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Carbon Capture, Transport and Storage in Europe

A problematic energy bridge to nowhere?

CEPS Working Document No. 341/November 2010

Johannes Herold, Sophia Rüster

and

Christian von Hirschhausen

Abstract

This paper summarises the findings of work package 5.3 of the SECURE project, with regard to the role of carbon capture, transport and storage (CCTS) for the future European supply security of coal. The real issue in European supply security with respect to coal is the absence of an economically and politically sustainable use of coal for electricity, liquefaction, gasification, etc. Whereas earlier papers delivered for work package 5.3 on the coal sector indicated that there are few risks to the European energy supply of (steam) coal, there is an implicit supply security threat, i.e. that coal will no longer be an essential element of European energy supply because the CCTS rollout will be delayed or not be carried out at all. This thesis is substantiated in this subsequent paper, with more technical details and some case study evidence.

This Working Document is a follow-up to the SECURE project, financed by the European Commission to study the "Security of Energy Considering its Uncertainties, Risks and Economic Implications". The SECURE project was carried out by 15 major European research institutions over three years (2008–10). Johannes Herold, Sophia Rüster and Christian von Hirschhausen led the SECURE project work package on coal (WP 5.3). This paper expands on the policy conclusions of WP 5.3, published as CEPS Policy Brief No. 224 by Hirschhausen et al. (2010); however, this report is not a deliverable of the SECURE project itself, and is solely attributable to the authors.

ISBN 978-92-9079-6138-066-1

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CARBON CAPTURE, TRANSPORT AND STORAGE IN EUROPE

A PROBLEMATIC ENERGY BRIDGE TO NOWHERE?

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JOHANNES HEROLD, SOPHIA RÜSTER AND CHRISTIAN VON HIRSCHHAUSEN*

Introduction

In recent years global coal use has risen at a rate of 4.9% annually despite increased awareness of climate change (WCI, 2010). It is sometimes argued that carbon capture, transport and storage (CCTS) hold the potential to function as an 'energy bridge' between the use of fossil fuels and a future renewable-based, largely carbon-free energy system. Thus, the Intergovernmental Panel on Climate Change (IPCC) (2005) has concluded that CCTS could contribute between 15 and 55% of the cumulative effort to reduce emissions by 2100, which gives it a central role within a portfolio of the low-carbon technologies needed to address climate change. The International Energy Agency (IEA) (2008) has analysed a number of global greenhouse gas (GHG) reduction scenarios and concluded that CCTS is "the most important single new technology for CO_2 savings" in both power generation and industry. According to the IEA's "Technology Roadmap", the next decade is a critical period for CCTS (IEA, 2009). In the IEA's "Blue Map" scenario, total investment in 100 capture plants, a minimum of 10,000 km of pipelines and storage of 1.2 $GtCO_2$ will be required to transform CCTS into a serious abatement technology by 2050.

Yet there is a real danger that the ambitions for CCTS deployment over the next decade will not be met. Our extended CCTS project database shows that the 2020 IEA target will not be reached if we continue at the speed and scale observed during the last decade. The lack of progress arises from the absence of determination by public authorities to overcome the significant obstacles inherent in CCTS coupled with industry hesitation towards embracing a technology that challenges the traditional business model of coal electrification. Moreover, the business model of CCTS plants (base- and mid-load) is incompatible with the dispatch of a largely renewable-based electricity system that values flexibility over baseload.

Ironically, this scenario may give rise to a supply security paradox: whilst sufficient coal is available worldwide and can be supplied to Europe without major danger of disruption, the *use* of this coal for electrification and other purposes may be restricted because the failure of CCTS will be a barrier to the continued traditional use of coal.

This Working Document addresses the prospects of, and the obstacles to a CCTS rollout, as specified in some of the scenarios. Our main hypothesis is that given the substantial technical and institutional uncertainties, the lack of a clear political commitment, and the available alternatives of low-carbon technologies, CCTS is unlikely to play an important role in the future energy mix; it is even less likely to be an 'energy bridge' to a low-carbon energy future.

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* Johannes Herold is Research Associate at TU Berlin, Sophia Rüster is Research Associate at Florence School of Regulation and Christian von Hirschhausen is a Professor at TU Berlin. The authors would like to thank Manfred Hafner for providing project leadership and the framework for the analysis, and Christian Egenhofer and the CEPS team for editorial assistance.

The paper first discusses unresolved issues along the value-added chain, including an assessment of the critical issues in CO_2 separation, transportation and storage. The focus of our analysis is Europe, although we also refer to experiences and ongoing research in the rest of the world, mainly North America (US and Canada) and Australia. We find that the price tag along the chain by far exceeds competitive levels, and that technical and institutional uncertainty further decreases the likelihood of the CCTS option. Section 2 provides an overview of CCTS developments beyond Europe. We contrast the very optimistic IEA (2009) roadmap with the meagre results obtained thus far in pilot projects. This analysis is based on a comprehensive analysis of CCTS projects worldwide, documented in the appendices: amongst the 69 projects announced, only 7 are now operating and – given a size of between 5 and 40 MW – none of them qualifies as a demonstration plant. We also highlight the difference between the situation in Europe and in North America, where a positive value of CCTS in terms of enhanced oil and gas recovery provides a higher financial incentive for CO_2 separation, but work to overcome obstacles to long-term sequestration seems to be making slow progress there as well.

Section 3 summarises the findings of an extensive modelling exercise of the European CCTS infrastructure: we find that CCTS can contribute to the decarbonisation of Europe's energy and industry sectors only under very 'favourable' conditions, such as very high CO_2 prices and optimistic assumptions about CO_2 storage capacities. By contrast, the more likely scenario is a decrease of available storage capacity or a more moderate increase in CO_2 prices; both will significantly reduce the role of CCTS as a CO_2 mitigation technology, especially in the energy sector. Section 4 focuses on the situation in Europe and potential investments to incentivise CCTS at the European level: whereas the main impetus for demonstration has come from the €1 bn earmarked for CCTS in the European Economic Recovery Plan, longer-term support schemes are necessary if any significant impact of the technology is to be expected. Section 5 concludes on a conservative note and provides concrete policy recommendations. The potential contribution of CCTS to a decarbonised Europe should be reconsidered given the new data available on costs, a better understanding of the complexity of the process chain and the reduced storage potential.

1. Unresolved issues along the value-added chain

Carbon capture, transport and storage defines the process by which CO_2 from large point sources such as fossil fuel power plants and industrial sources is captured, compressed, transported and stored underground. CCTS can be seen as an instrument to mitigate the impact of fossil fuel combustion on global warming. The near-term technology options available for CCTS deployment are well known, but only on a smaller or medium scale, on a component level and from non-CCTS applications. The three technologies are pre-combustion capture, the oxy-fuel process and retrofitable post-combustion capture. Still, the scaling of these technologies and their applications to large CO_2 emitters raises new questions that can only be answered in large-scale demonstration projects.

1.1 Upstream: CO_2 capture

For some time, the small-scale capture of CO_2 has been used by the chemical industry and in some parts of the energy sector. Near-term technologies, such as post-combustion and pre-combustion capture and oxy-fuel technology, differ in maturity and time horizons for commercial viability. We focus exclusively on these first-generation capture technologies. All CCTS technologies aim at creating a highly concentrated or pure stream of CO_2 ready for transport to a storage site. Table 1 shows that the choice of the appropriate capture technology is mainly driven by the fuel and the resulting CO_2 concentration in the flue gas.

Table 1. CO_2 concentrations and pressures of different combustion cycles

Flue gas	**CO_2 concentration $\%_{vol}$ (dry)**	**Pressure of gas stream (bar)**
Natural gas-fired boilers	7-10	1
Gas turbines	3-4	1
Oil-fired boilers	11-13	1
Coal-fired boilers	12-14	1
IGCC* after combustion	12-14	1
IGCC synthesis gas after gasification	8-20	20-70
IRCC** synthesis gas after reforming	13-17	20-40

* Integrated gasification combined cycle

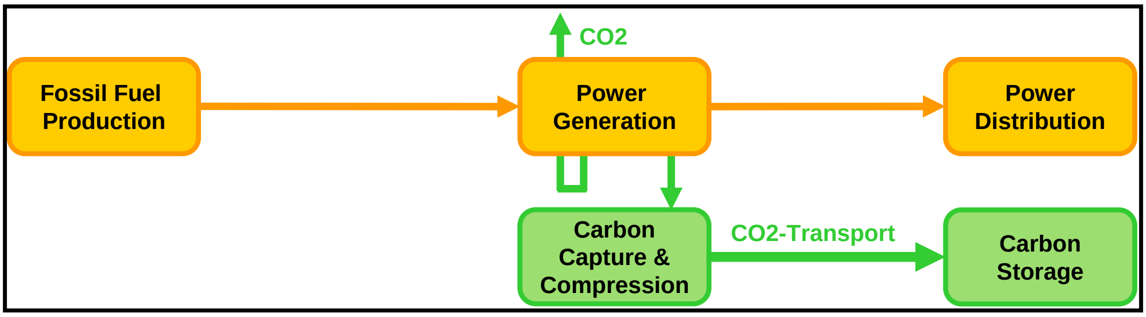
** Integrated reformation combined cycle

Source: Buhre et al. (2005).

1.1.1 Post-combustion capture

Post-combustion capture separates the CO_2 out of the flue gas after combustion (see Figure 1). This process is comparable to flue gas desulphurisation, which has long been mandatory for power plants to filter SO_x emissions. The technology was first applied in the 1980s for the capture of CO_2 from ammonia production plants. The captured CO_2 is used in food production, e.g. to carbonate soft drinks and soda water. Post-combustion chemical absorption technologies represent one of the most commercially available CO_2 capture technologies and the high compatibility with existing power plants (retrofitting) makes this technology the most attractive mid-term option.

Figure 1. Extended value chain including the post-combustion process



Source: Own illustration.

Depending on the carbon content of the fuel and the amount of excess air, the CO_2 reaches concentrations in the flue gas of between 3% for natural gas and up to 15% for pulverised coal (Wuppertal Institute, 2007). The CO_2 concentration determines which post-combustion capture process can be applied. Two procedures are applicable:

1(a). *Chemical absorption* in combination with heat-induced CO_2 recovery is less sensitive to low CO_2 concentration and partial pressure and is applicable to natural gas plants. The CO_2 in the flue gas is chemically bonded by a monoethanolamin (MEA) or ammonia solution. The fundamental reaction for the reversible MEA process is

$$C_2H_4OHNH_2 + H_2O + CO_2 \leftrightarrow C_2H_4OHNH_3^+ + HCO_3^- .$$

In a subsequent step, the MEA solution is heated to 100-120°C in a stripper and releases the CO_2, which is then compressed and transported to a storage site. The regenerated solution is cooled down to 40-60°C and recycled back into the process. Due to the strong bonding between MEA and CO_2 and the resulting high level of energy consumption for releasing CO_2, other solvents like sterically-hindered amines are now under development (IEA, 2004). They require less energy in the form of steam consumption to release the CO_2, i.e. 0.9 MWh_{th}/tCO_2 for a 90% recovery rate (Mimura et al., 2003). One drawback is that the MEA solution is subject to degeneration and must be replaced constantly.

So far the technology has only been used for the treatment of very clean gas mixtures containing no or few impurities such as dust, SO_x and NO_x (Kanniche et al., 2010). Plants are capable of capturing 1,000 to 4,000 tCO_2/d. Coping with the emissions of a 1 GW lignite power plant requires up-scaling to 13 $ktCO_2$/d (Vallentin, 2007).

1(b). *The chilled ammonia process* uses ammonia instead of MEA. The process is carried out at temperatures of between 0 and 10°C and requires cooling the flue gas. The advantage of the process is the reduced energy demand, less than 0.55 MWh/tCO_2, for the desorber (Dardea et al., 2009). Compared with MEA, the solvent does not degrade and has a high CO_2 capacity.[1]

2. *Physical absorption* in a pressure swing absorption–desorption system (Benfield process) is an alternative to highly corrosive MEA. However, it requires higher pressure (15 bar) and concentrations of CO_2 in the flue gas (>10%). Calculations by Kothandaraman et al. (2009) show that for a CO_2 content of 12% in the flue gas, the minimum reboiler load without energy recuperation is 0.88 MWh/tCO_2. Given the high pressure requirements and impurities in the flue gas this process is mainly applicable to integrated gasification combined cycle (IGCC) and integrated reformation combined cycle (IRCC) plants. In comparison the MEA process requires additional energy of at least 1.17 MWh/tCO_2 for the reboiler, which, when including compression, corresponds to a 25% loss in thermal efficiency for a coal plant.

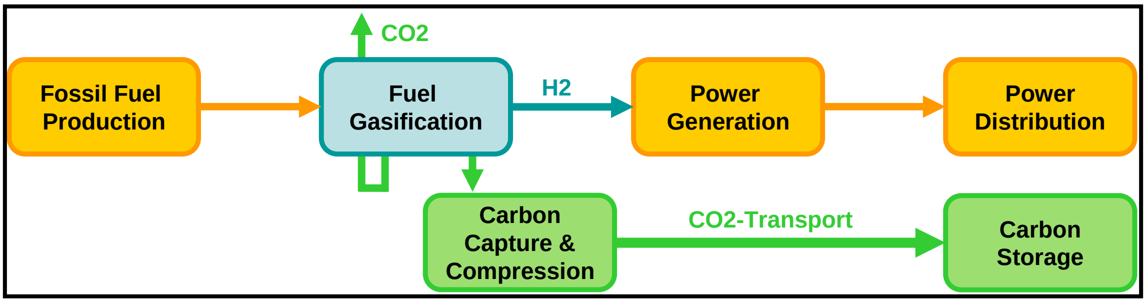
In summary, the obstacles to widespread adoption of post-combustion carbon capture are impurities in the flue gas, the handling of large volumes of gases, the handling of toxic chemicals, the high degree of efficiency losses of the power plant and the reduced ability to follow load changes.

1.1.2 Pre-combustion capture

Pre-combustion capture refers to the treatment of CO_2 and H_2 after the gasification process of coal, biomass or the steam reformation of natural gas (see Figure 2). CO_2 and H_2 can be separated by physical absorption, as the mixture of gases is under pressure and contains a high concentration of CO_2 (Table 1).

[1] A pilot plant that uses chilled ammonia to capture CO_2 has been built by Alstom, the Electric Power Research Institute and American Electric Power in Oklahoma to test the process (which was granted a patent in 2006) and to demonstrate low-ammonia emissions.

Figure 2. Extended value chain including the pre-combustion process



Source: Own illustration.

Decoupling the carbon separation from the electricity production offers some advantages. Plants can react to load changes more easily; the gasification process is best carried out in a continuous process, but a gas turbine in combination with hydrogen storage offers flexible utilisation of the power plant; and the hydrogen can be used in other applications, such as in chemical industries or to power electric vehicles.

The gasification process can be undertaken with ambient air or with pure oxygen. The latter process increases the efficiency of the gasification and separation process. Yet the separation of oxygen from nitrogen (as undertaken in the oxy-fuel process) requires investment in an air separation unit, which increases auxiliary power. The fundamental reactions are presented below.

First, the fuel reacts with oxygen to formulate CO and H_2:

$$C_nH_m + \frac{n}{2}O_2 \rightarrow \frac{m}{2}H_2 + nCO + Q \text{ and}$$

$$C_nH_m + nH_2O \rightarrow \frac{n+m}{2}H_2 + nCO - Q \,.$$

Second, the CO reacts with water to formulate CO_2 and H_2:

$$CO + H_2O \rightarrow H_2 + CO_2 \,.$$

The synthesis gas (syngas) contains 35-40%$_{vol}$ CO_2 (and more if pure oxygen is used instead of air) and the hydrogen and carbon dioxide are physically separated through pressure swing absorption (CAN Europe, 2003). The process can be based on methanol or dimethylether (Selexol process) as well as on the active amine-based chemical solvent (MDEA). The process is less expensive in terms of investment and efficiency losses.

The hydrogen fires a gas turbine and a subsequent steam turbine or can be used to power electric vehicles. The resulting emission in both applications is a relatively pure stream of water vapour. Modern gas turbines, however, accept hydrogen concentrations of only up to 60% in order to limit the flame temperature. Further research is needed to develop turbines that accept higher concentrations or pure hydrogen to increase IGCC efficiency.

Rezvani et al. (2009) estimate investment costs of between €1,602 and €1,909/kW for a 450 MW$_{el}$ IGCC plant including CO_2 capture and compression depending on the specific technologies. The energy penalty, according to Kanniche et al. (2010), is around 22 points, dropping from 43% to 33.5%.

Pre-combustion capture is not applicable to existing power plants other than IGCC and IRCC. Because of the limited number of such plants operating, the coal-based IGCC technology itself is still in the demonstration phase and pre-combustion capture is most likely a limited option for industrial applications. Proven refinery-based plants are not based on coal due to the increasing process complexity, nor do they use the hydrogen for power generation.

In the US, four IGCC plants, ranging from 107 to 580 MW_{el}, have been constructed with financial support from the US Department of Energy (DOE). Other plants operate in Italy, Spain, Japan and the Netherlands (Table 2).

Table 2. IGCC utilities operating in selected countries

Project name	**Country**	**Start-up**	**Size (MWe)**	**Fuel**
Kentucky Pioneer Energy	US	12/1994	580	High-sulphur bituminous coal and refuse-derived fuel
Tampa Electric Company	US	11/1991	250	Coal
Pinon Pine IGCC Project	US	08/1992	107	Low-sulphur Western coal
Wabash River Coal Gasification Repowering Project	US	07/1992	260	High-sulphur bituminous coal
ISAB Energy IGCC	Italy (Sicily)	1999	512	Asphalt
Elcogas IGCC Power Plant	Spain	1998	335	High ash local coal and petcoke
Nippon Oil Corporation Refinery	Japan	2003	342	Asphalt residue
Willem Alexander plant	Nether-lands	1993	253	Coal and biomass co-firing
Sarlux plant	Italy	2000	548	Heavy hydrocarbons (TAR)

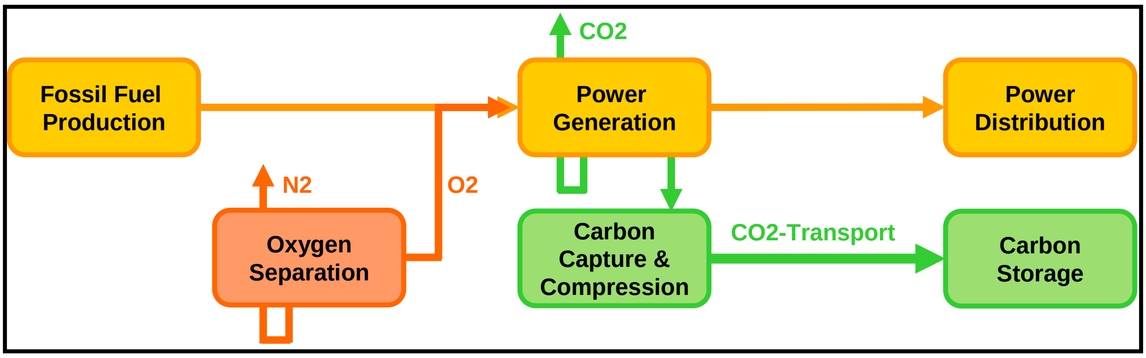
Source: Own compilation from publicly available data.

