the employment of CO<sub>2</sub>-EOR by a limited number of countries increases costs due to a lack of economies of scale during the use of CO<sub>2</sub>-EOR and later. The assumed price paths are the same as in the previous scenarios.

<sup>9</sup> This is partly due to rising public opposition (NIMBY, not in my backyard, effect) as well as different national interests (e.g. France focusing on nuclear energy, Germany on the other hand on renewable energy sources).



#### 4.1 The Role of CO<sub>2</sub> Reuse for CCTS

CO<sub>2</sub>-enhanced oil recovery (CO<sub>2</sub>-EOR) is the most mature CO<sub>2</sub> reuse technology and has been practiced since the 1980s in the U.S. and Canada (cf. GCCSI and Parsons Brinckerhoff, 2011). The application of other technologies that are currently in the commercialization phase like Bauxite residue carbonation and using CO<sub>2</sub> in methanol production 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, which is equivalent to the annual emissions of the four biggest lignite power plants in Germany. CO<sub>2</sub>-EOR in the U.S. and Canada account for the biggest share with 50 Mt per year. 80% of the CO<sub>2</sub> is currently supplied from natural CO<sub>2</sub> sources at a price in the order of 15-19 US\$/tCO<sub>2</sub>. In total, anthropogenic CO<sub>2</sub> emissions can only be offset to a few percent from current and potential future demand for CO<sub>2</sub> reuse. However, although reuse has very limited 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. The IEA (2012) is currently analyzing the role of this technology. It 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 (Kemp and Kasim, 2013; Scottish Centre for Carbon Storage, 2009) and the Norwegian continental shelf (Klokk et al., 2010), and have found substantial potential for the combination of the two technologies and associated benefits.

## 4.2 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. Mendelevitch (2014) performed an intensive literature review and presents own estimates to compile a consistent database of CO<sub>2</sub>-EOR potentials 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).

For the UK Mendelevitch (2014) finds 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 Mbbl additional oil recovery potential. For Norway he identifies seven 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 Mbbl. For Denmark the study finds 14 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 sums up to 348 MtCO<sub>2</sub> which corresponds to an additional oil recovery potential of 1054 Mbbl. Other riparian countries of the North Sea do not exhibit substantial oil resources and are therefore not included in the analysis.

## 4.3 Costs and Revenue of CO<sub>2</sub>-EOR

To assess the economics of a prospective CO<sub>2</sub>-EOR infrastructure correctly, it is crucial to accurately estimate the costs associated with it. Mendelevitch (2014) draws on various case studies on CO<sub>2</sub>-EOR projects in the North Sea to develop an inventory of the main investment and operating costs components was developed (see Table 5).

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

<i>CAPEX cost component</i>		<i>Mill. €</i>
1) Survey costs to examine the reservoir characteristics with respect to CO <sub>2</sub> -EOR		1.50
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
b) recycle installments to separate, compress and re-inject CO <sub>2</sub> .		7.1
3) Well drilling costs for new injection wells		52.5
4) Monitoring and verification facility		3% of CAPEX
<i>OPEX cost component</i>		<i>€mn/MtCO<sub>2</sub></i>
1) Facility operation		5% of CAPEX
2) Oil production		12.1
3) CO <sub>2</sub> recycling		5.2
4) CO <sub>2</sub> compression and injection		8.7
5) Monitoring and verification		0.4

Source: Mendelevitch (2014).

Based on the cost components mentioned above investment costs add up to 103.9 €/tCO<sub>2</sub> stored per year and operating costs add up to 36.8 €/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, which is consistent with estimates from OECD and IEA (2008), giving a range of 40-80 US\$ per bbl (including costs of CO<sub>2</sub> supply) for long-term oil supply from CO<sub>2</sub>-EOR.

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 refinance the capture and the transport of the CO<sub>2</sub>. DOE/IEA (2012) present a compilation of different oil price projections for the Western Texas Intermediate (WTI) crude oil price for the period up to 2035. The chosen medium oil price path represents an average of the price projections while the lower price path marks their lower bound. To provide a rough estimate of the profitability of combining CCTS with CO<sub>2</sub>-EOR, Table 6 compares cost and revenue items for a generic example. The sales price of additionally produced crude oil and the assumed CO<sub>2</sub> certificate price (as negative opportunity costs) of the respective year constitute the potential revenue side. On the costs side, investment and variable costs for each of the stages of the CCTS technology chain are included. Even for the high first-of-a-kind investment costs assumed for 2015 and 2020 the combination of the two

technologies yields considerable profit of 100 €/tCO<sub>2</sub> and higher. The two most critical assumptions are the “bbl crude oil per tCO<sub>2</sub> injected” conversion rate and assumptions on the future development of oil prices. Until now, CO<sub>2</sub>-EOR operations are only performed onshore. Employing the technology in the North Sea is associated with additional technological and therefore also financial risk which is not taken into account in this calculation.

Table 6: Cost and revenue items for the deployment of CCTS-EOR<sup>10</sup>

<i>Input Parameter</i>	<i>Variation</i>	<i>2015</i>	<i>2020</i>	<i>2030</i>	<i>2040</i>	<i>2050</i>	
<i>Crude Oil Price in</i>	<i>\$/bbl</i>	92	106	118	123	135	
	<i>€/tCO<sub>2</sub></i>	222	255	282	294	324	
<i>Certificate price (40% Scenarios)</i>	<i>€/tCO<sub>2</sub></i>	14	17	37	52	52	
<i>Subtotal: returns</i>		<i>€/tCO<sub>2</sub></i>	236	272	319	346	376
<i>Capture</i>	<i>Capital cost</i>	<i>€/tCO<sub>2y</sub></i>	175	175	149	127	108
	<i>Variable cost</i>	<i>€/tCO<sub>2</sub></i>	64	64	62	60	58
	<i>Σ</i>	<i>€/tCO<sub>2</sub></i>	75	75	72	68	65
<i>Transport</i>	<i>Capital cost</i>	<i>€/tCO<sub>2y</sub></i>	57	57	57	57	57
	<i>Variable cost</i>	<i>€/tCO<sub>2</sub></i>	5	5	5	5	5
	<i>Σ</i>	<i>€/tCO<sub>2</sub></i>	9	9	9	9	9
<i>Storage</i>	<i>Capital cost</i>	<i>€/tCO<sub>2y</sub></i>	104	104	104	104	104
	<i>Variable cost</i>	<i>€/tCO<sub>2</sub></i>	37	37	37	37	37
	<i>Σ</i>	<i>€/tCO<sub>2</sub></i>	50	50	50	50	50
<i>Subtotal: CCTS costs</i>			134	134	131	127	124
<i>Total: Returns – Costs</i>		<i>€/tCO<sub>2</sub></i>	102	138	188	219	252

#### 4.4 Regional Scenario: *NorthSea\_40%* Scenario with EOR Option

The *NorthSea\_40%* scenario assumes the same CO<sub>2</sub> price path as the *EU\_40%* scenario (see Table 1). Scenario results show that the use of CCTS is still only economical for the industrial sector, particularly iron and steel making plants. These facilities invest in a CCTS infrastructure from 2015 to 2020 in order to gain profits from additionally recovered oil from CO<sub>2</sub>-EOR from 2025 onward. After the exhaustion of most of the CO<sub>2</sub>-EOR fields in 2030, new storage sites in saline aquifers and depleted hydrocarbon fields closer to the shore are being used (see Figure 7 for the CO<sub>2</sub> flows in 2050). In this

<sup>10</sup> A conversion rate of 0.33 tCO<sub>2</sub>/bbl (Mendelevitch, 2014) and 1.25\$/€ is being used. Additional capture costs for a coal-fired power plant equipped with post-combustion capture are calculated including a 5% discount rate and 30 years of operating life. The transport costs are estimated by assuming a 500 km long pipeline, with a lifetime of 30 years and a 5% discount rate. CO<sub>2</sub>-EOR equipment is expected to have a much shorter operating life of 10 years and the same discount rate of 5%.

scenario, a total of 2.5 bn tCO<sub>2</sub> is stored until 2050 with annual storage volumes of around 100 MtCO<sub>2</sub>. The required CO<sub>2</sub> transport network spans approximately 15,000 km. The scenario indicates that the CO<sub>2</sub>-EOR technology could lead to additional early economic incentives for the construction of a CCTS infrastructure. Existing infrastructure can be used after the exploitation of the CO<sub>2</sub>-EOR potential in the North Sea as soon as the CO<sub>2</sub> price is high enough. In case of the CO<sub>2</sub> price path remaining around 50 €/tCO<sub>2</sub> like in the *EU\_40%* scenario, it is, however, still only economical for several industrial facilities such as steel or cement. The investment costs sum up to 50 €bn with additional variable costs of 150 €bn until 2050. Revenue from selling additionally recovered crude oil sums up to 300 €bn. Thus, even if investments in CCTS infrastructure are more than recovered, CO<sub>2</sub> price signals far beyond 50 €/tCO<sub>2</sub> are needed to establish long-term use of CCTS.