The chief barrier to deployment of IGCC technology is the high investment cost, i.e. between US$1.2 and 1.6m per MW capacity excluding CO_2 capture and compression (US EIA, 2009). Yet even these cost estimations have proven unrealistic, since many IGCC coal projects have higher expenditures. An example is the US$2.156 bn Mesaba Project (531 MW) (US DOE, 2010). For CO_2 to be captured, an additional US$1 bn would be needed for compression, transport and storage infrastructure. The numbers are in line with Tzimas (2009), who also finds higher investment costs for the first CCTS demonstration projects (as later shown in Table 3).

1.1.3 Oxy-fuel technology

Another strategy to capture CO_2 is the combustion of fossil fuels in a pure oxygen and carbon dioxide atmosphere instead of ambient air (see Figure 3). CO_2 from conventional combustion processes is present as a dilute gas in the flue gas, resulting in costly capture using, for instance, amine absorption. Shifting the CO_2 separation from the flue gas to the intake air results in a highly concentrated stream of CO_2 (up to 80%) after combustion. The remaining gas contains primarily H_2O. Part of the flue gas is recycled into the flame chamber in order to control the flame temperature at the level of a conventional power plant.[2] The water vapour is condensed and the CO_2 stream compressed and transported to the storage site. The main cost driver of the process is the energy-intensive separation of oxygen, which alone can consume up to 15% of the plant's electricity production (Vallentin, 2007; Herzog and Golomb, 2004).

Figure 3. Extended value chain including the oxy-fuel process



Source: Own illustration.

The first attempts to develop and apply the technology were carried out in the 1980s, motivated by the oil industry. The combustion of fuel in a pure oxygen atmosphere has also been undertaken by the glass and steel industry to exploit the higher flame temperatures.

Whilst oxy-fuel combustion technology can be implemented as a retrofit technology for pulverised fuel boilers, it will impact on combustion performance and heat transfer patterns. Other issues to be solved are combustion in a pure O_2/CO_2 atmosphere (for older power plants the leak air reaches levels of 10% and for new plants it is still up to 3%), and the presence of incondensable gases (oxygen, nitrogen and argon) in the CO_2 flow transported in the supercritical state, which can cause vibrations and shock loads in the pipeline as well as mechanical damage (Kanninche et al., 2010).

In summary, the obstacles to widespread adoption of oxy-fuel technology are reduced efficiency (which may further decrease if additional SO_x removal is required), the absence of large-scale technology demonstration, and the higher temperatures of the flue gas not allowing for the electric removal of ash, but instead requiring costly ceramic filters.

1.1.4 Economics of CO_2 capture are highly uncertain

1.1.4.1 Estimates of investment costs

Owing to the energy penalty and the higher capital expenditures of CCTS plants, the costs of electricity production will increase. The true costs of CO_2 abatement by means of CCTS remain unknown in the absence of up-scaled demonstration plants; likewise the expected benefits for electricity producers are unclear given the uncertainty over future carbon prices. Recent estimations (e.g. Tzimas, 2009) calculate higher costs than even a couple of years ago (e.g. Wuppertal Institute, 2007). This is a well-known phenomenon observed for a larger number of innovative energy technologies. A study by Rubin et al. (2006) states that the costs for flue gas desulphurisation or NO_x removal increased because of new standards and changes in the technology. What are most needed are mid- and large-scale demonstration projects to validate

[2] The flame temperature of pulverised coal in pure oxygen is > 1,400°C.

the technology and to show the means to develop the technology further. Table 3 presents recent cost estimations for CCTS demonstration projects.

Table 3. Investment costs of different systems with and without CO_2 capture

Technology	Investment costs, demonstration project in €08/kW	Efficiency (%)
IGCC with carbon capture	2,700	35
Pulverised coal (PC)	1,478	46
PC with carbon capture	2,500	35
Oxy-fuel	2,900	35
NGCC with carbon capture	1,300	46

Source: Tzimas (2009).

CCTS decreases plant efficiency and the greater fuel consumption causes additional emissions. These factors must also be considered to properly compare CCTS with other abatement strategies. Equation (1) shows the relationship between abatement and capture costs following IEA (2006b):

$$C_{aba} = C_{cap} * \frac{CE}{[eff_{new} / eff_{old} - (1\text{-}CE)]} \quad (1)$$

with the parameters defined in Box 1.

Box 1. Parameters in Equation (1)

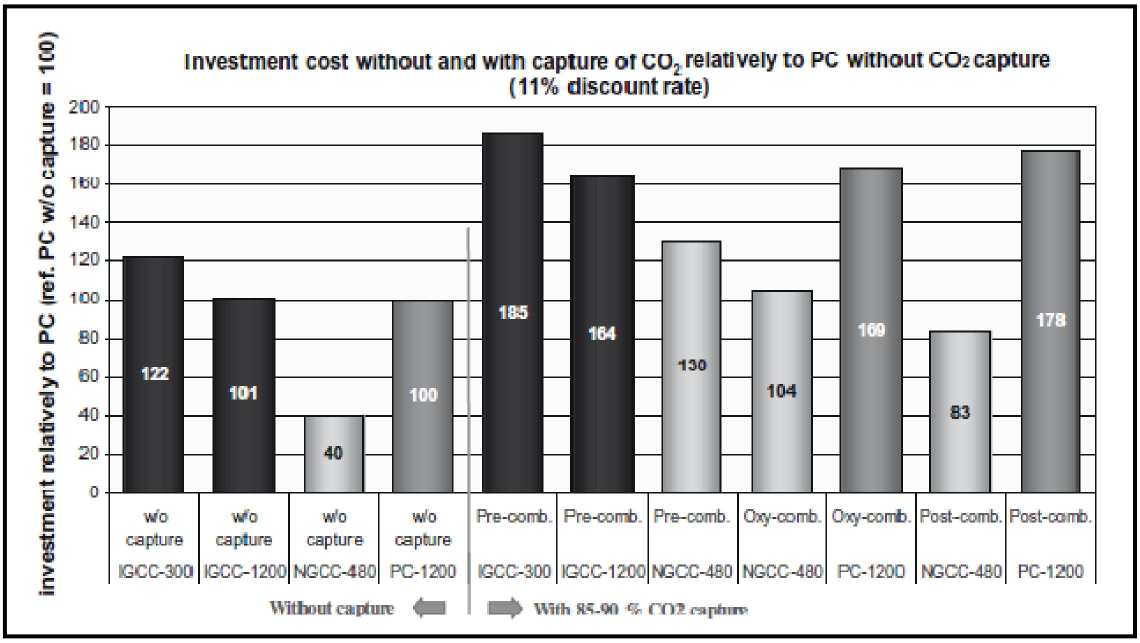
C_{aba}	Abatement costs
C_{cap}	Capture costs
CE	Fraction of carbon captured
eff_{new}	Thermal efficiency of the CCTS plant
eff_{old}	Thermal efficiency of the standard plant

The multiplier for abatement cost c_{aba} relative to capture cost c_{cap} is lower for high-efficiency plants. According to the RECCS study (Wuppertal Institute, 2007), the efficiency losses for an IGCC plant with capture are estimated to be in the 8% range in 2020 (50% efficiency without CCTS). Based on capture costs of €40/tCO_2, the real abatement costs resulting from the higher fuel consumption are

$$\begin{aligned} C_{aba} &= 40€ / tCO_2 * \frac{0.85}{[0.42 / 0.50 - (1 - 0.85)]} = 40€ / tCO_2 * 1.23 \\ &= 49.2\,€ / tCO_2 \end{aligned} \quad (2)$$

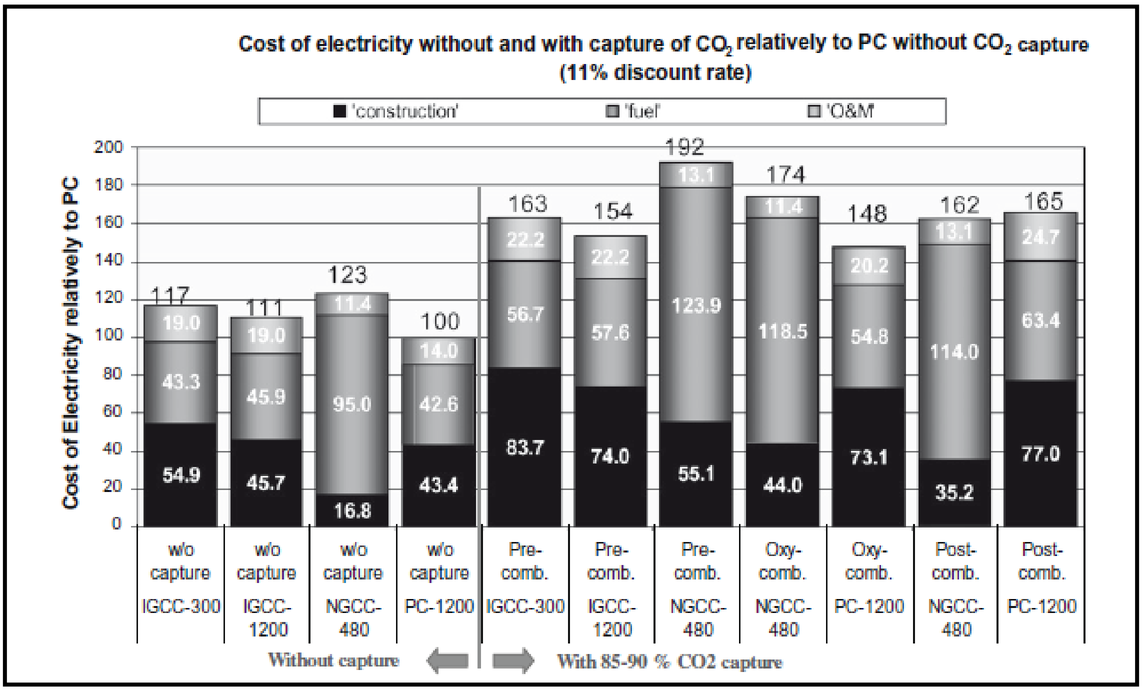
Figure 4 shows the estimated mark-up in investment costs for commercially available CCTS technologies compared with a standard pulverised coal plant and the resulting mark-up in electricity production costs is shown in Figure 5.

Figure 4. Investment costs of different systems with and without CO_2 capture



Source: Kanniche et al. (2010).

Figure 5. Production costs (construction, fuel, operation and maintenance) of the different systems with and without CO_2 capture



Source: Kanniche et al. (2010).

Table A1.1 and Table A1.2 in Appendix 1 summarise the cost estimations for standard and CCTS plants for the year 2020.

CCTS components are expected to benefit from learning effects when market diffusion begins. Efficiency and capture rates will further improve whilst capital costs will decline. Consequently, lower costs compared with CCTS plants built after the research and demonstration phase are expected for those realised in 2020 and later periods. Rubin et al. (2004) estimate the learning rate for CO_2 scrubbers as 11-13% if the installed capacity doubles.

Table A1.3 in Appendix 1 compares the resulting cost estimates for developed CCTS plants in 2020 and further matured plants in 2040. The resulting average CO_2 abatement costs including transportation and storage are estimated to decline within the next decades, but rise again if low-cost storage capacity reaches an eventual end (Table 4).

Table 4. Estimations of future CO_2 abatement costs by means of CCTS

		Time of operation			
		2020	**2030**	**2040**	**2050**
PC	€$_{2000}$/tCO_2	42.6	41.2	39.6	40.1
IGCC	€$_{2000}$/tCO_2	42.6	37.4	36.8	37.3
NGCC	€$_{2000}$/tCO_2	61.0	54.9	48.9	51

Source: Wuppertal Institute (2007).

Cement manufacturing, ammonia production, iron and other metal smelters, industrial boilers, refineries and natural gas wells can be considered as well. These facilities produce CO_2 in lower quantities (<200 MtCO_2/yr in total) but qualify for CCTS (IEA, 2004) because of the higher concentrations of CO_2 in the flue gas, which allow for cheaper capture (see Table 5). Deployment in such industries will foster experience with the CCTS process chain at a lower cost.

Table 5. Typical costs of CO_2 capture for industrial plants

Facility	**€/tCO_2**	**Facility**	**€/tCO_2**
Cement plants	28	Refineries	29-42
Iron and steel plants	29	Hydrogen (pure CO_2)	3
Ammonia plants (pure CO_2)	3	Petrochemical plants	32-36

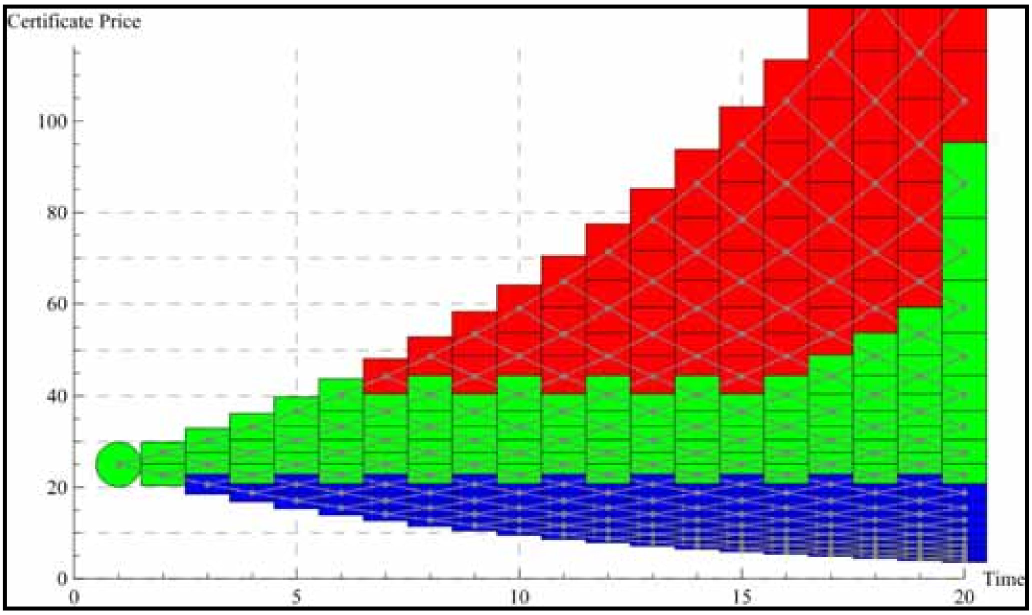
Source: Ecofys (2004).

The extensive database available in work package 5.3.5 of the SECURE project (Herold and Hirschhausen, 2010) shows that amongst the 69 CO_2 capture projects worldwide, only 7 are operating and these are only on a pilot scale. Large-scale demonstration projects like SuperGen in the US and the tender in the UK are presently on hold. Nor is it certain whether the European Recovery Programme could jumpstart the development of its six large-scale capture projects. It is also possible that CCTS technology might never become available; hence we argue that the real cost of CCTS is the drastic increase in the cost of climate mitigation. The IEA Blue Map (IEA, 2009) estimates that attempting to stabilise emissions without CCTS will be 71% more expensive – the equivalent of US$1.28 trillion annually in 2050 (see also Edenhofer et al., 2009).

1.1.4.2 Investment under CO_2 price and technological uncertainty

Geske and Herold (2010) conduct a dynamic stochastic investment analysis of CCTS retrofitting in an environment of CO_2 price and technology uncertainty. It includes the option to invest in, use or shut the CCTS unit. The results show that the main determinate for the application of CCTS is the certificate price. Assuming a thermal efficiency of 33% and a capture rate of 80%, turning off the capture unit is economical when prices drop below €20/tCO_2 (see the lower area in Figure 6; the middle area indicates usage and the upper area indicates a profitable investment opportunity). However, realised technology learning can result in an earlier application of the technology by electricity producers and also act as insurance against the low carbon prices that inhibit profitable CCTS operation.

Figure 6. Investment and management decisions for a post-combustion capture unit



Source: Geske and Herold (2010).

An important finding is the predicted initial investment delay owing to the possibility of benefitting from valuable information about future development. In other words, the chance of an advanced technology becoming available in the future, for instance through publicly funded demonstration projects, is an incentive for investors to postpone application of the CCTS technology.

The authors conclude that all new-build coal power plants must be 'capture ready', because this will ensure technology compatibility and CCTS retrofits at least cost. This goal requires long-term reliable and stable carbon prices high enough to encourage investment in CCTS. Unfortunately, today's somewhat arbitrary carbon caps and the resulting price volatility significantly hamper investment. Given the long capital turnover and life cycle of such investments, plant owners want certainty that their investments will pay off. The authors express criticism about the exclusive attention given by most of the literature on learning effects to the decrease in capital costs. Their analysis indicates that the influence of efficiency improvements in thermal plants plays an important role too, and they suggest more emphasis on CCTS technology learning in the future.

1.2 Midstream: CO_2 transport via pipelines

CO_2 can be transported via a network of pipelines similar to natural gas or crude oil and by truck, train and ship. Transport in a solid state (dry ice) is not an option despite its low transport volume. The amount of energy required to cool the CO_2 (375 kWh/tCO_2) is four times higher than for liquid transport (96 kWh/tCO_2) (Wuppertal Institute, 2007). For the purpose of this paper, we consider on-road or rail transport only as options in the up-scaling phase of CCTS with the pipeline network still under construction.

Pipeline transportation is commonly viewed as the only economical solution onshore for carrying the quantities emitted by large-scale sources.[3] Transportation faces no significant technological barriers and is usually in a liquid or supercritical state to avoid two-phase flow regimes. Transport costs are mainly determined by the high upfront costs for building the network. At year-end 2009, more than 5,000 km of CO_2 pipelines were operating worldwide, transporting 50 Mt/yr (Wuppertal Institute, 2007).

Dry (moisture-free) CO_2 does not react to the carbon-manganese steel customarily used for pipe, even if the CO_2 contains contaminants. Moisture-laden CO_2, on the other hand, is highly corrosive, requiring pipe made from a corrosion-resistant alloy, or internal cladding with an alloy or continuous polymer coating. Some pipe made from corrosion-resistant alloys is several times more costly than carbon-manganese steel.

1.2.1 Economic aspects of pipeline CO_2 transport

Pipelines are mature technologies and are the most common method for transporting liquid and gaseous commodities on a regional as well as on an international scale. The technology and economics of pipeline transportation of CO_2 are very similar to those of natural gas, where pipeline transmission and distribution networks are well established.

Pipeline transportation is based on a pressure gradient induced by an initial compression of the commodity to nominal pressure (typically above 8 MPa for CO_2 to avoid two-phase flow regimes and to increase gas density). Pressure losses occurring during transport are adjusted by on-route compressor stations. Weymouth formulae are used to calculate the gas flow in pipelines. These equations exist in various modifications; Dahl and Osmundsen (2002, p. 10) introduces a flow equation as follows:

$$Q_{SC} = \left(\frac{T_{SC} \cdot \pi}{P_{SC} \cdot 8} 1.44 \cdot 10^{-3} \right) \left[\frac{\left(P_D^2 - P_S^2 \right) \cdot d^5 \cdot R}{MT_S \cdot Z_S \cdot L \cdot f} \right]^{0.5} \tag{3}$$

$$\text{with} \quad \frac{1}{\sqrt{f}} = 4 \log \frac{3.74}{e}. \tag{4}$$

McAllister (2005, p. 326) provides a simplified formula:

$$Q_{cf/d} = \frac{871 \cdot d_{inch}^{8/3} \sqrt{P_{D,psi}^2 - P_{S,psi}^2}}{\sqrt{l_{miles}}} \tag{5}$$

with the parameters defined in Box 2.