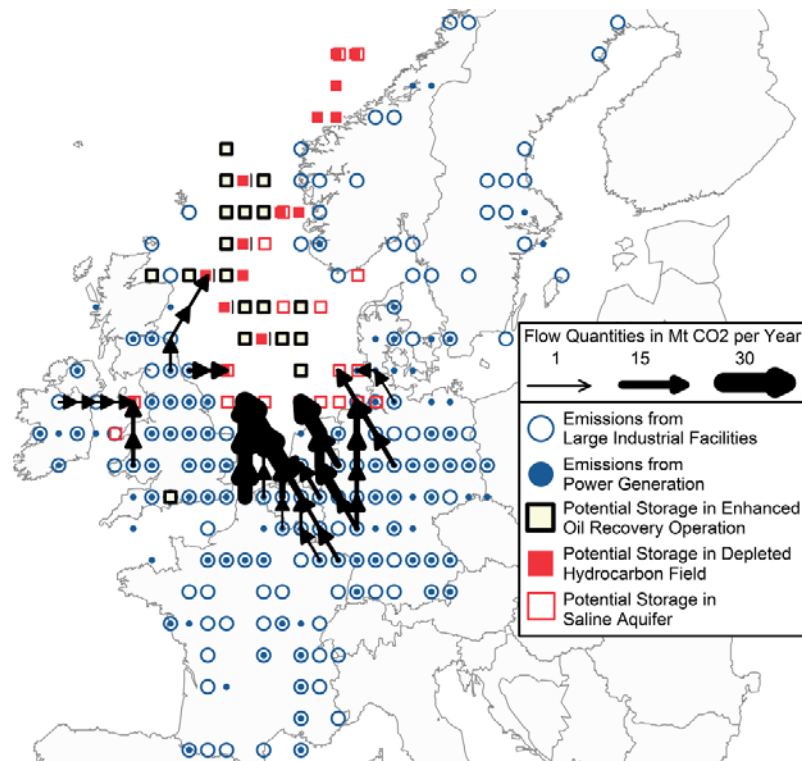


Figure 6: CO<sub>2</sub> flows in the *NorthSea\_40%* scenario in 2050 after EOR-fields are exploited.

#### 4.5 Regional Scenario: NorthSea\_80% Scenario with EOR Option

The *NorthSea\_80%* scenario assumes the same CO<sub>2</sub> price path as in the *EU\_80%* scenario (see Table 1). Until 2035 – the point when the CO<sub>2</sub>-EOR operation stops due to depletion – results of the *NorthSea\_80%* scenario are very similar to those of the respective *NorthSea\_40%* scenario. From 2020 onwards an average of 100 MtCO<sub>2</sub> is transported each year from steel and cement facilities into CO<sub>2</sub>-EOR operations in the North Sea (see Figure 8). Once CO<sub>2</sub>-EOR resources are depleted, further CO<sub>2</sub> capture activity is solely incentivized by the CO<sub>2</sub> certificate price, which has to cover at least the variable costs but also potential new investment costs. New storage in non-CO<sub>2</sub>-EOR locations is being developed close to the shore and close to already existing transport routes. From 2035 onwards, with prices exceeding 75 €/tCO<sub>2</sub>, additional more distant industrial facilities start running their capturing units. Similar to the results from the respective *EU\_80%* scenario without the CO<sub>2</sub>-EOR option, power plants only start capturing their CO<sub>2</sub> from 2040 onward. The network required to accomplish the CO<sub>2</sub> transport spans 27,000 km connecting the sources to the North Sea storage sites (see Figure 9). The investment costs sum up to 190 €bn and there are an additional 540 €bn variable costs over the whole time period until 2050 (see Figure 10). Revenues from selling additionally recovered crude oil sum up to 300 €bn, similar to the results in the *NorthSea\_40%* scenario. However, in contrast to the *NorthSea\_40%* scenario, in this scenario the high CO<sub>2</sub> price creates also enough incentive to pursue CCTS even after the depletion of CO<sub>2</sub>-EOR resources and eventual leads to a full deployment of the technology in the modeled sectors.