[3] A typical coal-fired 1,000 MW plant emits about 13 ktCO_2/d (Vallentin, 2007).

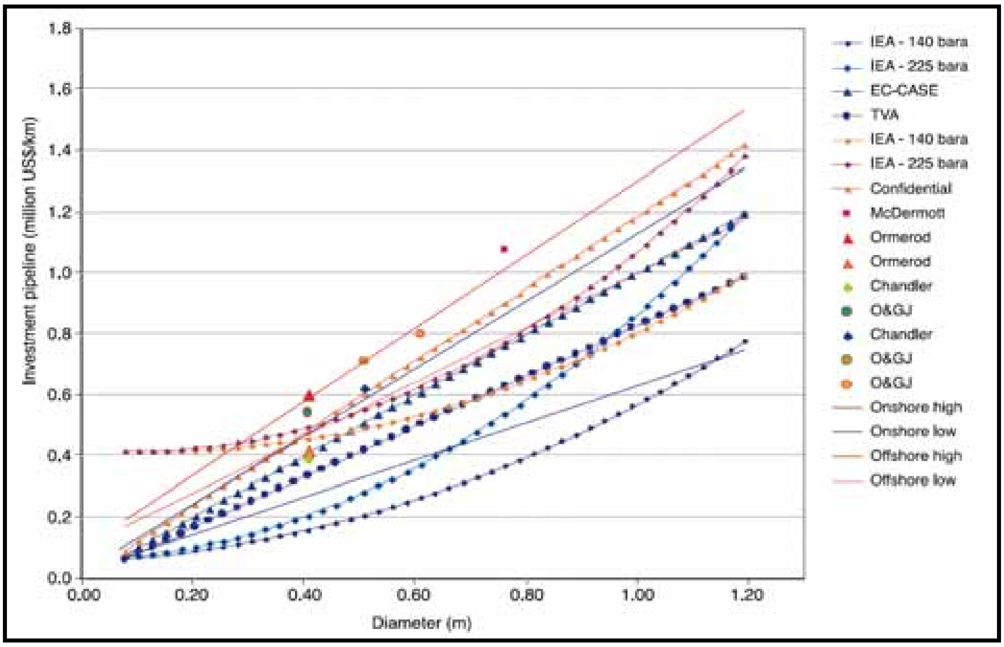
Box 2. Parameters in Equations (3) to (5)

R	Gas constant (8314.34 J/(kmol*K))
T_s	Surrounding temperature (K)
Z_s	Compressibility factor (0.6-0.7)
M	Molar mass (kg/kmol)
P_D	Outlet pressure (bar respectively psi)
P_S	Inlet pressure (bar respectively psi)
Q_{SC}	Flow under norm conditions (mn m³ per day)
$Q_{cf/d}$	Flow under norm conditions (cubic feet per day)
T_{SC}	Temperature under norm conditions (288.15K)
P_{SC}	Pressure under norm conditions (1.01325 bar)
d	Pipeline diameter (m respectively inch)
L	Pipeline length (m respectively miles)
f	Friction coefficient
e	Pipeline roughness

Pipeline capacity is dependent on inlet pressure, outlet pressure and a number of flow parameters, and increases disproportionally to the diameter (i.e. with an exponent of 2.65). That means significant scale economies can be realised. Besides this volume effect, an increasing diameter also produces a decrease in friction losses. At the same time, proportional to the mass flow the drop in pressure rises along a given distance and requires higher compressor capacities, which add to the variable costs of operation.

CO_2 pipelines representing a typical network industry are characterised by very high upfront investment costs. These are sunk in nature and vary between €0.2 mn (± 60%) and up to €1 mn (± 40%) per km for pipelines with a nominal diameter of 200 mm (1,200 mm), respectively (see Figure 7).

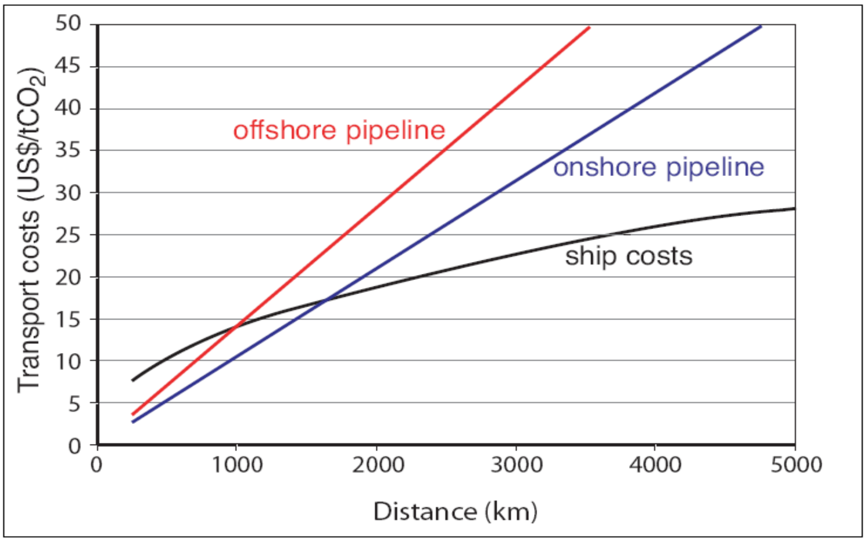
Figure 7. Pipeline investment cost estimates



Sources: IPCC (2005) (data derived from IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sarv, 2000; 2001a; 2001b; Ormerod, 1994; Chandler, 2000; O&GJ, 2000).

The cost advantage for the construction of parallel pipelines accounts for 20% of the construction of a second line within the same track and 30% for a third line. Compressor stations add about €7 mn to the investment costs for onshore stations and €14 mn for offshore stations. Environmental conditions, such as onshore versus offshore siting, geography and geology also affect transportation costs. In contrast, variable costs, primarily including expenditures for fuelling compressor stations, are mainly determined by the transportation distance and are comparatively low (Figure 8). In summary, CO_2 transportation costs vary between less than €1 and more than €20/tCO_2, being a function of the transportation distance (i.e. 100 to 1,500 km) and the CO_2 mass flow.

Figure 8. CO_2 transport cost comparison: On-/offshore pipeline vs. shipping transport



Notes: Pipeline costs are given for a mass flow of 6 MtCO_2/yr. Shipping costs include intermediate storage facilities, harbour fees, fuel costs, loading/unloading activities and additional costs for liquefaction compared with compression.

Source: IPCC (2005).

Due to the subadditivity of the cost function (i.e. CO_2 pipelines represent a natural monopoly), investment incentives in midstream transportation strongly depend on the potential regulations affecting siting, ownership structures (e.g. unbundling from upstream and downstream activities), access conditions for third parties, tariff calculations, etc.

Economic policy generally aims at establishing the highest possible degree of competition to maximise social welfare (the sum of consumer rent and producer rent). Effective competition prevails if the static and dynamic functions of competition are realised to a large extent and if there is no permanent and relevant market power by certain players (see also Viscusi et al., 2005 and Motta, 2004). Effective competition can be realised through *direct* competition in the market or through *potential* competition with companies that are potential entrants into the market (Bormann and Finsinger, 1999, p. 274). It is evident, however, that there can be no effective competition in the case of a natural monopoly. Where the service provided is a monopolistic bottleneck it must be regulated to avoid market power abuse.[4]

[4] Even in the absence of a natural monopoly, strategic behaviour may limit or even bar the emergence of effective competition, e.g. an incumbent network operator can set the price below the long-term marginal cost of the potential entrant, thus making it unprofitable to enter the market.

1.2.2 Point-to-point connections vs. a meshed network

The decision about point-to-point connections versus a network tends to be driven by the degree of dislocation of the expected large-scale sources and sinks and the related storage capacity. Dahowski et al. (2007) conclude that 77% of the total annual CO_2 captured from major North American sources can be stored in reservoirs directly underlying the sources, with a further 18% stored within 100 miles of additional sources. In such cases, point-to-point connections are the most efficient mode. Dahowski et al.'s conclusion also implies that the storage capacity of the sinks is well known and large enough for CO_2 injections over the life cycle of the plant.

Yet the decision changes when uncertainty enters into the equation. A meshed network connecting a larger number of storage sites and power plants enables risk mitigation for both plant and storage operators. With respect to regionally dispersed sources and sinks as well as long transport distances, the benefits of a meshed, interconnected pipeline network increase. Such a system is also favourable from a system security perspective and the cross-border transport and storage of CO_2.

Decision-making about the trade-offs between point-to-point and meshed CO_2 transport will be important for Europe. Transport over longer distances is likely to become significant for the implementation of CCTS, e.g. the southern European states lack geological formations suitable for storage on a larger scale. For countries like Germany, the Netherlands and the UK, where storage in the form of depleted natural gas fields or saline aquifers is available, backbone pipelines could offer an attractive alternative to onshore storage and the related NIMBY (not in my backyard) problem. In Germany, legislation on transport and onshore storage of CO_2 failed in 2009 because of public concerns about safety and decreased land valuations. The politically acceptable solution could be storage in saline formations or depleted fossil fuel reservoirs under the North Sea or Baltic Sea.

1.3 Downstream: CO_2 storage

Injection into reservoirs has existed for two decades, yet only a few operations offer permanent storage, such as Sleipner Field in Norway or In Salah, Algeria. Storage of CO_2 comes with a portfolio of technology options, not all of which are applicable in Europe for economic reasons or because of the scarcity of geological formations. Enhanced oil recovery (EOR), as well as enhanced gas recovery, depends on fields that still hold a significant quantity (60%) of the original oil in place. Alternatively, storage can take place in depleted fields, but without the monetary benefit of fossil fuel production. Mature oil and gas reservoirs that have held crude oil and natural gas for millions of years generally present a low risk of leakage. Even so, the paucity of global data on their number, location, condition, size and shape makes these sites problematical (in the Alberta Basin in western Canada, more than 300,000 oil and gas wells and in Texas more than 1,500,000 wells have been drilled (Celia et al., 2002)).

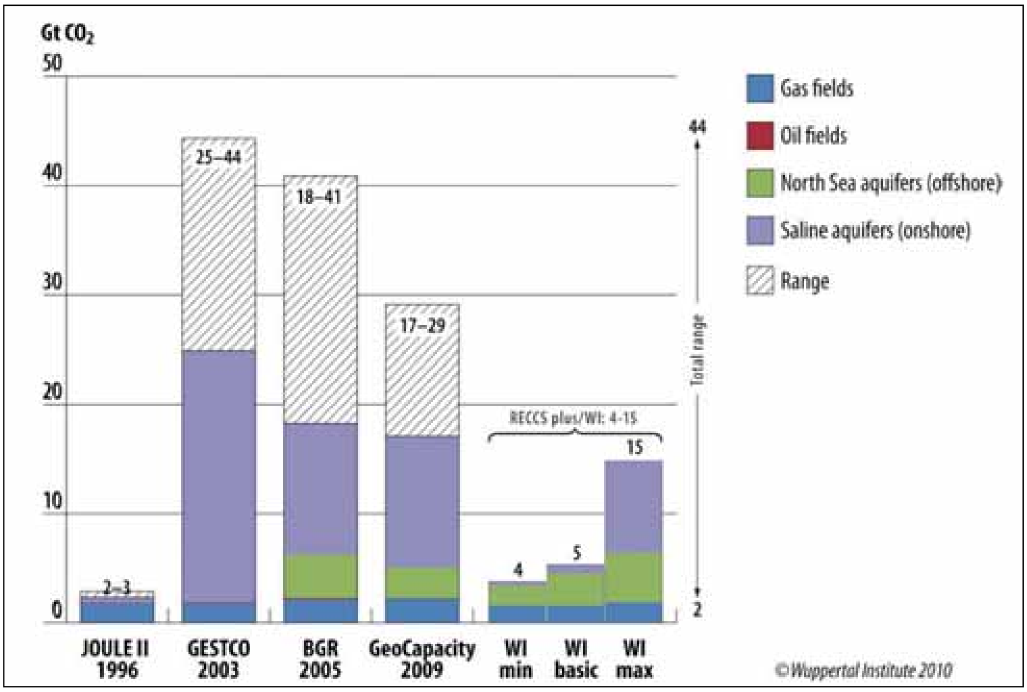
1.3.1 Enhanced oil recovery: The predominant application

Conventional oil production yields only a fraction of the original oil in place in a specific oil field. When this method is exhausted and the production rates are in decline, water (secondary recovery) and CO_2 floods (tertiary recovery), amongst other measures, may be used to increase production. The two techniques for CO_2 flooding are miscible and immiscible. In *miscible* CO_2 floods, CO_2 is pumped into the mature oil field above its minimum miscibility pressure (MMP) and acts as a solvent for the crude, improving its fluidity and increasing the pressure, thus pushing the oil towards the well. Since oil flows through the reservoir with less ease than the gas, the CO_2 may break through. Therefore, water and CO_2 are usually injected by turns in a so-called 'water alternating gas' process to create a barrier of water for both the CO_2 and oil. In *immiscible* CO_2 floods, the CO_2 is pumped underground at lower than MMP and pushes the oil towards the production wells. In both cases, a significant part of the CO_2 is transported back to the surface with the oil, but it is usually captured and recycled.

1.3.2 Storage potential

It is estimated that the world's saline aquifers could potentially hold 1,000 to 10,000 $GtCO_2$ (IPCC, 2005), but such estimates are unreliable (Figure 9). Uncertainty exists about the number of physical formations that could be used and about the individual potential they hold. Saline formations tend to have a lower degree of permeability than hydrocarbon-bearing formations, and studies are underway concerning hydraulic fracturing and other field practices to increase injectivity. Some reservoirs contain minerals that will react with injected CO_2 to form solid carbonates that can increase permanence but can also plug the formation in the immediate neighbourhood of an injection well. Research seeks injection techniques that promote advantageous mineralisation reactions.

Figure 9. Estimates of CO_2 storage capacity for Germany

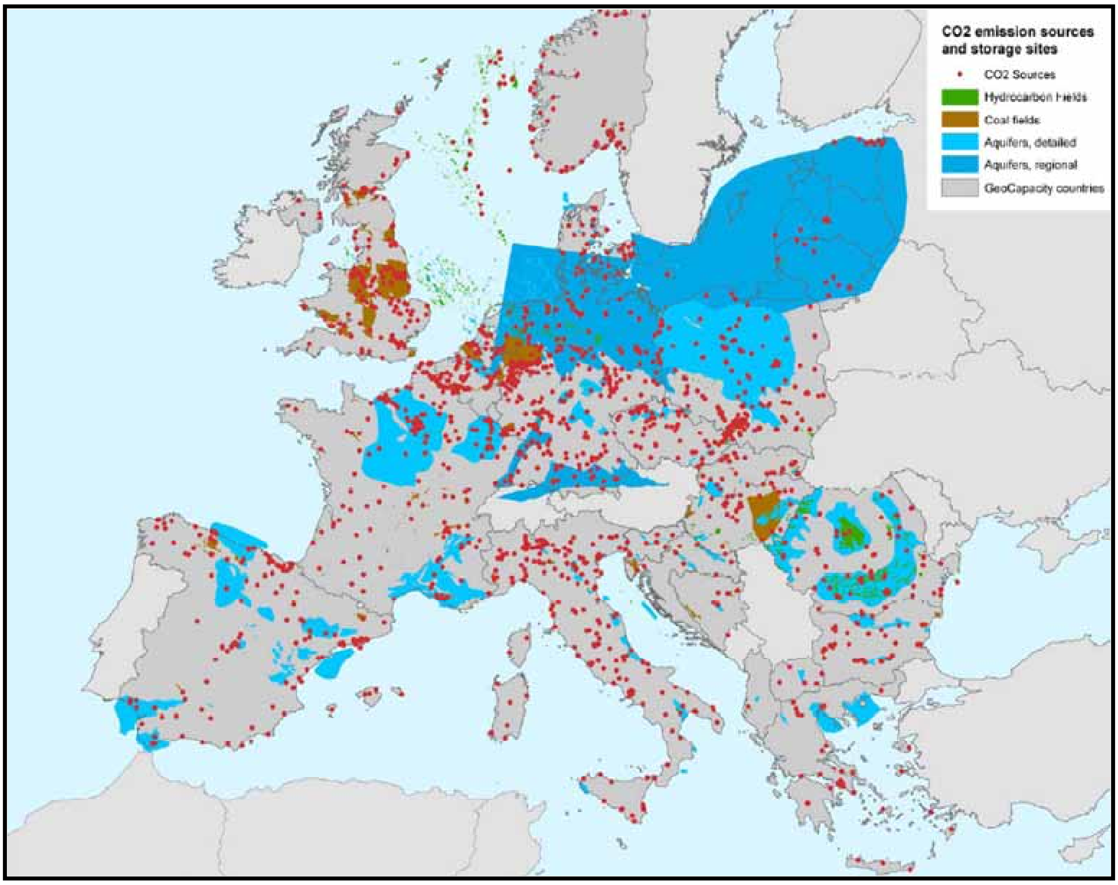


Source: Wuppertal Institute (2010).

Figure 10 shows estimations of the geographical distribution of CO_2 sinks and sources in Europe. Storage in saline aquifers appears to offer the greatest potential, followed by coal seams. Enhanced coal-bed methane (ECBM) recovery[5] is aimed at deep coal seams that cannot be exploited at reasonable cost. One barrier is that the swelling of coal after the CO_2 injection reduces permeability and thus the amount of CO_2 that can be injected.

[5] China is interested in ECBM because of the possible extraction of methane (natural gas) by injecting CO_2 into the coal seam (Vallentin, 2007).

Figure 10. Estimated CO_2 sinks and sources in Europe



Source: GeoCapacity (2009).

The Federal Institute for Geosciences and Natural Resources (BGR) estimates that the total annual storage potential in Germany is 50 to 75 $MtCO_2$. This corresponds to just around 20% of the emissions covered under the German EU Emissions Trading Scheme (ETS) and highlights the limitations of CCTS, especially if the observed trend tends to continue (Gerling, 2010).

1.3.3 Leakage and monitoring

The storage of CO_2 in geological formations requires sufficient permanence and monitoring. The IPCC (2005) estimates that up to 600 Gt of carbon can be stored by the end of this century. A 0.1% leakage rate means that 0.6 Gt of carbon would be released to the atmosphere from storage alone.

Some low level of leakage is acceptable, but must be monitored over a time horizon exceeding the planning horizons of most firms, hence making governmental intervention necessary. The European Commission proposes transferring liability to the public 20 years after site closure. A proposal for a German CCTS law suggests 30 years, only after long-term safety has been proven. Abrupt leakage could have negative impacts on the environment, ecosystems, the accounting of GHG inventories and public acceptance. Ironically the steps along the value chain that entail the least amount of uncertainty and risk from a technical point of view, transport and storage, are exposed to the highest levels of public awareness and rejection. There is rising concern that public rejection can form the most persistent barrier to the large-scale implantation of CCTS. Potential CCTS actors should focus on this point specifically as there remain only limited and expensive alternatives, such as seabed offshore storage.