Note that the total amount of CO<sub>2</sub> captured is lower than in the *EU\_80%* scenarios without the CO<sub>2</sub>-EOR option because this analysis is concentrating on the riparian countries of the North Sea only. However, like in the *EU\_80%* scenario, all examined industrial facilities and power plants start using the CCTS technology at some point; with the industry still holding the higher share of total stored emissions over time.

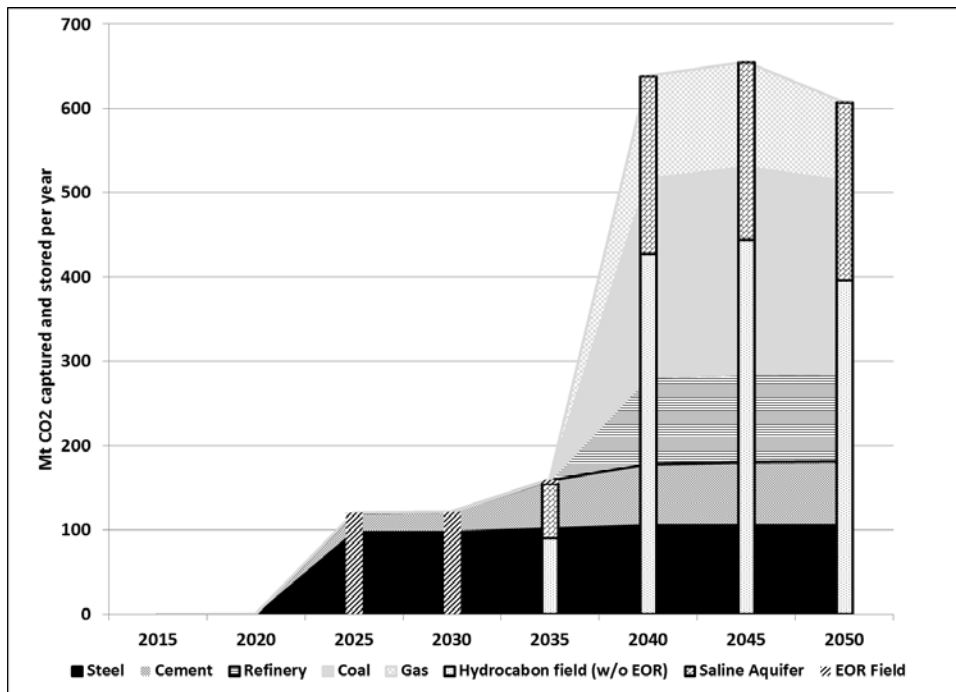


Figure 7: Captured CO<sub>2</sub> emissions by sector and storage type over time in the *NorthSea\_80%* scenario.

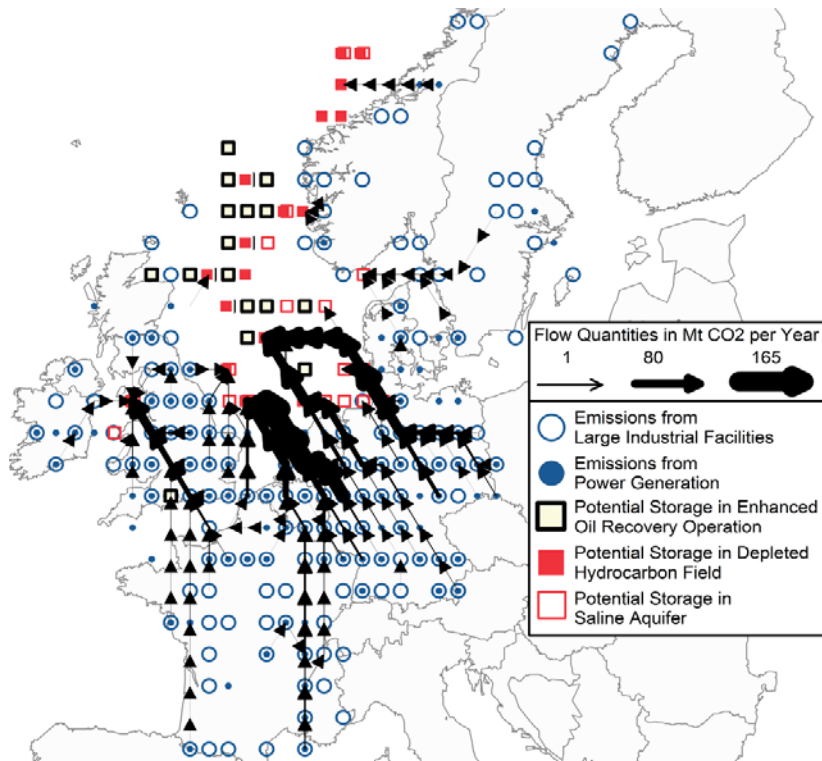


Figure 8: CO<sub>2</sub> flows in the *NorthSea\_80%* scenario in the year 2050 after CO<sub>2</sub>-EOR fields are exploited.

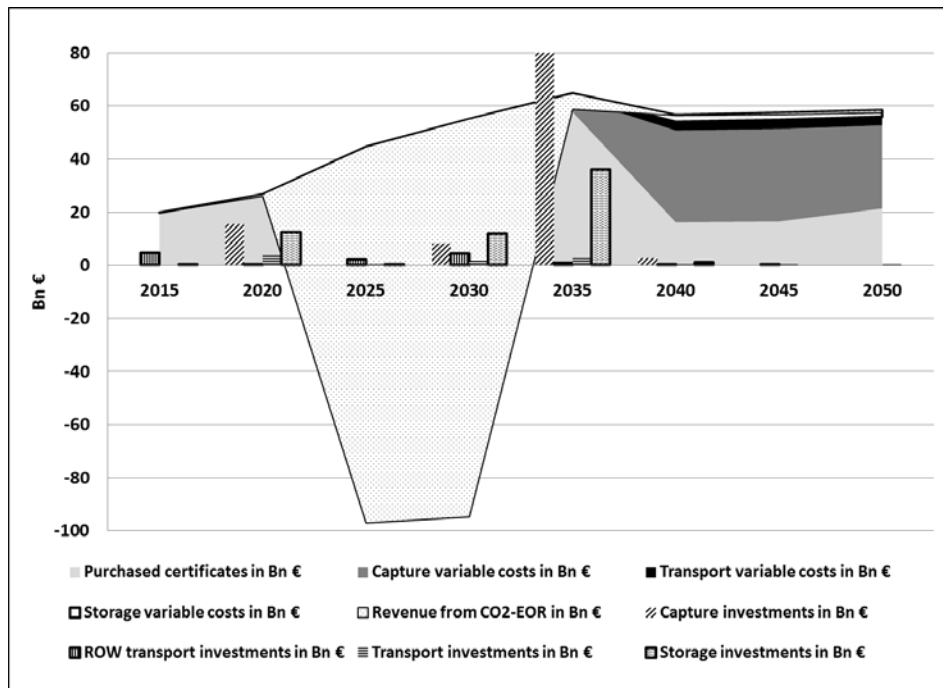


Figure 9: Cost distribution over the whole timespan in the *NorthSea\_80%* scenario in Bn €.

#### 4.6 Regional Scenario: *DNNU\_80%* Scenario Focusing on CO<sub>2</sub>-EOR in DK, NL, NO and UK

Against the background of negative public opinion towards CCTS and lack of industry and policy commitment in Germany, but also in France, Belgium and Sweden, we examine an additional scenario where only Denmark, the Netherlands, Norway and the UK have the possibility to use the CCTS technology. By contrast to the other European countries, these four have a higher potential to use the captured CO<sub>2</sub> to generate additional revenue in the domestic oil industry, or at least still back the application of CCTS in the industry sector (like in the Netherlands). Moreover, UK and Norway are still the only two signatories to the amended London Protocol to allow transnational CO<sub>2</sub> transport for offshore storage (GCCSI, 2014), and these four are among the most advanced countries to be ready for large-scale CO<sub>2</sub> storage operation (GCCSI, 2015). Our goal is to compare these results to the results of the other scenarios and to examine to which extent CCTS deployment is reduced due to a lack of economies of scale.