2. International experiences: Great ambitions, but meagre results

2.1 Great ambitions: The IEA (2009) Blue Map scenario

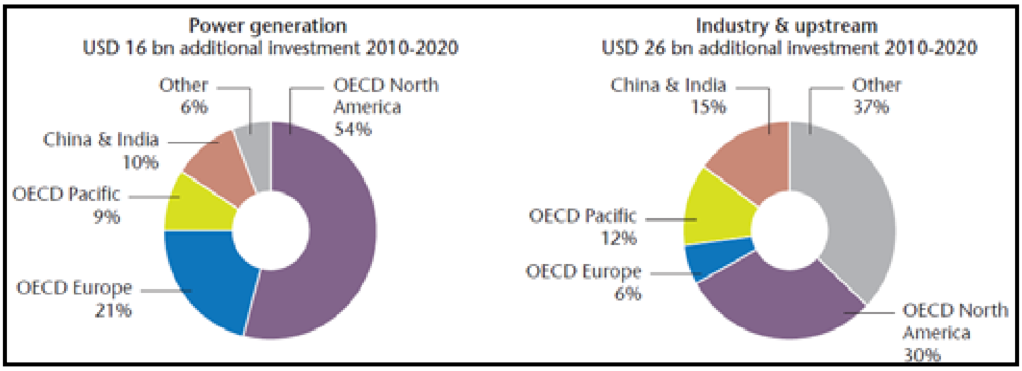
The IEA (2009) has published a roadmap with detailed milestones for the key developments in CCTS needed to achieve the overall goal of halving the annual CO_2 emissions of 2005 in 2050. Meeting the overall CO_2 reduction targets requires 3,400 projects worldwide until 2050, which altogether demand investments of US$3 trn – equivalent to 3% of the total expenditures needed to achieve the global emissions goal. About half of the projects would be undertaken in the power generation sector, 14% in the upstream sector and the remainder in the industrial sector. The demand for transportation facilities is estimated at 200,000-360,000 km of pipelines in 2050, mostly in North America, China and OECD Europe. In these regions a cumulated daily transportation capacity of 11.5-14.5 Mt is necessary for 2050. The demand for storage capacity will need to be met by the worldwide development of storage facilities accumulating 145 Gt CO_2 in 2050. On the technology side the goal requires the commercial availability of facilities with a capture rate of >85% for all types of fuel. Moreover, all capture systems working at efficiency levels of 45% and beyond must be equipped with capturing facilities and pulverised fuel ultra-supercritical (USC) boilers.

The IEA roadmap sets milestones for the short-term horizon. In line with announcements in 2008 by the G8 to develop 100 CCTS projects from 2010 to 2020, the roadmap calculates funding 10 projects annually until 2020, with half of the projects situated in North America (see Figure 11). Total direct and indirect investments in CCTS would be about US$200 bn by 2020. CCTS efforts will need to be incentivised especially in non-OECD countries. The required funding is estimated to be US$1-2 bn per year until 2020. The funding level for CCTS demonstration projects in OECD countries is recommended to rise to US$3.5-4 bn per year.

Each CCTS step has a list of requirements, e.g. at the capturing step a reduction of the power penalty through increased process efficiency, operating pressure and heat will be vital for further development of CCTS technology. To be in line with the roadmap, large-scale power plant applications must be approved by 2015. The roadmap also calculates a reduction in the capital cost of 10-12%. Geske and Herold (2010), however, find that by applying a real options approach, investment in CCTS is mainly driven by stable CO_2 prices and thermal efficiency improvements.

Storage exploration is seen as a precondition for pipeline construction efforts that are broadly deployed. The roadmap recommends publicly-funded exploration programmes that deliver reliable information on storage capacities accompanied by appropriate safety criteria and regulations before 2012. Developed storage capacity of 1.2 $GtCO_2$ will be required in 2020.

Figure 11. Additional investment needs for CCTS over the next ten years



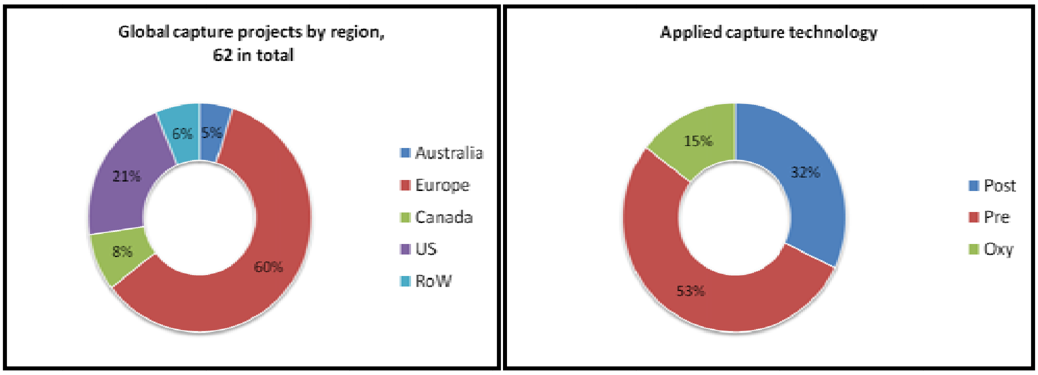
Source: IEA (2009).

2.2 Meagre overall results

The IEA roadmap highlights the tremendous need for global CCTS demonstration projects, which are unlikely to be realised by 2020. Of the 69 projects in our database, 7 are now operating, and their size (ranging from 5 to 35 MW_{th}) qualifies them solely as pilot plants (see Appendix 4). Amongst a number of announced projects, few are in the planning or construction start-up phases. Indeed, there have been delays in planning or construction for most of the other 61 projects. Therefore, it is critical to distinguish between proposed projects and those likely to be realised in the mid-term. Section 4.2.1.1 and Appendix 2 summarise the global demonstration projects that will receive public funding and thus have a certain probability of realisation if they meet the milestones in the planning process. Not all will test the technology for power generation, e.g. the majority of the Canadian projects focus on CO_2 storage (enhanced hydrocarbon recovery).

Under the assumption that all of the projects in our database will be realised by 2020 there is still a gap of 31 projects in order to achieve the IEA's blue map scenario. We find that only Europe can reach the IEA forecast by 2020 given the number of announced projects (see Figure 12). The IEA scenario requires global investment of US$57 bn until 2020. Governments have already committed about US$13.5-16 bn, depending on the revenues from EU emission allowances. It remains to be seen whether this money will be able to jumpstart CCTS development.

Figure 12. Regional distribution of announced CO_2 capture projects and technologies



Source: Own illustration.

2.3 The US CO_2 pipeline network

The US is sometimes cited as a benchmark for Europe. Hence we add some empirical experience of the development of CO_2 transportation in the US. The case study nonetheless shows that absent certain economic, technical and institutional factors, Europe is unlikely to follow the US. In reaction to the oil crisis in the 1970s, the US government began to promote enhanced fossil fuel recovery and in 1991, an Internal Revenue Code (§43) EOR tax credit went into effect for three general kinds of qualified costs: tangible property, intangible drilling and development costs, and tertiary injectants. In 2006, the 15% tax credit was phased out due to high oil prices (Jones, 2007).

The first project utilising CO_2 miscible floods was the SACROC unit in the Permian Basin in Texas. From January 1972, it accepted CO_2 from four gas-processing plants delivered via the Canyon Reef Carriers pipeline. As the supply from anthropogenic sources did not suffice, natural reservoirs, namely the McElmo Dome in Colorado and the Bravo Dome in New Mexico, were tapped and their CO_2 transported to the Permian Basin via the Cortez (808 km) and Bravo

(351 km) pipelines (see Figure 13). Other mature oil fields were gradually connected to create a large cluster of CO_2 EOR operations in the Permian Basin. Today, the major sources are the McElmo Dome and Doe Canyon (966 MMcfd) in Colorado, Bravo Dome (290 MMcfd) in New Mexico and Sheep Mountain (40 MMcfd) in Colorado, and several natural gas processing plants to the south of the Permian Basin that connect via the Val Verde Pipeline (75 MMcfd), for a total of 1,371 MMcfd, or 26.6 Mt/a (see Moritis, 2008 and Table 6). CO_2 availability limits the expansion of EOR operations in the basin and several companies are seeking to increase the availability of CO_2 with new pipelines.

Naturally occurring CO_2 resources are usually discovered when prospecting for natural gas. To produce the CO_2, wells are drilled as well as additional installations for compression, dehydration and cooling to transform the gas into marketable condition. The development of a natural CO_2 source thus does not much differ from developing a natural gas field. The cost structure of CO_2 production from natural sources is dominated by the capital expenditures for exploration and the production wells, and the relatively low cost of operation (i.e. the cost of energy for the conditioning facilities and the compressors and for safety measures if the installations are in a populated area).

According to Kinder Morgan (2009, pp. 6 and 71), US$290 mn has been spent to develop the Doe Canyon Deep Unit and expand the McElmo Dome Unit and Cortez Pipeline – US$90 mn of which was spent on drilling and installations at Doe Canyon field (delivering 120 MMcfd). The total increase of CO_2 production capacity through the investments is 300 MMcfd (about 5.8 Mt/a).

The other major operations in North America are the Weyburn CO_2 Monitoring and Storage Project, which captures about 2.9 Mt of CO_2 annually from a coal gasification plant in North Dakota and transports it 330 km through the Souris Valley Pipeline to mature oil fields in Saskatchewan, and the EOR operations fed by CO_2 from the Jackson Dome in Mississippi and from projects in Wyoming and Oklahoma. US oil production from CO_2 EOR (both miscible and immiscible) is approximately 250,000 bbl/d, or 5% of US domestic production. For a detailed case study of the Kinder Morgan pipeline operation, see Appendix 3.

Figure 13. US CO_2 transmission network

Source: European Energy Forum (2010).

Table 6. Major CO_2 pipelines in the US used for EOR operations

No.	Name	Start of operation	Country	CO_2 source	Length (km)	Location
1	Cortez Pipeline	1984	US	Geological	808	Denver City Hub, Texas
2	McElmo Creek Pipeline	–	US	Geological	64	McElmo Creek Unit, Utah
3	Bravo Pipeline	1984	US	Geological	351	Denver City Hub, Texas
4	Transpetco/Bravo Pipeline	1996	US	Geological	193	Postle Field, Oklahoma
5	Sheep Mountain (Northern)	1972	US	Geological	296	Denver City Hub, Texas; via Bravo Dome
6	Sheep Mountain (Southern)	1972	US	Geological	360	Denver City Hub, Texas
7	Central Basin Pipeline	–	US	–	225	–
8	Este Pipeline	–	US	Geological	192	Salt Creek Terminus
9	Slaughter Pipeline	1994	US	Geological	64	Slaughter field
10	West Texas Pipeline	–	US	Geological	204	Hobbs Field, Keystone Field, Two Freds field
11	Llano Lateral	–	US	Geological	85	Vauum Unit, Maljamar, C. Vac
12	Canyon Reef Carriers Pipeline	1972	US	Industrial	225	SARCO field
13	Val Verde Pipeline	1998	US	Industrial	132	SARCO field
14	North East Jackson Dome Pipeline	1985	US	Geological	295	Little Creek field
15	Free State Pipeline	2006	US	Geological	138	Eucutta, Soso, Martinville and Heidelberg field, Mississippi
16	Delta Pipeline	2008	US	Geological	50	Tinsley field
17	Delta Pipeline extension	2009	US	Geological	109	Delhi field
18	Green Pipeline	2010	US	Various	515	Hastings field, Texas
19	Weyburn/Souris Valley Pipeline	2000	US/CAN	Industrial	330	Weyburn field, Saskatchewan

Sources: Various publicly available data.

2.4 Other international experiences and lessons for Europe

Snøhvit and In Salah are the only projects where CO_2 is sequestered due to the tax on the CO_2 content of natural gas (see Table 7). The other major pipelines deliver CO_2 for application in secondary or tertiary oil recovery. Four pipelines transport CO_2 from industrial sources – gas processing and synfuel plants or a natural gas liquefaction facility. The other 15 pipelines are used for CO_2 from geological sources. Although insufficient data limit researchers' ability to understand the general structure of the sector, data on CO_2 volumes, origins and participants for several recent projects are available, possibly because of increased public awareness of climate change and the growing interest in EOR operations.

Table 7. Major CO_2 pipelines elsewhere in the world

No.	Name of the pipeline	Start of operation	Country	CO_2 source	CO_2 sink	Length (km)	Location
1	Bati Raman	1983	Turkey	Geological	EOR	90	Bati Raman field
2	Recôncavo	1987	Brazil	Industrial	EOR	183	Araçás field, Recôncavo Basin
3	In Salah	2004	Algeria	Natural gas processing	Aquifer	14	In Salah field
4	Snøhvit	2007	Norway	Natural gas processing	Aquifer	160 (offshore)	Snøhvit field, Barents Sea

Sources: Various publicly available data.

Europe's CO_2 pipeline network will differ substantially from that in the US. First, the positive experience with CO_2 pipeline development is based upon a different business model (EOR) without the objectives of large-scale carbon capture and long-term storage of most of the carbon. The 40 mn tonnes transported and stored[6] in the US do not approach what is expected should CCTS become a mature and widely applied technology. This volume equals roughly 10% of today's emissions from Germany's electricity sector. Nonetheless, European allocation of possible large-scale CO_2 sources coupled with the increased need for suitable storage will require a well-designed network with large backbone pipelines.

As we have noted, CO_2 production in a carbon-constrained world is influenced by economic incentives set by carbon taxes, permits or emission standards. It does not necessarily imply a constant use of the capture unit in plants, as shown by Geske and Herold (2010). Still, an irregular CO_2 flow will add to the complexity and costs of the transport and storage infrastructure.

Incentives exist to encourage site operators to inject less than the maximum rate or to renegotiate storage fees after a pipeline is built. Low-cost storage sites, i.e. depleted oil or gas fields, are scarce in most European countries; thus, it is expected that average storage costs will increase with the quantity of CO_2 injected and more use of expensive sites. Site operators will hold the upper hand when negotiations occur all along the CCTS value chain, particularly if the operator is not the pipeline owner – since in this case the pipeline owner assumes the upfront investment costs for the pipeline, relying on a steady stream of CO_2.

3. Modelling future CO_2 transport infrastructure

3.1 Model description

Mendelevitch et al. (2010) introduce a mixed integer, multi-period, cost-optimising CCTS network model to analyse the future potential of the technology for CO_2 reduction at the European level. It incorporates endogenous decisions about capture, pipeline and storage investments, and ejection and flow quantities based on given costs, certificate prices, storage capacities and point source emissions.

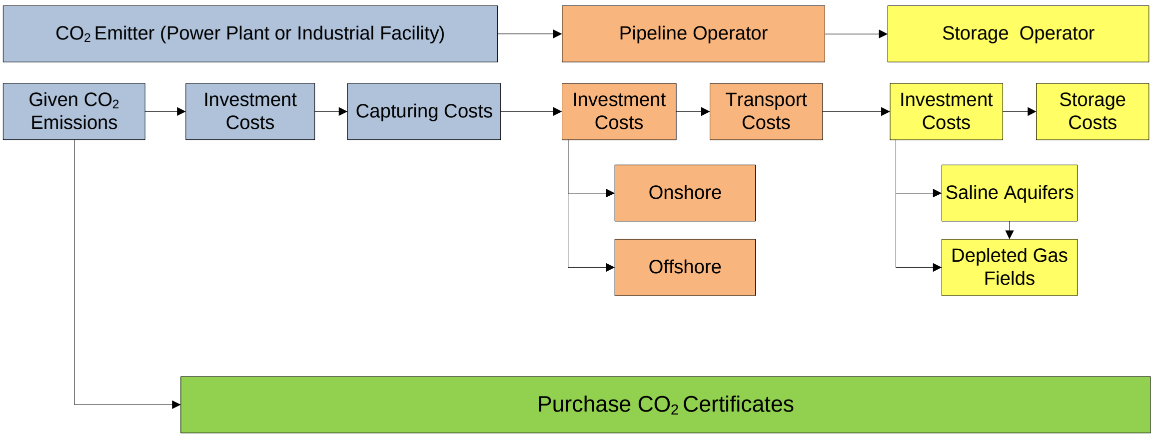
[6] Under normal conditions, only about 30% of the injected CO_2 remains underground. The rest is brought up with the oil, and then separated and re-injected.

In the model, sources and sinks are aggregated to nodes according to their geographical position and pipelines are constructed between either neighbouring or diagonal nodes. The distance between two neighbouring nodes can be arbitrary, making CCTSMOD scalable to Europe-wide levels. Economies of scale are implemented by discrete pipeline diameters with respective capacities and costs.

Figure 14 illustrates the development of CCTSMOD based on the CO_2 disposal chain. A producer must decide whether to release carbon into the atmosphere or store it through CCTS. The decision will be based solely on the price for CO_2 certificates and the investment costs for the capture unit, the pipeline and the storage facilities. The model runs in five-year periods starting in 2005 and ending in 2060. Capacity extensions can be used in the period after construction (true for all types of investments in the model).

A single omniscient and rational decision-maker is assumed. For the mathematical formulation of the cost minimisation problem please refer to Mendelevitch et al. (2010).

Figure 14. Decision tree for the CO_2 disposal chain of the CCTSMOD



Source: Own illustration.

3.2 Data

Comprehensive data are compiled for each step of the CCTS chain. For existing point sources in the industry and energy sector, data on annual emissions, capacity and location are taken from the "European Pollutant Release and Transfer Register" (EEA, 2007). Investment costs are defined as the additional technology costs for the capturing facility. For the transportation step we focus on pipeline transport as the most practicable option for Europe (IPCC, 2005). Pipeline capacity, derived from the IEA study on *CO_2 Capture and Storage* (IEA, 2008), provides a relationship between pipeline diameters and the respective possible flows per year. Three different kinds of storage sites represent the most promising options for long-term sequestration with regard to static range and availability in Europe:[7] onshore and offshore saline aquifers and depleted gas fields. The locations and data on storage volumes are based on data from the GeoCapacity (2009) project.

[7] Data for the following countries are included: Austria, Belgium, Bulgaria, Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.

3.3 CCTSMOD scenarios

Total subsurface storage potential for CO_2 exhibits much ambiguity because of a lack of high-resolution data (GeoCapacity, 2009), and as a result of different calculation methods (Wuppertal Institute, 2010) the estimations vary significantly. For this paper the storage potentials for Europe are taken from the GeoCapacity (2009) project. Three different storage potentials are defined:

- 'GeoCapacity', which is the estimation presented by the GeoCapacity project as the first approximations for the real storage potentials (100 Gt for Europe);
- 'GeoCapacity conservative', which is a conservative estimation of the storage potential, specifically accounting for a high level of uncertainty about the storage volumes of saline aquifers (50 Gt for Europe); and
- 'very low storage potential', more specifically in accordance with the prolonged decrease of storage potential estimations in recent studies (Höller, 2010), we assume an additional decrease of 50% (25 Gt for Europe).

The future development of the CO_2 certificate price in Europe is another economic and political uncertainty influencing CCTS deployment. We implement various linear CO_2 certificate price paths to examine the volatility of CCTS to CO_2 certificate price developments.

Rapid and broad deployment of CCTS technology will greatly depend on the public's opinion of CO_2 storage. For example, opposition to onshore storage could delay projects indefinitely or result in an abundance of alternative proposals akin to the experience of RWE's storage project in Husum. For these reasons, we include a study of the impacts upon public opinion of a scenario in which onshore storage is banned (see Table 8).