Similar to the previous scenarios, the use of CCTS is mainly economical for the industrial sector, particularly iron and steel making plants. In the *DNNU\_80%* scenario facilities invest in a CCTS infrastructure from 2015 to 2020 in order to gain profits from additionally recovered oil from CO<sub>2</sub>-EOR from 2025 onward. Around 100 MtCO<sub>2</sub> is stored annually until the full exhaustion of the CO<sub>2</sub>-EOR resources, 10 to 15 years after the beginning of the operation. From 2035 onwards, additional storage sites in saline aquifers and depleted hydrocarbon fields closer to the shore are used by industrial facilities already equipped with CO<sub>2</sub> capture. With CO<sub>2</sub> prices exceeding 75 €/tCO<sub>2</sub> in the *DNNU\_80%* scenario, additional, more distant industrial facilities start investing in capture units. Power plants only start using the CCTS chain from 2040 onwards, similar to the outcome of previous scenarios without the CO<sub>2</sub>-EOR option.

For the period of the CO<sub>2</sub>-EOR boom (2025-2040), the results of the *DNNU\_80%* scenario on length of the pipeline network are similar to those of the *NorthSea* scenarios. While distances to deliver CO<sub>2</sub> up to the shore are shorter on average, CO<sub>2</sub> from the UK takes especially long routes offshore to arrive at a CO<sub>2</sub> storage site with CO<sub>2</sub>-EOR option (see Figure 11). The overall installed pipeline network in 2030 covers over 11,000 km (10,200 in the *NorthSea* scenarios) Similarly, the values for average investment in CO<sub>2</sub> transport and CO<sub>2</sub> storage per MtCO<sub>2</sub> per year during the initial phase in 2025 do not change for the *DNNU* scenario (cf. Table 7)<sup>11</sup>. Due to a similar deployment of the technology no economies-of-scale effect between the *NorthSea\_80%* scenario in 4.5 and the *DNNU\_80%* scenario can be observed during this period. However, the *DNNU\_80%* scenario exhibits a shift in CO<sub>2</sub>-EOR utilization. We find that UK CO<sub>2</sub>-EOR storage potential used by France and Belgium in the other scenarios is now intensively used to store domestic CO<sub>2</sub> from UK (increase of 46 MtCO<sub>2</sub> per year for the period from 2025 to 2040 in the UK). The same effect but to a smaller extent (9 MtCO<sub>2</sub> per year) can be observed with Norway. Danish oilfields that stored CO<sub>2</sub> from Germany in the other scenarios, now increasingly receive CO<sub>2</sub> from the Netherlands (increase of 27 MtCO<sub>2</sub> captured per year in the Netherlands in the period from 2025 to 2040). At the same time, capture activity in Denmark does not

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<sup>11</sup> To assess economies of scale for the CO<sub>2</sub>-EOR boom period one has to compare 2025 values from Table 7. Values for 2030 also include investments for non-CO<sub>2</sub>-EOR induced CO<sub>2</sub> transport and storage, as investments the model features a 5 year construction period before infrastructure can be used.

change significantly. After the CO<sub>2</sub>-EOR boom, the storage volumes for the four countries do not differ between the different scenarios. A clear economies-of-scale effect can be observed for the post-CO<sub>2</sub>-EOR period. In 2040 average investment costs in both CO<sub>2</sub> transport and storage infrastructure are therefore much higher for the *DNNU* scenario compared to the *NorthSea* scenarios (by 30% and more, cf. Table 7) . The constructed transport network is much smaller than in the *NorthSea\_80%* scenario (13,600 km compared to 26,800 km) which is due to a smaller observed area and the lack of economies of scale. The Table 8 summarizes the key results of the *NorthSea* and *DNNU* scenarios. Due to their regional focus, volumes of CO<sub>2</sub> stored and required transportation distances in these scenarios are likely to be shorter than in the European-wide scenarios of section 2.3.

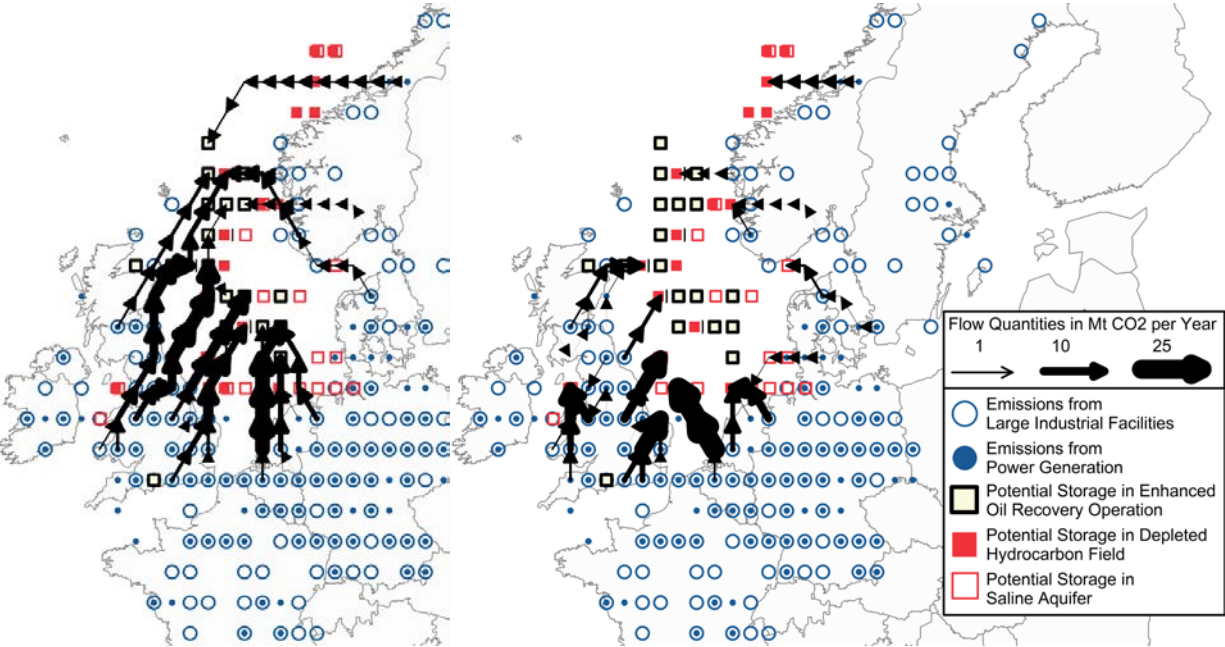


Figure 10: CO<sub>2</sub> flows in the *DNNU\_80%* scenario in 2025 using the EOR-option (left) and in 2050 after EOR-fields are exploited (right).

Table 7: Average investment in CO<sub>2</sub> transport and CO<sub>2</sub> storage per MtCO<sub>2</sub> per year, comparing the *NorthSea\_80%* and *DNNU\_80%* scenarios.

	Coverage	2025	2030	2035	2040
Avg. Invest. in CO <sub>2</sub> Transport per MtCO <sub>2</sub> per year	All North Sea Region	0.07	0.09	0.11	0.03
	DK, NL NO, UK	0.07	0.07	0.09	0.07

Avg. Invest. in CO <sub>2</sub> Storage per MtCO <sub>2</sub> per year	All North Sea Region DK, NL NO, UK	0.10	0.11	0.16	0.10
		0.10	0.10	0.16	0.15

Table 8: Summary of regional results.

Scenario	Pipeline Network [th. km]		Stored Emiss. until [GtCO <sub>2</sub> ]		Origin. from industry [%]	Storage left in 2050 [GtCO <sub>2</sub> ]	CCTS invest. costs [€bn]	CCTS var. costs [€bn]
	2030	2050	2030	2050				
	NorthSea_40%	14.2	15.4	0.6	2.5	100	40.0	47.2
NorthSea_80%	10.2	26.8	0.6	8.5	54	34.6	191.9	539.3
DNNU_80%	11.0	13.6	0.6	3.1	57	36.4	61.7	232.4