Table 8. Overview of scenario definitions

Scenario	**Geological storage potential**	**CO_2 certificate price in 2050 (€/tCO_2)**	**Public acceptance**
BAU (business as usual)	GeoCapacity (100 Gt for Europe)	43	Onshore + offshore
Low CO_2 certificate price	GeoCapacity (100 Gt for Europe)	31	Onshore + offshore
High CO_2 certificate price	GeoCapacity (100 Gt for Europe)	55	Onshore + offshore
Off 55	GeoCapacity (100 Gt for Europe)	55	Offshore storage only
Off 120	GeoCapacity (100 Gt for Europe)	120	Offshore storage only
Off 100	GeoCapacity (100 Gt for Europe)	100	Offshore storage only
Conservative storage potential	GeoCapacity conservative (50 Gt for Europe)	43	Onshore + offshore
Low storage potential	50% of GeoCapacity conservative (25 Gt for Europe)	43	Onshore + offshore

Source: Mendelevitch et al. (2010).

3.4 Scenario comparisons and interpretation

The BAU scenario and the Off 120 scenario exhibit similar annual storage rates in 2050, but deviate in the underlying infrastructure (Table 9 and Figures 15 and 16). Whilst in the BAU scenario less than 3,000 km of network are sufficient to connect sources and storage sites, the network is more than five times longer in the Off 120 scenario. The same industry accounts for 54% of total CO_2 storage by 2050 in the BAU scenario and 47% in the Off 120 scenario. The BAU scenario is characterised by short regional networks, whilst the Off 120 scenario has an integrated network that spans most of Western Europe. A comparison of the pipeline routing in both scenarios indicates that early, integrated infrastructure planning can realise economies of scale, e.g. in northern France and the Rhine area. Finally, in the BAU scenario, CO_2 streams split off into a southern stream leading to nearby sites in France and northern Germany, but in the Off 120 scenario they combine into one broad stream leading to German offshore storage.

Table 9. Overview of scenario results

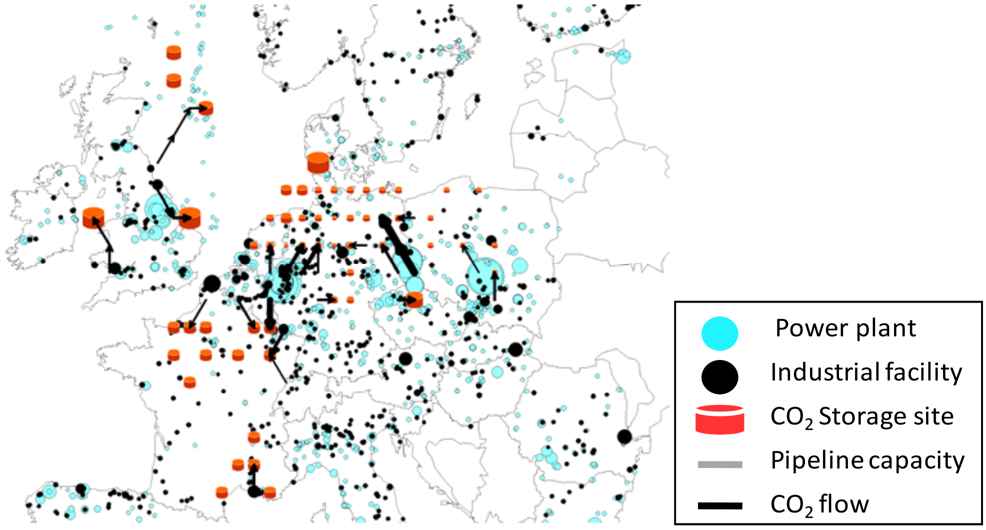
Scenario	**CO_2 price in 2050 (€/tCO_2)**	**CO_2 stored via CCTS in 2050 (%)**	**Annual storage rate exceeds 100 MtCO_2/a***	**Pipeline infra-structure longer than 1,200 km***	**Infra-structure length in 2050 (km)**	**Share of CO_2 from industry (%)**
On+off 55	55	48.6	2020	2020	13,359	40.7
BAU	43	19.4	2020	2020	2,897	54.0
On+off 31	31	3.9	2045	–	–	89.4
Conservative storage potential	43	13.5	2025	2025	1,333	60.6
Low storage potential	43	5.6	2035	2035	–	66.8
Off 55	55	8.2	2025	2025	1,490	68.1
Off 100	100	14.0	2020	2025	3,419	55.5
Off 120	120	24.7	2020	2025	15,889	47.2

* For comparison with IEA roadmap targets

Source: Mendelevitch et al. (2010).

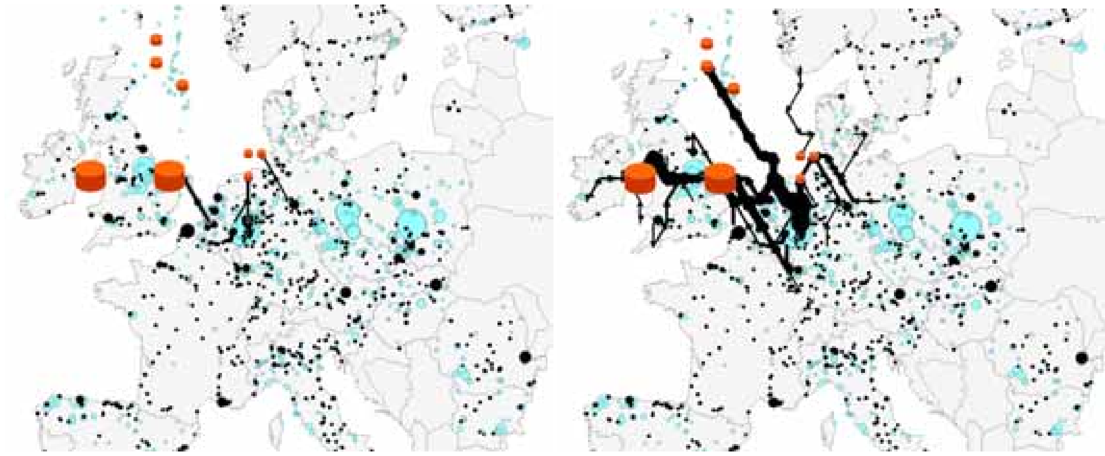
The results indicate that CCTS can theoretically contribute to the decarbonisation of Europe's energy and industry sectors. This requires a CO_2 certificate price rising to €55/tCO_2 in 2050, and sufficient CO_2 storage capacity available for both on- and offshore sites. Yet, CCTS deployment is highest in CO_2-intensive industries where emissions cannot be avoided by fuel switching or alternative production processes. In all scenarios, the importance of the industrial sector as a first-mover to induce the deployment of CCTS is highlighted. By contrast, a decrease of available storage capacity or a more moderate increase in CO_2 prices will significantly reduce the role of CCTS as a CO_2 mitigation technology, especially in the energy sector. Continued public resistance to onshore CO_2 storage can only be overcome by constructing expensive offshore storage. Under this restriction, reaching the same levels of CCTS penetration will require doubling the number of CO_2 certificates issued.

Figure 15. BAU: CCTS infrastructure in 2050



Source: Mendelevitch et al. (2010).

Figure 16. Offshore 120: CCTS infrastructure in 2020 (left) and 2050 (right)



Source: Mendelevitch et al. (2010).

4. Incentivising CCTS at the European level

Innovations do not fall like manna from heaven, nor do they enter a market by themselves. They require dedicated efforts in every technological phase (research, demonstration, deployment and diffusion) to successfully introduce the proper technology. We suggest that governments should support this process by designing instruments that overcome barriers.

4.1 Market barriers

European energy markets are characterised by significant market distortions, a limited number of players and energy policies that support standard fossil fuel technologies in the face of the looming problem of GHG and other externalities. Despite ongoing liberalisation, the industry is still highly regulated, which is troubling since some regulators can prevent firms (and society) from reaping the full benefits of successful innovation. Innovation and the diffusion of new technologies respond to the uncertainties that arise from incomplete information. For example, firms involved in R&D often encounter scepticism from potential investors demanding higher risk premiums. In turn, this could result in illiquid capital markets for funding the needed technological developments (Jaffe et al., 2005).

4.2 Shortcomings of the European Emissions Trading Scheme

According to Jaffe et al. (2005), "market failures associated with environmental pollution interact with market failures associated with the innovation and diffusion of new technologies". The objective of the EU ETS is often associated with two targets: first, to limit emissions in an efficient way amongst all sectors and economies, and second, to promote technological change in GHG-intensive sectors. We argue that the second objective cannot be achieved by the ETS alone and that additional policy instruments are required to promote technological change at the desired scale and speed defined by the IEA roadmap.

The short history of the EU ETS shows that the scheme is unable to create incentives for innovation and investment in large-scale technologies such as CCTS. Its chief shortcomings – short-term trading periods, a grandfathered over-allocation and national allocation instead of a Europe-wide allocation plan – produce low but volatile market prices (Groenenberg and de Coninck, 2008). Thus, firms avoid investment in high-risk, high-cost long-term technology. Raising carbon prices to a level that induces technological change in the short term is politically unlikely. Therefore, thought should be given to additional instruments to compensate for the shortcomings of the EU ETS.

4.2.1 Investment support at the European level

Given the large investment costs for CCTS technology (as shown earlier in Figure 4), capital markets may fail to finance projects with a high inherent risk of failure. The funding of demonstration projects places governments in a strong position because it increases influence over technology decisions and ensures that the knowledge gained in the demonstration projects is spread (i.e. leading to rapid diffusion). Nevertheless, governments are often ill informed when it comes to selecting the appropriate project or technology and inadvertently dismiss the most promising concepts. Under the European Economic Recovery Plan, four of six publicly-funded CCTS projects are based on post-combustion capture technology (as discussed below). With the highest level of commercial maturity this might be justified. Yet, one could also argue that scaling up a proven technology is best left to industry, and the focus should instead be on innovative capture technologies.

Investment subsidies can be used to incentivise innovations in various stages of technological maturity, but are more suitable for initial demonstration. Investment support for CCTS alone may fail to incentivise investment on the scale desired. For example, where renewable energy technologies assume high upfront investment and low variable costs, CCTS significantly lowers plant efficiency. Additional instruments may therefore be needed to compensate for low carbon prices. As direct investment support places a relatively high cost burden on governments, the risk of neglecting other promising low-carbon technologies remains (Groenenberg and de Coninck, 2008).

A survey of international CCTS projects and their subsidies is in Appendix 2.

4.2.1.1 The European Energy Programme for Recovery

The European Energy Programme for Recovery (EEPR) is part of the European Economic Recovery Plan presented by the European Commission on 26 November 2008. The EEPR has almost €4 bn to co-finance specific energy projects, especially in the field of gas and electricity interconnections (€2.365 bn), offshore wind energy (€0.565 bn), and carbon capture and storage (€.05 bn). The funding cannot exceed 80% of the eligible costs (MEMO/09/543, European Commission, 2009). In December 2009 the European Commission chose six carbon capture and storage projects from amongst twelve proposals. Five of the six will receive an initial subsidy of €180 mn, which will be matched by the respective national governments. One project will receive €100 mn (Reuters, 2010a). The criteria for the decision-making entailed that projects had to demonstrate the ability to capture at least 80% of produced CO_2 and the ability to transport and geologically store CO_2 safely underground. In power installations, CO_2 capture had to be demonstrated on an installation of at least 250 MW capacity.

The proposed projects had to be able to reach the investment stage by the end of 2010 and the full financial package (own financial contribution, other financing sources) had to be sound, with all necessary permits to be obtained shortly. The six projects selected are described below.

- **Jänschwalde/Germany** (Leader: Vattenfall; EU funding: €180 mn). Based on an existing 3,000 MW coal plant, the project will seek to demonstrate oxy-fuel and post-combustion technology. All storage options are to be investigated in detail. Storage could be critical, as it is unclear whether permission for CO_2 storage can be obtained (German legislation allows for either the use of geothermal heat or carbon storage). The construction of a new CCTS boiler is to start in 2011.
- **Porto-Tolle/Italy** (Leader: Enel Ingegneria e Innovazione S.p.A.; EU funding: €100 mn; total cost estimated at €800 mn). Integration with a new 660 MW coal-fired plant will test post-combustion technology in a unit corresponding to 250 MW output. The project will entail storage in an offshore saline aquifer 200 km from the plant.
- **Rotterdam/Netherlands** (Leader: Maasvlakte J.V./E.ON Benelux and Electrabel; EU funding: €180 mn; total cost estimated at €1.2 bn). Part of the Rotterdam Climate Initiative, this project will test post-combustion technology on a scale of 250 MW. Storage will be arranged in a depleted offshore gas field 25 km from the plant.
- **Belchatow/Poland** (Leader: PGE EBSA; EU funding: €180 mn). A 250 MW post-combustion capture unit will demonstrate the entire CCTS value chain. Three different saline aquifer sites are to be investigated (61 km, 72 km and 140 km from the plant). The operation of a full-scale 850 MW demonstration plant is scheduled in 2015.
- **Compostilla/Spain** (Leader: ENDESA Generacion S.A.; EU funding: €180 mn and €280-450 mn in the form of EU emission allowances). A 30 MW pilot plant will be scaled to a 320 MW demonstration plant by 2015, testing oxy-fuel and fluidised bed technology. Storage is to be arranged in a saline aquifer 100 km from the plant.
- **Hatfield/United Kingdom** (Leader: Powerfuel Power Ltd.; EU funding: €180 m; total costs for an IGCC unit estimated at £800 mn). Forming part of the Yorkshire Forward Initiative, a 900 MW plant will demonstrate IGCC. Storage is to be arranged in an offshore gas field 175 km from the plant.

Four projects are on a reserve list should those listed above fail the criteria: Huerth in Germany, Eemshaven in the Netherlands, and Kingsnorth and Longannet in the UK.

4.2.1.2 Use of 300 million CO_2 certificates for CCTS and renewables

On 2 February 2010 EU member states agreed on the use of the revenues generated by sales of 300 mn CO_2 certificates from the EU ETS new entrants reserve. The sales finance CCTS demonstration projects (200 mn certificates) and innovative renewable-energy technologies (100 mn certificates). The agreement also proposes to fund eight CCTS projects, with at least one but no more than three of each technology concept. Storage in hydrocarbon reservoirs must be demonstrated in one project and storage in aquifers in at least three. Depending on the certificate price, up to €6 bn could become available for CCTS.

Project selection will take place in two rounds of requests for proposals, with funds covering 50% of the additional costs of the demonstration plant. The disbursement of cash to projects will occur annually, based on performance.

4.2.1.3 United Kingdom (tender approach)

In 2007 the UK government announced a competition to award £1 bn to fund a commercial-scale CCTS project by 2009. The requirements were to demonstrate the full chain of CCTS between 2011 and 2014, utilise sound engineering design, document the funding requested, be a minimum of 300 MW, and capture and store 90% of CO_2. The long-running competition discouraged firms from coming forward (Hazeldine, 2009) and only three projects were finally considered: RWE npower's new coal plant at Tilbury in Essex, E.ON's new coal plant at Kingsnorth in Kent, and Longannet (Scottish Power) at Fife in Scotland. The competition involved sealed bids so firms claimed they were unable to disclose information. RWE npower dropped out first, followed by E.ON. This left only Longannet, which has never met all of the criteria that the UK set when it announced the competition in 2007. To speed things up, the UK government has committed to helping fund up to four CCTS plants in the UK. The first – the competition winner – will be funded by the Treasury, but any further plants will be funded primarily from a levy on energy bills.[8]

4.2.2 Additional support instruments

A portfolio of additional instruments exists to support the research, development, demonstration and deployment process of innovative energy technologies. Even so, the effectiveness of different instruments to support a given technology strongly depends on the technology itself, the stage of maturity, the market, the legal and institutional framework, etc. The following additional instruments might be discussed to promote and accelerate the diffusion of CCTS:

- **A CCTS obligation** specifies the kind of abatement equipment or method to be used. Therefore, by definition a technology obligation prevents firms from selecting and using least-cost abatement methods. Obligations also come with the highest risk of technology lock-in, meaning that a technology in use will only be second best compared with an upcoming alternative. Due to the obligation, however, a major investment will have been undertaken in the past. Subsequently, switching would turn that into a sunk investment, thereby increasing the costs for the alternative, yet socially desired technology. To limit that risk, the CCTS technology should be mandatory only if a portfolio of capture technologies is proven. A CCTS obligation can also raise the system costs for CCTS by forcing electricity producers to apply the technology where there is insufficient storage capacity. Another option is mandating that all new power plants are capture-ready. This will increase construction costs only moderately, but will guarantee that more plants are compatible with mature CCTS technology in the future. Still, in the absence of a credible CO_2 price path, forcing utilities into a capture-ready option will only raise the costs of the standard plants but will not incentivise CCTS investment (Geske and Herold, 2010).
- **Portfolio standards** oblige consumers or retailers to source some percentage of their electricity from specific sources or fuels (Groenenberg and de Coninck, 2008). They are often combined with tradable permits, thus increasing flexibility and reducing compliance

[8] Newbery et al. (2009) provide a detailed proposal for how to structure the tendering process.

costs. A portfolio standard places all of the costs and risks upon producers who in turn pass the costs through to the end-users. In the UK, a renewable portfolio standard has proven less effective to promote investment in wind energy compared with feed-in tariff approaches elsewhere (Butler and Neuhoff, 2005). Portfolio standards set very strong incentives to cut costs and develop a technology, but at the risk of picking losers. We suggest it as an option when CCTS technology has reached a sufficient level of market maturity.

- **Feed-in tariffs or premia** guarantee either a fixed price or a market premium for CCTS-based electricity fed into the grid. Feed-in systems have proven effective in stimulating investment in renewable generation technologies, as evinced by the rapid expansion of wind generation in Denmark, Germany and Spain. Feed-in schemes are simple and transparent and can be adjusted according to political targets. They provide private investors with a reliable long-term prospect and have attracted impressive levels of investment in the renewable-energy technology sector (Groenenberg and de Coninck, 2008). To compensate for the risk of over- or undershooting a target, the tariff should be linked to a minimum or maximum level for the amount of low-carbon electricity compensated. Continuously downward adjustment of the tariff ensures pressure for further innovation and cost reduction. According to its design, a feed-in tariff assigns the cost burden to electricity consumers or taxpayers.

- **Public–private partnerships** may play a role in the development of the transport infrastructure. If individual players are unlikely to bear the risks and the costs of network development, CCTS transport becomes an example of the collective action problem (Groenenberg and de Coninck, 2008). According to Boeuf (2003), several issues must be resolved to minimise financial and societal risks during the design, construction and operation phases (European Commission, 2003) prior to establishing a viable partnership. The shortcomings of the public–private partnership approach include underestimation of construction and equipment costs, construction delays, the overestimation of revenues and the neglect of issues related to societal acceptance.

5. Conclusions and policy recommendations

This Working Document expands on earlier techno-economic analysis of the CCTS chain, initially carried out in the framework of the SECURE project. Our message, derived from technical analysis, modelling work and case study evidence, is clear: there is a high probability that coal will no longer be an essential element of the European energy supply, because the CCTS rollout will be delayed or never carried out. There is justified concern that the ambitious development plans in CCTS demonstration as outlined in the IEA Technology Roadmap over the next decade will not be met. This is based on a lack of determination by public authorities to overcome the significant obstacles inherent in the complexity of the CCTS chain, and the difficulties of the power sector in embracing a technology that challenges the business model of coal electrification. We identify obstacles at all stages of the value-added chain, which are highly uncertain technical processes and the costs of CO_2 capture, unresolved institutional and regulatory issues in CO_2 transportation, and a tight, regionally concentrated availability of storage sites. Increased public opposition to onshore storage will most likely necessitate offshore solutions. This will raise the costs and the technical complexity of the CCTS chain.

We therefore have the following recommendations:

- The potential contribution of CCTS to a decarbonised European electricity sector should be reconsidered given the new data available on CCTS costs, a better understanding of the complexity of the process chain and the reduced CO_2 storage potential. The idea that

CCTS could constitute an 'energy bridge' to a new, largely renewable-based energy system should be dismissed.

- Europe has an important role to play in keeping the technology options open and avoiding premature intellectual property appropriation. The EU's co-funded projects should make new knowledge widely available, and competition amongst projects be promoted that yields the highest chances of achieving technical progress (Newbery, et al., 2009).
- Money does not seem to play a significant role as a constraint to CCTS projects. The readily available billions of euros and dollars should be rapidly deployed. In cases where industry does not respond, the legal and regulatory framework should be readjusted and the level of incentives should be raised. In the absence of a credible CO_2 price path, forcing utilities into a capture-ready option will raise the costs of the standard plants but will not incentivise CCTS investment (Geske and Herold, 2010).
- The strong focus on the implementation of CCTS in the power sector observed in the past should be extended to industrial applications, which can be highly vulnerable to an abandonment of coal. Owing to a larger number of small emission sources, this will pose greater challenges to network development.
- The early planning of transport routes is of paramount importance should large-scale CCTS deployment be implemented. At least in this phase, the state will be needed as a major provider in the development of transportation infrastructure, including planning and siting.
- Construction and operation can be tendered to the private sector or carried out by state-owned network firms. Routing pipelines along existing networks can lower costs and, to a limited extent, public rejection. Thus, synergies with other energy network infrastructure (gas, electricity) should be considered.
- Future regulation should specify the allocation and financing principles as well as access for third parties. It is unlikely that the private sector has sufficient incentives for developing the network, given the political, regulatory, technical and economic uncertainties.
- If Europeans fail to fulfil their role as CCTS pioneers, new strategies for the global rollout of CCTS are needed. The inclusion of CCTS under the Clean Development Mechanism could help to bring the technology to the markets. Yet this would also imply outsourcing the potential risks associated with the technology.

List of abbreviations and symbols

BAU	Business as usual
bbl	Barrel
bcfd	Billion cubic feet per day
CCTS	Carbon capture, transport and storage
CO	Carbon monoxide
CO_2	Carbon dioxide
DOE	US Department of Energy
ECBM	Enhanced coal-bed methane recovery
EEPR	European Energy Programme for Recovery
EOR	Enhanced oil recovery
ETS	EU Emissions Trading Scheme
FERC	US Federal Energy Regulatory Commission
GHG	Greenhouse gas
$GtCO_2$	Gigatonnes of carbon dioxide
GW	Gigawatt
H_2	Hydrogen
ICC	Interstate Commerce Commission
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
IRCC	Integrated reformation combined cycle
ISCG	In-situ coal gasification
kt	Kilo tonnes (thousand tonnes)
kW	Kilowatt
Mcf	One thousand cubic feet
MEA	Monoethanolamin
MMcfd	Millions of cubic feet per day
MMP	Minimum miscibility pressure
MPa	Mega Pascal
Mt	Megatonnes (million tonnes)
MW	Megawatt
MWh	Megawatt hours
NGCC	Natural gas combined cycle
Nm^3	Normal cubic metre
NO_x	Nitrogen oxides
O_2	Oxygen
OECD	Organisation for Economic Cooperation and Development
O&M	Operating & maintenance
PC	Pulverised coal
SO_x	Sulphur oxides
Tcf	Tera cubic feet
th	Thermal
USC	Ultra supercritical

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Appendix 1. 2040 cost estimations for CCTS power plants

Table A1.1 Cost estimates for fossil fuel plants without CO_2 capture in 2020

Study		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)	Wuppertal Institute (2007)
Pulverised coal						
Efficiency	%	42.7	44	42	45.6	49
Investment	€/kW_{el}	1,425	1,086	1,085	870	950
O&M	€/kW,a	72.1	33	50	–	48.3
Electricity costs with CO_2[1)] penalty	€ct_{2000}/kWh_{el}	5.19	4.15	4.39	3.9	4.89
IGCC, hard coal						
Efficiency	%	43.1	46	47	49,=.4	50
Investment	€/kW_{el}	1,557	1,335	1,685	1,100	1,300
O&M	€/kW,a	59.3	37.1	57.5	–	53
Electricity costs with CO_2[1)] penalty	€ct_{2000}/kWh_{el}	5.21	4.48	5.18	4.2	5.46
NGCC						
Efficiency	%	53.6	59	58	58.6	60
Investment	€/kW_{el}	590	424	480	700	400
O&M	€/kW,a	23.3	14.8	37.3	–	34.1
Electricity costs with CO_2[1)] penalty	€ct_{2000}/kWh_{el}	4.97	4.35	4.71	5	4.94

[1)] €15/tCO_2

Source: Wuppertal Institute (2007), p. 153.

Table A1.2 Cost estimates for fossil fuel plants with CO_2 capture in 2020

Study		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)	Wuppertal Institute RECCS[2)] (2007)
Pulverised coal CCTS						
Efficiency	%	31	36	33.7	35.4	40
Investment	€/kW_{el}	2,385	1,823	1,880	1,470	1,750
O&M	€/kW,a	129	78	79.9	–	80
Capture rate	%	83.5	83.5	85	84.4	83.5
Electricity costs with CO_2[1), 3)] penalty	€ct_{2000}/kWh_{el}	8.06	6.29	6.48	5.78	6.13

Table A1.2 cont'd

IGCC, hard coal CCTS						
Efficiency	%	37	40	42,2	40,3	42
Investment	€/kW$_{el}$	2,011	1,733	2,375	1,720	2,000
O&M	€/kW,a	72	55	87.5	–	85
Capture rate	%	86	86.2	86.6	91.1	85.7
Electricity costs with CO_2 [1), 3)] penalty	€ct$_{2000}$/kWh$_{el}$	6.56	5.57	6.95	6.00	6.46
NGCC CCTS						
Efficiency	%	43.3	51.0	52.0	50.6	51
Investment	€/kW$_{el}$	1,125	850	890	1,170	900
O&M	€/kW,a	52.8	35	51.7	–	54
Capture rate	%	85.1	86.1	86.6	94.1	85.9
Electricity costs with CO_2 [1), 3)] penalty	€ct$_{2000}$/kWh$_{el}$	7.12	5.77	5.99	6.59	6.16

[1)] €15/tCO_2; [2)] Estimation for the German market; [3)] Without compression, transport or storage

Source: Wuppertal Institute (2007).

Table A1.3 Cost estimates for fossil fuel plants with CO_2 capture in 2040

		Pulverised coal[1)]		**IGCC**		**NGCC**	
		2020	**2040**	**2020**	**2040**	**2020**	**2040**
Without capture							
Efficiency	%	49	50	50	54	60	62
Investment	€/kW$_{el}$	950	900	1,300	1,200	400	400
CO_2 emissions	g/kWh$_{el}$	673	635	660	611	337	326
Electricity costs without CO_2 [1), 3)] penalty	€ct$_{2000}$/kWh$_{el}$	3.87	3.60	4.46	4.12	4.44	4.32
With capture							
Efficiency	%	40	44	42	46	51	55
Investment	€/kW$_{el}$	1,750	1,600	2,000	1,800	900	750
Capture rate	%	85.3	88.2	85.7	90.6	85.9	91.0
Additional fuel consumption	%	22.5	18.2	19.0	17.4	17.6	12.7
Electricity costs with CO_2 [1), 3)] penalty	€ct$_{2000}$/kWh$_{el}$	5.95	5.43	6.28	5.74	6.08	5.50

[1)] €15/tCO_2; [2)] Estimation for the German market; [3)] Without compression, transport or storage

Source: Wuppertal Institute (2007).

Appendix 2. International CCTS projects

Canada

Alberta has introduced legislation that provides the legal authority to administer the CAD$2 bn in provincial funding for four large-scale CCTS projects (Government of Alberta, 2010):

- **Project Pioneer** (Leader: TransAlta; funding: CAD$436 mn). This project utilises leading-edge technology to capture CO_2 for use in EOR in nearby conventional oil fields or stored 3 km underground. The project is expected to capture a million tonnes annually, beginning in 2015.
- **Shell Quest Project** (Leader: Shell, funding: CAD$745 mn). Starting from 2015, this project will capture and store 1.2 mn tonnes annually from Shell's Scotford upgrade and expansion near Fort Saskatchewan.
- **Alberta carbon trunk line** (Leader: Enhanced Energy Inc.; funding: CAD$495 mn). This project includes a 240 km pipeline to transport CO_2. Initial supplies will come from the Agrium Redwater Complex and (once built) the North West Upgrader, which will upgrade bitumen from Alberta's oilsands and transport the captured CO_2 to depleting conventional oilfields for use in EOR.
- **Swan Hills Synfuels** (Leader: Swan Hills Synfuels; funding: CAD$285 mn). This in-situ coal gasification (ISCG) project will access deep coal seams about 1,400 m below the surface traditionally considered too deep to mine. The wells will access the seams and be used to convert the coal underground into syngas to fuel high-efficiency power generation and the captured CO_2 will be used in EOR.

US

The US$2.4 bn mandated by the American Recovery and Reinvestment Act of 2009 will be used to expand and accelerate the commercial deployment of CCTS technology (Abercrombie, 2009). The initiative encompasses several main projects:

- **Clean Coal Power Initiative**. In this project, US$800 mn will be used to expand the DOE's Clean Coal Power Initiative, which provides government co-financing for new coal technologies that can help utilities cut sulphur, nitrogen and mercury pollutants from power plants. The funding will allow researchers broader CCTS commercial-scale experience by expanding the range of technologies, applications, fuels and geological formations that are tested (US DOE, 2009).
- **Industrial Carbon Capture and Storage**. The US$1.52 bn allocated to this project will be used for a two-part competitive solicitation for large-scale CCTS from industrial sources. The industrial sources include, but are not limited to, cement plants, chemical plants, refineries, steel and aluminium plants, manufacturing facilities, and petcoke-fired and other plants. The second part of the solicitation will include innovative concepts for beneficial reuse (CO_2 mineralisation, algae production, etc.) and CO_2 capture from the atmosphere. The remaining funding will be allocated to smaller projects.
- **FutureGen 2.0**. FutureGen is a public–private partnership seeking to build the first near-zero emissions power plant. Years after the FutureGen project in Illinois was initially proposed, and later abolished, FutureGen 2.0 will bring about US$1 bn in federal stimulus money to the state. The goal of the programme is to retrofit a coal-fired power

plant in Meredosia so that it can capture carbon emissions and store them underground. The FutureGen 2.0 project includes the following actions (FutureGen, 2010):

- An idle coal-fired power plant in Meredosia owned by Ameren Corp. will be retrofitted with advanced technology to cut emissions of carbon dioxide and other pollutants.
- The DOE and private-sector partners will establish a carbon-dioxide storage facility in Mattoon. The original plan, to build a coal-fired plant with carbon capture, has been scrapped.
- A 150-mile carbon-dioxide transportation pipeline will be built from the Meredosia facility to Mattoon for sequestration.

Australia

Australia allocated AUD$2.4 bn to partially fund carbon capture and storage; AUD$2 billion will be invested over nine years in the Carbon Capture and Storage Flagships programme. The projects are expected to comprise the development of a storage hub and support for a range of technologies to capture CO_2 from coal-fired power stations. It is hoped that along with the existing AUD$400 mn National Low Emissions Coal Initiative and the Co-operative Research Centre for Greenhouse Gas Technologies, the CCTS Institute and the Flagships programme will ensure that Australia continues to be a world leader in the development of clean coal technology (Australia Office of Energy). The following projects are suggested (Australian Government, 2009):

- **Wandoan**. This 334 MW IGCC coal-generation project aims at sequestering 2.5 $MtCO_2$ per year. It was chosen for further assessment because it is close to both an abundant supply of black coal and a storage site with good potential.
- **Zerogen**. The Zerogen 400 MW IGCC coal-generation project will seek to sequester 2 $MtCO_2$ per year. The project is near prospective geological storage formations that are under assessment.
- **Collie South West Hub**. With a view to sequestering 3.3 $MtCO_2$ per year from nearby industry, the Hub was chosen because it is near potentially suitable storage sites and a large source region for CO_2 capture – the industrial centres of Kwinana and Collie.
- **CarbonNet Hub**. With the goal of sequestering 3-5 $MtCO_2$ per year from nearby industry, CarbonNet was chosen because it is near potentially suitable onshore and offshore storage, as well as having the potential to bring together a range of CO_2 capture projects from a large industrial region.

Appendix 3. Case study: Kinder Morgan

Players along the value chain

The sector is characterised by a small number of private investors who typically operate the CO_2 sink and source and in many cases the midstream pipeline. As CO_2 is mainly taken from low-cost natural and some industrial sources in the absence of a carbon mitigation policy, the inability to store more (e.g. given low oil prices) simply implies closing the top of the reservoir or releasing CO_2 into the atmosphere. Thus, the pipeline and the CO_2 source together should be regarded as an extension of the crude oil exploration and production value chain.

US CO_2 market players face risks similar to those in the natural gas market. High capital expenditures and sunk costs are incurred when developing CO_2 fields and pipeline construction requires continuous cash flows from CO_2 production and pipeline operation. Producers of natural CO_2 cannot readily sell their gas to a random buyer, since the number of oil fields connected by CO_2 pipelines is limited and the start-up of a CO_2 flood requires technical preparation. EOR operators on the other hand depend on a steady supply of CO_2 to retain their oil production levels.

Such risks are addressed in the reviewed enhanced oil recovery applications by two means. The first is vertical integration. Most participants have an ownership interest and/or operate at least two of the three segments of the value chain. The companies own and/or operate the CO_2 source and the pipeline, or the pipeline and the oil field where the CO_2 is used or they are active on all three levels. The projects considered outside North America (Snøhvit in Norway and Bati Raman in Turkey) are fully integrated and all links of the value chain are owned by the same company. The second is long-term take-or-pay contracts, which are common to this sector. In all cases where contract or pricing information is accessible, the price of CO_2 is linked to an index of the oil price (e.g. West Texas Intermediate). Contracts are several years in length and obligate the seller to purchase a specified minimum quantity of CO_2 in a given period or to reimburse the buyer for the difference (see also Resolute Energy Corporation, 2006 and 2007). According to the IPCC (2005, p. 262) the CO_2 price (in US$ per thousand cubic feet) equals 3.6% of the oil price (in US$ per barrel) or about $2.50/Mcf ($47/tonne) at current oil price levels ($70/bbl). It is further estimated that 6 to 10 Mcf of CO_2 are needed to produce one incremental barrel of oil, so the cost of CO_2 in EOR operations constitutes about 20 to 35% of the sales revenue and is the most expensive part of CO_2 flood operation.

Kinder Morgan

According to Kinder Morgan (KM) (2010), the firm

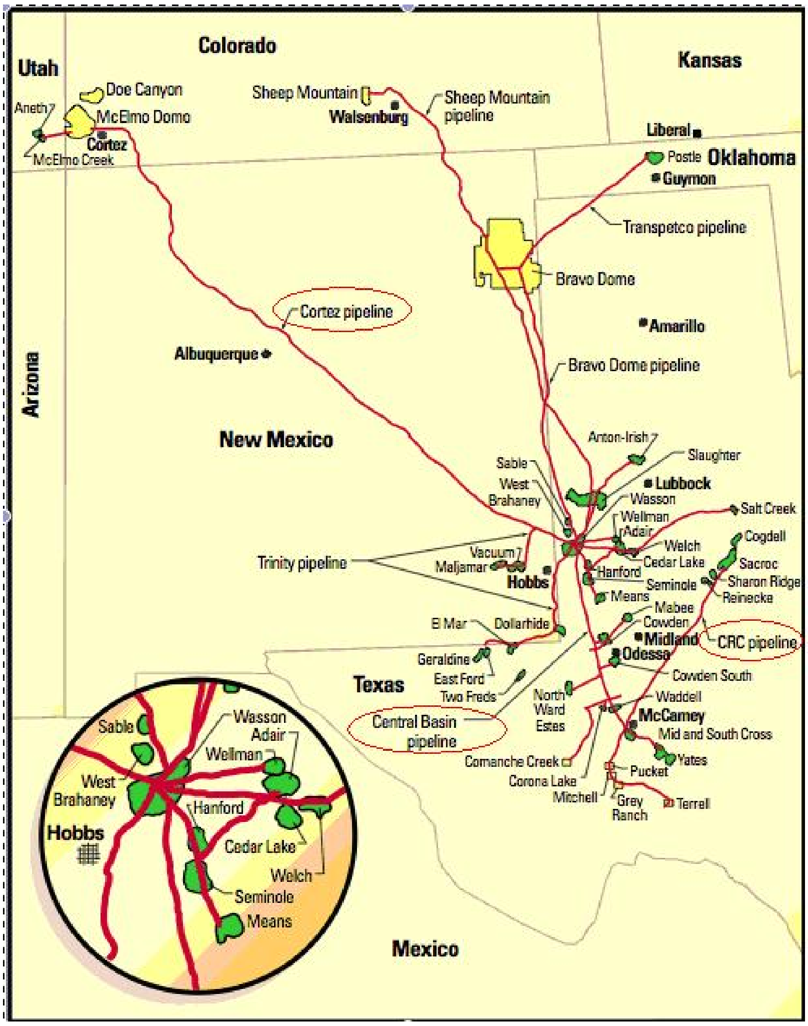
> is a major pipeline transportation and energy storage company in North America with more than 37,000 miles of pipelines and 170 terminals. It transports, stores and handles energy products like natural gas, refined petroleum products, crude oil, ethanol, coal and carbon dioxide (CO_2). Kinder Morgan delivers approximately 1.3 billion cubic feet per day of CO_2 through about 1,300 miles of pipelines.

The map in Figure A3.1 presents KM's CO_2 pipeline network.

KM owns the two largest natural CO_2 fields in the US. The McElmo Dome, primarily owned by KM and ExxonMobil, produces up to 50 MMcfd from 61 production wells. The Bravo Dome, with more than 10 tcf of CO_2, connects to the Denver City Hub via the Cortez pipeline (1 bcfd to 4 bcfd). From this hub more than 40 smaller pipelines distribute CO_2 to various oil fields (EOR operations). The smaller pipelines are often partly or entirely owned by KM, which also acts as the pipeline operator. In addition, KM offers some customers risk-sharing instruments, such as financing, royalty interests and other mutually agreed arrangements (Kinder Morgan, 2010).

According to the a report for US DOE (Advanced Resources International, 2006), an additional 210 billion barrels could be produced domestically with EOR. Due to increasing demand, both the McElmo Dome and its pipelines have recently expanded. Still, the main barrier to stronger growth is the limited availability of low-cost CO_2. In contrast to the European market, where storage capacity is scarce and there are limited incentives for network construction, the availability of CO_2 for storage (i.e. employed as a valuable commodity) is the scarce resource for which companies strive.

Figure A3.1 CO_2 pipelines for oil and gas reservoir sequestration used by Kinder Morgan



Source: Moritis (2001).