## 5 CONCLUSION

In this paper we present scenario analysis and interpretation on the potential role of CCTS to support the EU energy system transition to meet emissions reductions goals that are consistent with an international goal of staying below 2°C of global warming. The assumptions of the moderate scenarios include a CO<sub>2</sub> price of 50 €/tCO<sub>2</sub> in 2050 which triggers hardly any CCTS development in Europe. More stringent climate scenarios aim at an 80% GHG reduction until 2050. The resulting CO<sub>2</sub> price of 270 €/tCO<sub>2</sub> in 2050 pushes all EU-ETS industry and energy sectors to use CCTS at some point. It is, however, the iron and steel sector which starts with the deployment as soon as the CO<sub>2</sub> certificate price rises above 50 €/tCO<sub>2</sub> in 2030. The cement sector follows some years later at a threshold of around 75 €/tCO<sub>2</sub>. It is only with CO<sub>2</sub> certificate prices exceeding 100 €/tCO<sub>2</sub> that CCTS becomes lucrative for the electricity sector. Sensitivity analysis shows that the future development of a CCTS infrastructure is more sensitive to its variable than its investment costs. The use of onshore storage sites is unlikely in Europe due to high public resistance, increasing the transport distances. The resulting CO<sub>2</sub> transport network required to connect emission sources and storage sites across Europe would comprise of up to 45,000 km of pipeline and store up to 1,000 MtCO<sub>2</sub> per year.

Additional revenues from applying CO<sub>2</sub> enhanced oil recovery (CO<sub>2</sub>-EOR) in the North Sea lead to an earlier adoption of CCTS starting in 2025 independent from the CO<sub>2</sub> certificate price. The lifespan of most of the CO<sub>2</sub>-EOR operations is expected to be around ten years. It is followed by conventional CO<sub>2</sub>-

storage in nearby depleted hydrocarbon fields and saline aquifers if the CO<sub>2</sub> certificate price exceeds the sector-specific thresholds to cover variable costs of carbon capture. Generally, the use of CO<sub>2</sub> for EOR projects is criticized by environmental organizations as the overall CO<sub>2</sub> mitigation effect is negative if considering the CO<sub>2</sub> content of the additional extracted oil.

Taking into account the realities that confront CCTS in the EU, political and public opposition has left only a handful of countries that still consider building CCTS in the medium term. A 20% CCTS penetration rate in the European power sector as calculated in the *DNNU\_80%* scenario in 2050 thus seems more realistic. Concentrating on Denmark, the Netherlands, Norway and the UK, this scenario shows an increased utilization of CCTS-EOR especially in the UK and the Netherlands. However, a lack of economies of scale leads to increasing average costs in both CO<sub>2</sub> transport and storage infrastructure, once the EOR-fields have been exploited.

A critical point of our analysis is that the employed model (CCTS-Mod) is purely cost-driven and does not include any specific bound on the CCTS penetration. The model assumes a cost-minimizing player with perfect foresight and therefore tends to overestimate the potential for CCTS. Additional legal and environmental issues with respect to transboundary CO<sub>2</sub> transport as well as CO<sub>2</sub> storage and liability issues are not included in the model. Real costs are expected to be higher and come with a lower deployment of CCTS in the future. Considering the large number of different players and technologies, the insecurities regarding CO<sub>2</sub> prices, learning rates, legal issues, public resistance and further policy measures strongly questions the fact whether CCTS may be able to fulfill its role as a bridging technology for the decarbonization of Europe.

The driver behind all global CCTS projects that will become operational in the near future or have started operation recently (e.g. Boundary Dam, Canada) is CO<sub>2</sub>-EOR. The underlying regulatory frameworks and support schemes can primarily be regarded as a cross-subsidization of the petroleum industry, while progressing the CCTS technology is of secondary interest. This is underpinned by observations in the Gulf States, USA and Canada, where the legislative framework on CO<sub>2</sub>-EOR with CO<sub>2</sub> recycling is established, while the framework for long-term storage (which would be the primary goal of CCTS) is underdeveloped. The same is true for Europe, where the emergence of a regionally focused

network around the North Sea, including only some riparian countries using offshore CO<sub>2</sub> storage with CO<sub>2</sub>-EOR, is the most likely option. The mirage of a Pan-European network for CCTS in the EU-ETS industry and energy sectors, like envisioned in some long-term scenario projections, seems out of reach at present due to a combination of a lack of financial incentives as well as too little political and public support for CCTS as a mitigation technology. Further research, however, is needed to evaluate the effects of the newest European reforms (e.g. the reform of the EU Emissions Trading System ETS) as well as national regulations (e.g. emissions performance standards (EPS) and contract for differences (CfD) in the UK) on the development of CCTS.

## **ACKNOWLEDGEMENT**

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