Ownership of the CO_2 transport network puts KM in a strong position when negotiating CO_2 prices. Yet CO_2 can only be used in EOR operations at low costs. Furthermore, enhanced fossil fuel production can be undertaken to some extent with water, and substitution with nitrogen is likewise possible depending on the resources available and the extent of depletion of the field. Still, as a pipeline operator KM is strongly dependent on a steady flow of CO_2 because the cost of the network represents the largest share of the CO_2 delivery price. Therefore, its ability to engage in market power is limited, even though it faces some risk of opportunistic behaviour by its customers. KM uses the vertical integration of the backbone and distribution networks (and to some extent injection services) and long-term CO_2 delivery contracts to hedge its post-contractual risks of opportunistic bargaining as well as price and quantity risks.

Contractual data are only publicly available for the Val Verde and the North-East Jackson Dome pipelines. The 20-year contracts demand a fixed payment of US$150,000 monthly for CO_2 from the Val Verde pipeline and US$100,000 from the Jackson Dome pipeline, respectively. Each contract contains a tariff based on throughput and two 5-year renewal options. Genesis purchased Denbury's Free State Pipeline for US$75 mn and entered into a 20-year transportation services agreement to deliver CO_2 to Denbury's EOR operations. Denbury has exclusive use of the pipeline and must use it to supply CO_2 to its tertiary operations in the region. Genesis also entered into a 20-year financing lease transaction valued at US$175 mn, wherein Genesis acquired certain security interests in Denbury's North-East Jackson Dome Pipeline System. Denbury has exclusive use of the pipeline and is responsible for all operations and maintenance (Reuters, 2010b).

Our analysis reveals a high level of vertical integration, often true of sectors requiring capital-intensive investment with a high risk of sunk costs in the future. Unlike natural gas supply, however, an interruption of the CO_2 stream is less harmful to the business of an oil producer or CO_2 supplier. After CO_2 injection begins, it takes one to two years until oil production increases. Similarly, oil production does not cease when the CO_2 supply is interrupted for technical or other reasons. Texas has a well-developed network, mainly owned by KM. This company offers to manage the entire upstream part of the CO_2 value-added chain, including injection into the oil field. For the supplier of CO_2, lower demand means reducing production if it relies on a natural source or is released into the atmosphere. The costs of production and injection into oil fields are rather minor compared to the pipeline. Commonly used backbone pipelines, such as the Central Basin Pipeline, can help reduce overall system costs and spread the risk amongst a larger number of players.

Network regulation in the US

Regulation of the CO_2 network in the US is still in its infancy, with the existing network developing mainly on a regional scale initiated by the economic benefits of CO_2 in EOR. Most transport occurs at the intrastate level where provision, access and regulation traditionally have not been major issues. Nevertheless, its future could replicate the history of fossil fuel transport via pipelines, where regulation emerged as a consequence of public anger concerning mergers, price and monopolistic behaviour in the late 19th century. At that time, John D. Rockefeller's Standard Oil Company controlled 90% of oil refining and 80% of oil transportation markets in the US (Reed, 2004). The Hepburn Act of 1906 granted federal regulatory responsibility over interstate oil pipelines to the Interstate Commerce Commission (ICC). The ICC ruled that most of the interstate pipelines were common carriers, established rates of return based on the principle of 'just and reasonable' and required the allocation of shipments on a non-discriminatory basis (Figueiredo et al., 2007). In 1977 responsibility for oil pipelines was transferred to the US Federal Energy Regulatory Commission (FERC), which implemented a pricing index for upper-level oil pipeline transportation charges. FERC also oversees transportation rates, capacity allocation and network expansion, including natural gas storage facilities.

In 1978, the Cortez Pipeline Company revealed a regulatory vacuum when the company argued (successfully) that FERC was only responsible for regulating the transport of natural gas as hydrocarbons and not naturally occurring gases. In 1980, when it appeared before the ICC, the latter stated that it was not in charge of regulating any types of gases. The Surface

Transportation Board, successor to the ICC, also disclaimed responsibility over interstate CO_2 transport. Contributing to the chaos, the abuse of market power by vertically integrated firms or pipeline operators is under the jurisdiction of the Federal Trade Commission and the antitrust division of the US Department of Justice.

Should CCTS ever be widely applied, the sector will be composed of plants and storage owned or controlled by many players and a well-developed pipeline network at intra- and interstate levels. Even though the history of natural gas and oil pipeline transportation demonstrates that a well-defined regulatory authority provides assurances to public and private investment alike, the US regulatory framework for CO_2 transport and storage remains fragmented across the permit processes at many stages of the value chain.

Appendix 4. CCTS database: Capture projects

Table A4.1 Announced and planned CCTS projects

Project name	Location	Leader	Feedstock	Size (MW)	Capture process	CO_2 fate	Start-up (original) current	Current project status	Cost estimation	Public funding
Abu Dhabi Project	Abu Dhabi	Masdar	Various industrial	Various	Various	EOR	(2013) 2014	Tender	$2 bn	–
Callide-A Oxy Fuel	Australia	CS Energy	Coal	30	Oxy	Seq	2011	Construction	$131 mn	$33 mn
Wandoan	Australia	–	Coal	334	Pre	Seq	2015	Pre-feasibility	–	–
ZeroGen	Australia	ZeroGen (Queensland State)	Coal	400	Pre	Seq	(2015) 2017	Planning	AUD$4.3 bn	$300 mn
Maritsa	Bulgaria	BEH	Lignite	600	Pre	EOR/EGR	Undecided	Announced	€850 mn	–
Fort Nelson	Canada	PCOR	Gas	Gas process	Pre	Saline aquifer	2012	Feasibility Study	–	$3.4 (Feasibility study)
Boundary Dam	Canada	SaskPower	Coal	100	Oxy	EOR	2015	Announced	$1.4 bn	$250 mn
Bow City	Canada	BCPL	Coal	500 + 500	Post	EOR	(2014) 2016	Announced	–	–
Project Pioneer	Canada	TransAlta	Coal	450	Post	EOR/Seq	2015	Planning	–	$431 mn (5 years) + 343 + 436
Shell Quest Project	Canada	Shell	Gas	Various	Pre	Seq/EOR	2015	Planning	–	–
Swan Mills	Canada	Swan Hills Synfuels	ISCG (unminable coal seams)	–	–	EOR	2009 (Demo) 2015 (Operation)	Demonstration	$1.5 bn	$255 mn

Table A4.1 cont'd

PCC Demo Project Gaobeidian	China, Beijing	Huaneng	Coal	3,000 tCO_2pa	Post	Sell for industrial utilisation (EOR, food processing)	2008	Operating	AUD$4 mn	–
NZEC	China, exact location TBD	UK, EU, China, Norway	Coal	750–1,000	Undecided	Seq or EOR	2014	Planning	$59-795 mn	EU: $103 mn, UK: $7 mn, Norway: $9.3 mn
Dongguan Taiyangzhou IGCC	China, Guangdong	Dong Guan Power & Chemical Industry	Coal	750 MW net; 0.1-1 $MtCO_2$pa	Pre	Saline	2020	Planning	–	–
Ordos	China, Inner Mongolia	Shenhua Group	Liquefied coal	1 $MtCO_2$pa	–	EOR or Saline	2010	Construction	$1.4 bn	–
Lianyungang IGCC	China, Jiangsu	–	Coal	1,200 MW IGCC & 1,300 USC-PC plant; 0.1-1 $MtCO_2$pa	Pre	EOR	2016	Planning	–	–
Shidongkou	China, North Shanghai	Huaneng	Coal	0.1 $MtCO_2$pa	Post	Sell for industrial utilisation (EOR, food processing)	2010	Construction	$22 mn	–
Chemical Plant, Yulin	China, Shanxi	Dow and Shenua	Liquefied coal	5-10 $MtCO_2$pa	Pre	Undecided	2020	Planning	–	–
GreenGen	China, Tianjin	Huaneng	Coal	250 (pilot) 800	Pre	Seq	2010 2020	Planning	$3.3 bn	$46 mn
Hodonin CEZ	Czech Republic	CEZ	Lignite, biomass	105	Post	Depleted oil and gas field	2015	Planning	–	–

Table A4.1 cont'd

Ledvice CEZ	Czech Republic	CEZ	Lignite	660 (CR)	Post	Saline aquifer	2015	Planning	–	–
Kalundborg	Denmark	DONG Energy	Coal	600	Post	Saline aquifer	2016	Planning	–	–
Aalborg	Denmark	Vattenfall	Coal	410	Post	Saline aquifer	2013	Postponed	–	–
FINNCAP	Finland	Fortum	Coal	565	Pre	EOR, Danish North Sea	2015	Planning	–	–
Total Lacq	France	Total	Heavy oil	35	Oxy	Seq in gas fields	2010	Operating	€60 mn	–
Schwarze Pumpe	Germany	Vattenfall	Coal	30 (pilot) 300 (demo) 1,000	Oxy	Seq/EOR	2008	Operating	€70 mn (pilot)	–
Jänschwalde	Germany	Vattenfall	Coal	375	Oxy & Post	Deep saline aquifer	2015	Planning	$1.58 bn	€180 mn, EEPR
Wilhelmshaven	Germany	E.ON	Coal	5.5 (pilot)	Post	Deep saline aquifer	2010	Planning completed	€10 mn (pilot)	–
Großkrotzenburg /Staudinger	Germany	E.ON/Siemens	Coal	510	Post	–	2010	Construction	–	–
Niederhausem	Germany	RWE	Coal	Pilot project	Post	–	2009	Operating	€9 mn	–
Brindisi	Italy	Enel and Eni	Coal	242	Post	Seq	2010	Construction	–	–
Porto-Tolle	Italy	Enel	Coal	3 * 660	Post	Saline formation in sea	2015	Planning	€800 mn	€100 mn, EEPR
Saline Joniche	Italy	SEI	Coal	1,320 (CR)	Post	Undecided	Undecided	Announced	–	–
Nuon Magnum, Eemshaven	Netherlands	Nuon	Coal	1,200 (CR)	Pre	Seq	(2013) 2015	Construction	–	Reserve list, EEPR
Maasvlakte, Rotterdamm	Netherlands	Rotterdam Climate Initiative E.ON Benelux, Electrabel	Coal	1,040 (CR)	Post	EGR	2015	Construction	€1.2 bn	€180 mn, EEPR

Table A4.1 cont'd

Eemshaven RWE	Netherlands	RWE	Coal	40	Post	Depleted oil and gas field	2016	Planning	–	–
Rotterdam CGEN	Netherlands	CGEN NV	Coal, biomass	450	Pre	Depleted oil and gas field	2013	Announced	–	–
Rotterdam Essent	Netherlands	Essent	Coal, biomass	1,000	Pre	Depleted oil and gas field	2016	Announced	–	–
Statoil Mongstad	Norway	Statoil	Gas	350 + 280 CHP	Post	Seq	(2011) waiting founding decision in 2014	Planning	$2.7 bn	Unclear
Tjeldbergodden	Norway	Shell/Statoil	Gas	860	Post	EOR	–	Abandoned	–	–
Naturkraft Kårstø	Norway	Naturkraft	Gas	420 (CR)	Post	Undecided	2011-2012	Planning	$927 mn	$640 mn (state)
Belchatow	Poland	PGE EBSA	Lignite	250 (Pilot) 858 (Demo)	Post	Saline aquifer	2011 (pilot) 2015 (Demo)	Planning/ Construction	–	€180 mn, EEPR
Siekierki	Poland	Vattenfall	Coal	480 (CR)	Post	Undecided	2016	Planning	–	–
Kędzierzyn	Poland	PKE	Coal	700	Pre	Saline aquifer	(2014) 2015	Planning	€1,300 mn	–
Compostilla	Spain	ENDESA	Coal	30 (pilot) 322 (demo)	Oxy	Deep saline aquifer	2010 (pilot), 2015	Planning	€500 mn	€180 mn, EEPR, (280-450 mn in EU allowances)
Puertollano	Spain	Bellona	Coal, Petcoke	14	Pre	Saline aquifer	2009	Construction	€18.5 mn	–
E.ON Karlshamn	Sweden	E.ON	Oil	5	Post	Undecided	2014	Operating	€11 mn	–
Scottish and Southern Energy Ferrybridge/ Yorkshire	UK	SSE	Coal	500 (CR)	Post	Seq	2012	Planning	£250 mn + 100 mn CCS	–

Table A4.1 cont'd

Teesside	UK	CE	Coal	800	Pre	Seq	2015	Announced	$1,500 mn	–
Powerfuel Hatfield	UK	Powerfuel	Coal	900	Pre	EOR	2014	Construction	$1.6 bn	€180 mn EEPR + 180 mn (UK)
Longannet	UK	Scottish Power	Coal	300	Post	EOR/Seq	2014	Testing 1 MW prototype	£1 bn	Reserve list, EEPR
Drym	UK	Progressive Energy	Coal	450	Pre	Undecided	Undecided	Announced	–	–
Immingham	UK	Conoco Phillips	Gas	450	Post	Seq	2010?	Construction	–	–
Aberthaw	UK	RWE	–	3 (Pilot), 25 (Phase 2)	Post	–	2010	Construction	£8.4 mn	–
Onllwyn	UK	Valleys Energy	Coal	450	Pre	–	2014	Planning	–	–
Renfrew	UK	Doosan Babcook, DECC, Scottish/ Southern Energy	–	40	Oxy	–	2009	Operating	–	–
Pleasant Prairie	US	AEP	Coal	5	Post	Seq	2008	Operating	–	–
AEP Alstom Mountaineer	US	AEP	Coal	30 235	Post	Seq	2009	Operating	$8.6 mn $668 mn	$7.2 mn $334 mn
Williston	US	PCOR	Coal	450	Post	EOR	2014	Announced	–	–
Kimberlina	US	CES	Coal	50	Oxy	Seq	2010	Announced	–	–
AEP Alstom Northeastern	US	AEP	Coal	200	Post	EOR	2011	Announced	–	–
Plant Barry	US	MHI	Coal	25 (Pilot) 160 (Demo)	Post	Seq	2011	Planning	–	$295 mn
Antelope Valley	US	Basin Electric	Coal	120	Post	EOR	2012	Planning	–	$100 mn

Table A4.1 cont'd

Appalachian Power	US	AEP	Coal	629	Pre	Undecided	2012	Announced	US$700 mn	–
WA Parish	US	NRG Energy	Coal	60	Post	EOR	2013	Planning	–	–
Wallula Energy Resource Centre	US	Wallula Energy	Coal	700	Pre	Seq	2014	Announced	US$2.2 bn	–
Hydrogen Energy California	US	HEI	Petcoke	250	Pre	EOR	(2014) 2015	Planning	–	$308 mn
Trailblazer	US	Tenaska	Coal	765	Post	EOR	2014	Planning	–	–
ZENG Worsham-Steed	US	CO_2-Global	Gas	70	Oxy	EOR	Undecided	Announced	–	–

Source: Own compilation from various publicly available data.

Table A4.2 Postponed or cancelled CCTS projects

Project name	**Location**	**Leader**	**Feedstock**	**Size MW**	**Capture process**	**CO_2 fate**	**Operation**	**Current project status**	**Cost estimation**	**Public funding**
FutureGen	US	FutureGen Alliance	Coal	275	Pre	Seq	Restudying	–	–	–
BP Carson (DF2)	US	Hydrogen Energy	Petcoke	500	Pre	EOR	Re-Structuring	–	$2 bn	–
E.ON Killingholme	UK	E.ON	Coal	450	Pre	Seq	Dormant	Cancelled?	–	–
Monash Energy	Australia	Monash	Coal	60 k bpd	Pre	Seq	Dormant	Cancelled?	–	–
UAE	UAE	Masdar	Gas	420	Pre	EOR	Delayed	Cancelled?	–	–

Table A4.2 cont'd

Greifswald	Germany	Dong Energy	–	–	–	–	–	Cancelled?	$2-3 bn	–
RWE Goldenbergwerk Huerth	Germany	RWE	Coal	320	Pre	Seq	2015	Postponed?	€2 bn	Reserve list, EEPR
Kingsnorth	UK	E.ON	Coal	800 (CR)	Post	Depleted Gas Field	(2014) 2016	Postponed?	£1 bn	Reserve list, EEPR
Sargas Husnes	Norway	Sargas	Coal	400	Post	EOR	2010-2015	Postponed?	$700 mn	–
ZENG Risavika	Norway	Zeng AS	Gas	50-70	Oxy	Undecided	Undecided	Postponed?	–	–

Source: Own compilation from various publicly available data.

Appendix 5. International CO_2 transport and storage projects

Table A5.1 International CO_2 (capture), transport and storage projects: CO_2 sources (part 1)

				CO_2 Feedstock						
No.	**Project name**	**Start-up**	**Country**	**Location**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Reserves (Nm³)**
1	**Cortez Pipeline**	1984	US	McElmo Dome, Colorado	Geological	Kinder Morgan,	45	Kinder Morgan	–	4,028E+11
						ExxonMobil,	44			
						Chevron,	4			
						multiple private	8			
2	**McElmo Creek Pipeline**		US	McElmo Dome, Colorado	Geological	Kinder Morgan,	45	Kinder Morgan	Take-or-pay contract with Kinder Morgan (including option)	4,028E+11
						ExxonMobil,	44		Take-or-pay contract with Exxon Mobil	
						Chevron,	4			
						multiple private				
3	**Bravo Pipeline**	1984	US	Bravo Dome, New Mexico	Geological	Oxy, formerly 'Occidental Permian',	75	–	–	8,056E+10
						Kinder Morgan,	11			
						Amerada Hess,	10			
						multiple private	4			
4	**Transpetco/**	1996	US	Bravo Dome, New Mexico	Geological	Oxy,	75	–	–	8,056E+10
	Bravo Pipeline					Kinder Morgan,	11			
						Amerada Hess,	10			
						multiple private	4			

Table A5.1 cont'd

5a	**Sheep Mountain**	–	US	Sheep Mountain, Colorado	Geological	BP,	50	Oxy	–	1,343E+10
	(northern)					ExxonMobil	50			
5b	**Sheep Mountain**	–	US	Sheep Mountain, Colorado	Geological	BP, ExxonMobil	50, 50	Oxy	–	1,343E+10
	(southern)			Bravo Dome, New Mexico	Geological	Oxy,	75			8,056E+10
						KM, Amerada Hess,	11, 10			
						multiple private	4			
6	**Central Basin Pipeline**	–	US	No single source	–	–	–	–	–	–
7	**Este Pipeline**	–	US	Denver City Hub	Geological	–	–	–	–	–
8	**Slaughter P.**	–	US	Denver City Hub	Geological	–	–	–	–	–
9	**West Texas P.**	–	US	Denver City Hub	Geological	–	–	–	–	–
10	**Llano Lateral**	–	US	Cortez Pipeline (McElmo Dome)	Geological	–	–	–	–	–

Source: Own compilation from various publicly available data.

Table A5.2 International CO_2 (capture), transport and storage projects: CO_2 sources (part 2)

				CO_2 Feedstock						
No.	**Project Name**	**Start-up**	**Country**	**Location**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Reserves (Nm³)**
11	**Canyon Reef Carriers Pipeline**	1972	US	–	Industrial (?)	–	–	–	–	–
12	**Val Verde Pipeline**	1998	US	Pecos/Terrell Counties, Texas	Industrial	–	–	–	–	–
13	**North East Jackson Dome Pipeline**	1985	US	Jackson Dome, Mississippi	Geological	Denbury	100	–	–	2,148E+10
14	**Free State Pipeline**	2006	US	Jackson Dome, Mississippi	Geological	Denbury	100	–	–	2,148E+10
15a	**Delta Pipeline**	2008	US	Jackson Dome, Mississippi	Geological	Denbury	100	–	–	2,148E+10
15b	**Delta Pipeline extension**	2009	US	Jackson Dome via Tinsley Field	Geological	Denbury	100	–	–	2,148E+10
16	**Cranfield**	2008	US	Natchez, Mississippi	Geological Industrial	– Southern Company	–	Public Research Project	–	–
17	**Weyburn-Souris Valley Pipeline**	2000	US/CAN	Great Plains Synfuels Plant, North Dakota	Industrial	Dakota Gasification Company, subsidiary of Basin Power Cooperative	100	Dakota Gasification Company, subsidiary of Basin Electric Power Cooperative	–	–
18	**Antelope Valley**	2012	US/CAN	Beulah, North Dakota	Power plant	Basin Electric Power Cooperative	100	Basin Electric Power Cooperative	–	–
19	**Green Pipeline**	2010	US	Donaldsonville, Louisiana	–	–	–	–	–	–

Table A5.2 cont'd

20	**Snøhvit**	2007	Norway	Barents Sea	Industrial	Petoro	–	StatoilHydro	–	0.7 $MtCO_2$pa
21	**In Salah**	2004	Algeria	Central Algeria	Industrial	BP Sontrach Statoil	32 35 32	BP	–	1.2 $MtCO_2$pa
22	**Lacq**	2010	France	Lacq	Industrial	Total Air Liquide IFP BRGM Alstom	–	Total	–	0.075 $MtCO_2$pa
23	**Sleipner**	1996	Norway	North Sea, near Stavanger	Industrial	Statoil	–	Statoil	–	1 $MtCO_2$pa
24	**Gorgon**	2014	Australia	Barrow Island	Industrial	Chevron ExxonMobil Shell	50 25 25	–	–	3.3 $MtCO_2$pa

Source: Own compilation from various publicly available data.

Table A5.3 International CO_2 (capture), transport and storage projects: CO_2 sources (part 3)

				CO_2 Feedstock						
No.	**Project name**	**Start-up**	**Country**	**Location**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Reserves**
24	**ZeroGen**	2015	Australia	Pre-feasibility study completion June 2010, Shell expects 200 km of pipeline	Power plant	–	–	–	–	–
25	**Alberta Carbon Trunk Line**	2012	Canada	Agrium Redwater Complex	Industrial	Agrium North West Upgrading	–	Agrium	'Long-term CO_2 supply agreement'	–
				North West Upgrader	Industrial	–	–	North West Upgrading	'Long-term CO_2 supply agreement'	

Table A5.3 cont'd

26	**Jänschwalde**	2013	Germany	Jänschwalde	Power plant	Vattenfall	100	Vattenfall	–	–
27	**Aalborg**	Postponed	Denmark	Nordjyllandsverket, Aalborg	Power plant	Vattenfall	100	Vattenfall	–	–
28	**Schwarze Pumpe**	2008	Germany	–	Power plant	Vattenfall	100	Vattenfall	–	–
29	**Callide Oxyful Project**	2011	Australia	Callida A Power Station, Queensland	Power plant	–	–	–	–	–
30	**Plant Barry**	2011	US	Plant Barry, Mobile, Alabama	Power plant	Alabama Power, subsidiary of Southern Company	100	Alabama Power	–	–
31	**Coastal Energy Teesside**	2012	UK	Teesside, England	Power plant	Coastal Energy, a company owned by Centrica Energy and Progressive Energy	100	Coastal Energy	–	–
32	**Tenaska Trailblazer Energy Centre**	2015	US	Sweetwater, Texas	Power plant	Tenaska Energy	100	Tenaska Energy	–	–
33	**Hydrogen Energy California**	2014	US	Kern County, California	Power plant	Hydrogen Energy International (HEI), joint effort by BP and Rio Tinto	100	–	–	–
34	**Goldenbergwerk**	2015	Germany	Hürth, Germany	Power plant	RWE	100	RWE	–	–
35	**Boundary Dam**	2015	Canada	Estevan, Saskatchewan	Power plant	SaskPower	100	Saskpower	–	–
36	**FINNCAP**	2015	Finland	Meri Pori, Finland	Power plant	Fortum	55	Fortum	–	–
						Teollisuuden Voima	45			

Table A5.3 cont'd

37	**Hatfield**	2014	UK	Hatfield Colliery, England	Power plant	Powerfuel	100	Powerfuel	–	–
38	**Recôncavo**	1987	Brazil	–	Industrial	–	–	–	–	–
39	**Bati Raman**	1983	Turkey	Dodan field	Geological	Turkish Petroleum	–	–	–	–

Source: Own compilation from various publicly available data.

Table A5.4 International CO_2 (capture), transport and storage projects: CO_2 pipelines (part 1)

				CO_2 Transport								
No.	**Project name**	**Start-up**	**Country**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Distance (km)**	**Size (m)**	**Pressure (bar)**	**Capacity (Nm³/d)**
1	**Cortez Pipeline**	1984	US	Pipeline	Cortez Pipeline	100	Cortez Pipeline	–	808	0.762	130	2,954E+07
2	**McElmo Creek Pipeline**	–	US	Pipeline	Resolute Energy Partners	100	Resolute Energy Partners	–	64	00203	130	1,611E+06
3	**Bravo Pipeline**	1984	US	Pipeline	Oxy, Kinder Morgan, XTO-Energy	–	BP	–	351	0.508	124–131	1,026E+07

Table A5.4 cont'd

4	**Transpetco /Bravo Pipeline**	1996	US	Pipeline	Whiting Petroleum Corp.	60	Transpetco	–	193	0.324	–	4,699E+06
5a	**Sheep Mountain (northern)**	–	US	Pipeline	Oxy ExxonMobil	–	Oxy	–	296	0.508	–	8,861E+06
5b	**Sheep Mountain (southern)**	–	US	Pipeline	Oxy ExxonMobil	–	Oxy	–	360	0.610	141	1,289E+07
6	**Central Basin Pipeline**	–	US	Pipeline	Kinder Morgan	–	–	–	225	0.660–0.406 0.356–0.305	–	1,611E+07 6,713E+06
7	**Este Pipeline**	–	US	Pipeline	Oxy ConocoPhillips	–	Oxy	–	64	0.305	–	4,296E+06
8	**Slaughter P.**	–	US	Pipeline	Trinity Pipeline	100	Trinity Pipeline	Likely contracted to Oxy	204	0.305–0.203	–	2,685E+06
9	**West Texas P.**	–	US	Pipeline	Trinity Pipeline	100	Trinity Pipeline	–	85	0.305–0.203	–	2,685E+06
10	**Llano Lateral**	–	US	Pipeline	Kinder Morgan	100	–	–	225	0.406	–	7,250E+06

Source: Own compilation from various publicly available data.

Table A5.5 International CO_2 (capture), transport and storage projects: CO_2 pipelines (part 2)

				CO_2 Transport								
No.	**Project name**	**Start-up**	**Country**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Distance (km)**	**Size (m)**	**Pressure (bar)**	**Capacity (Nm³/d)**
11	**Canyon Reef Carriers Pipeline**	1972	US	Pipeline	SandRidge CO_2, ARCO Permian, subsidiary of BP	78 22	–	–	132	0.254	–	–
12	**Val Verde Pipeline**	1998	US	Pipeline	Genesis Energy	100	Denbury	1)	295	0.508	–	1,383E+07
13	**North East Jackson Dome Pipeline**	1985	US	Pipeline	Genesis Energy	100	Genesis Energy	2)	138	0.508	–	–
14	**Free State Pipeline**	2006	US	Pipeline	–	–	–	–	50	–	–	–
15a	**Delta Pipeline**	2008	US	Pipeline	–	–	–	–	109	–	–	–
15b	**Delta Pipeline extension**	2009	US	Pipeline	–	–	–	–	–	–	–	–
16	**Cranfield**	2008	US	Pipeline	Souris Valley Pipeline Ltd, subsidiary of Dakota Gasification Company	100	Souris Valley Pipeline Ltd, subsidiary of Dakota Gasification Company	–	330	0.356–3.05	186	4,028E+06
17	**Weyburn-Souris Valley Pipeline**	2000	US/CAN	–	–	–	–	–	330	–	–	–
18	**Antelope Valley**	2012	US/CAN	Pipeline	Souris Valley Pipeline Ltd, subsidiary of Dakota Gasification Company	100	Souris Valley Pipeline Ltd, subsidiary of Dakota Gasification Company	–	330	0.356–3.05	186	4,028E+06

Table A5.5 cont'd

19	**Green Pipeline**	2010	–	–	–	US	–	–	–	–	–	–
20	**Snøhvit**	2007	Norway	Pipeline	Denbury	100	–	–	515	0.610	–	2,148E+07
21	**In Salah**	2003	Algeria	Pipeline	BP Sontrach Statoil	32 35 32	BP	–	143	0.203	185	9,695E+05
22	**Lacq**	2010	France	Pipeline	Total Air Liquide IFP BRGM Alstom	–	Total	–	30	–	–	–
23	**Sleipner**	1996	Norway	Pipeline	Total	100	Total	–	30	–	30	–

1) "[T]wenty-year financing lease transaction with Denbury valued at $175 million. …Denbury has exclusive use of the NEJD pipeline system and will be responsible for all operations and maintenance on the system" (see http://www.reuters.com/article/pressRelease/idUS109548+02-Jun-2008+BW20080602).

2) "Genesis…entered into a twenty-year transportation services agreement to deliver CO_2 on that pipeline for Denbury's use in its tertiary recovery operations. …Under the terms of the transportation services agreement, Denbury has exclusive use of the pipeline and is required to use the pipeline to supply CO_2 to its tertiary operations in that region. The services agreement provides for a $100,000 per month minimum payment plus a tariff based on throughput. Denbury has two renewal options for five years each on similar terms."

Source: Own compilation from various publicly available data.

Table A5.6 International CO_2 (capture), transport and storage projects: CO_2 pipelines (part 3)

				CO_2 Transport								
No.	**Project name**	**Start-up**	**Country**	**Type**	**Owners**	**(%)**	**Operator**	**Contracting structure**	**Distance (km)**	**Size (m)**	**Pressure (bar)**	**Capacity (Nm³/d)**
24	**ZeroGen**	2015	Australia	–	–	–	–	–	200	–	–	–
25	**Alberta Carbon Trunk Line**	2012	Canada	Pipeline	Enhance Energy	100	–	–	240	0.406–0.324	–	8,056E+06

Table A5.6 cont'd

26	**Jänschwalde**	2013	Germany	Pipeline	–	–	–	–	150	–	–	–
27	**Aalborg**	Postponed	Denmark	Pipeline	Vattenfall	–	Vattenfall	–	30	–	–	–
28	**Schwarze Pumpe**	2008	Germany	–	–	–	–	–	–	–	–	–
29	**Callide Oxyful Project**	2011	Australia	Truck	–	–	–	–	300	–	–	–
30	**Plant Barry**	2011	US	Pipeline	SECARB	–	SECARB	–	16	–	–	2,078E+05
31	**Coastal Energy Teesside**	2012	UK	Pipeline	COOTS, owned by Centrica	100	COOTS	–	–	–	–	–
32	**Tenaska Trailblazer Energy Centre**	2015	US	Pipeline	Plant site not determined; will probably utilise Canyon Reef Carriers Pipeline	–	–	–	~ 60	–	–	–
33	**Hydrogen Energy California**	2014	US	Pipeline	–	–	–	–	–	–	–	–
34	**Goldenbergwerk**	2015	Germany	Pipeline	RWE DEA	–	–	–	–	–	–	–
35	**Boundary Dam**	2015	Canada	Pipeline	–	–	–	–	–	–	–	–
36	**FINNCAP**	2015	Finland	Ship	Fortum Teollisuuden Voima	55 45	Fortum	–	–	–	–	–
37	**Hatfield**	2014	UK	Pipeline	Kuzbassrazrezugol	–	–	–	–	–	–	–
38	**Recôncavo**	1987	Brazil	Pipeline	Petrobras	–	–	–	183	0.254–0.102	–	8,321E+03
39	**Bati Raman**	1983	Turkey	Pipeline	Turkish Petroleum	–	–	–	90	–	–	1,524E+06

Source: Own compilation from various publicly available data.

Table A5.7 International CO_2 (capture), transport and storage projects: CO_2 sinks (part 1)

				CO_2 Sink							
No.	**Project name**	**Start-up**	**Country**	**Type**	**Location**	**Owners**	**(%)**	**Operator**	**Start of operation**	**Contracting structure**	**Total capacity (Nm³)**
1	**Cortez Pipeline**	1984	US	EOR	Denver City Hub, Texas	–	–	–	–	–	–
2	**McElmo Creek Pipeline**	–	US	EOR	McElmo Creek Unit, Utah	Resolute Energy Partners, multiple private	75	Resolute	–	–	–
3	**Bravo Pipeline**	1984	US	EOR	Denver City Hub, Texas	–	–	–	–	–	–
4	**Transpetco/ Bravo Pipeline**	1996	US	EOR	Postle Field, Oklahoma	Whiting Petroleum Corp.	100	–	–	–	–
5a	**Sheep Mountain (northern)**	–	US	EOR	Denver City Hub, Texas; via Bravo Dome	–	–	–	–	–	–
5b	**Sheep Mountain (southern)**	–	US	EOR	Denver City Hub, Texas	–	–	–	–	–	–
6	**Central Basin Pipeline**	–	US	EOR	Salt Creek Terminus	Oxy	–	–	–	–	–
7	**Este Pipeline**	–	US	EOR	Salt Creek Terminus	Oxy	–	–	–	–	–
8	**Slaughter P.**	–	US	EOR	Slaughter Field	–	–	–	–	–	–
9	**West Texas P.**	–	US	EOR	Hobbs Field, Keystone Field, Two Freds Field	–	–	–	–	–	–
10	**Llano Lateral**	–	US	EOR	Vauum Unit, Maljamar, C. Vac	–	–	–	–	–	–

Source: Own compilation from various publicly available data.

Table A5.8 International CO_2 (capture), transport and storage projects: CO_2 sinks (part 2)

				CO_2 Sink							
No.	**Project name**	**Start-up**	**Country**	**Type**	**Location**	**Owners**	**(%)**	**Operator**	**Start of operation**	**Contracting structure**	**Total capacity (Nm^3) annual injection rate ($MtCO_2pa$)**
11	**Canyon Reef Carriers Pipeline**	1972	US	EOR	SARCO Field	Kinder Morgan	–	–	–	–	–
12	**Val Verde Pipeline**	1998	US	EOR	SARCO Field	Kinder Morgan	–	–	–	–	–
13	**North East Jackson Dome Pipeline**	1985	US	EOR	Little Creek Field	Denbury	100	Denbury	1999	–	–
14	**Free State Pipeline**	2006	US	EOR	Eucutta, Soso, Martinville and Heidelberg Field, Mississippi	Denbury	100	Denbury	2006	–	–
15a	**Delta Pipeline**	2008	US	EOR	Tinsley Field	Denbury	100	Denbury	–	–	–
15b	**Delta Pipeline extension**	2009	US	EOR	Delhi Field	Denbury	100	Denbury	2009	–	–
16	**Cranfield**	2008	US	EOR Saline	Cranfield Oil Field, Natchez, Mississippi	Denbury Resources ?	100	–	–	–	–

Table A5.8 cont'd

17	**Weyburn-Souris Valley Pipeline**	2000	US/CAN	EOR	Weyburn field, Saskatchewan, Canada	EnCana	100	EnCana	–	–	3,564E+07
18	**Antelope Valley**	2012	US/CAN	–	–	–	–	–	–	–	–
19	**Green Pipeline**	2010	–	–	Hastings Field, Texas	Denbury	–	–	–	–	–
20	**Snøhvit**	2007	Norway	EOR	Barents Sea	Petoro	–	Statoil Hydro	2008	–	0.7 $MtCO_2$pa
21	**In Salah**	2003	Algeria	EOR	Central Algeria	BP Sontrach Statoil	32 35 32	BP	2003	–	1.2 $MtCO_2$pa
22	**Lacq**	2010	France	Depleted gas field	Rousse field	Total Air Liquide IFP BRGM Alstom	–	Total	2010	–	0.075 $MtCO_2$pa
23	**Sleipner**	1996	Norway	Saline aquifer	North Sea, near Stavanger	Statoil	–	Statoil	1996	–	1 $MtCO_2$pa

Source: Own compilation from various publicly available data.

Table A5.9 International CO_2 (capture), transport and storage projects: CO_2 sinks (part 3)

				CO_2 Sink							
No.	**Project name**	**Start-up**	**Country**	**Type**	**Location**	**Owners**	**(%)**	**Operator**	**Start of operation**	**Contracting structure**	**Total capacity (Nm³)**
24	**ZeroGen**	2015	Australia	–	–	–	–	–	–	–	2 $MtCO_2$pa
25	**Alberta Carbon Trunk Line**	2012	Canada	EOR	Clive, Alberta, Canada	Enhance Energy	–	Enhance Energy	–	–	–
26	**Jänschwalde**	2013	Germany	–	–	–	–	–	–	–	–
27	**Aalborg**	Undecided	Denmark	EOR	Vedsted underground structure	Vattenfall	–	Vattenfall	Postponed	–	–
28	**Schwarze Pumpe**	2008	Germany	–	–	–	–	–	–	–	–
29	**Callide Oxyful Project**	2011	Australia	Depleted gas field	Dension Trough	Santos	50	–	1989	–	5-60 $MtCO_2$pa
30	**Plant Barry**	2011	US	EOR	Citronelle Oil Field	–	–	SECARB	–	–	–
31	**Coastal Energy Teesside**	2012	UK	EOR	–	–	–	–	–	–	–
32	**Tenaska Trailblazer Energy Centre**	2015	US	–	–	–	–	–	–	–	–
33	**Hydrogen Energy California**	2014	US	EOR	Elk Hills Oil Field	Oxy	–	–	–	–	–

Table A5.9 cont'd

34	**Goldenbergwerk**	2015	Germany	Saline reservoir	Schleswig-Holstein (?)	–	–	–	–	–	–
35	**Boundary Dam**	2015	Canada	EOR	–	–	–	–	–	–	–
36	**FINNCAP**	2015	Finland	EOR	Danish North Sea	–	–	–	–	–	–
37	**Hatfield**	2014	UK	EOR	North Sea oil fields	–	–	–	–	–	–
38	**Recôncavo**	1987	Brazil	EOR	Recôncavo Basin	–	–	–	–	–	–
39	**Bati Raman**	1983	Turkey	EOR	Bati Raman field	Turkish Petroleum	–	–	–	–	–
40	**Gorgon**	2014	Australia	–	Barrow Island	Chevron ExxonMobil Shell	50 25 25	–	–	–	3.3 $MtCO_2pa$
41	**Otway**	2008	Austria	Depleted gas reservoir (1,000 m)	–	CO_2CRC		–	–	–	0.1 $MtCO_2pa$

Source: Own compilation from various publicly available data.

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CENTRE FOR EUROPEAN POLICY STUDIES

Place du Congrès 1 • B-1000 Brussels
Tel: 32(0)2.229.39.11 • Fax: 32(0)2.219.41.51