



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.

CEPS Working Documents are intended to give an indication of work being conducted within CEPS research programmes and to stimulate reactions from other experts in the field. Unless otherwise indicated, the views expressed are attributable only to the authors in a personal capacity and not to any institution with which they are associated.

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

Available for free downloading from the CEPS website (<http://www.ceps.eu>)

© Centre for European Policy Studies, 2010

Contents

| | |
|---|----|
| Introduction | 1 |
| 1. Unresolved issues along the value-added chain..... | 2 |
| 1.1 Upstream: CO ₂ capture..... | 2 |
| 1.1.1 Post-combustion capture | 3 |
| 1.1.2 Pre-combustion capture | 4 |
| 1.1.3 Oxy-fuel technology | 6 |
| 1.1.4 Economics of CO ₂ capture are highly uncertain..... | 7 |
| 1.1.4.1 <i>Estimates of investment costs</i> | 7 |
| 1.1.4.2 <i>Investment under CO₂ price and technological uncertainty</i> | 10 |
| 1.2 Midstream: CO ₂ transport via pipelines..... | 11 |
| 1.2.1 Economic aspects of pipeline CO ₂ transport | 12 |
| 1.2.2 Point-to-point connections vs. a meshed network..... | 15 |
| 1.3 Downstream: CO ₂ storage | 15 |
| 1.3.1 Enhanced oil recovery: The predominant application | 15 |
| 1.3.2 Storage potential | 16 |
| 1.3.3 Leakage and monitoring | 17 |
| 2. International experiences: Great ambitions, but meagre results | 18 |
| 2.1 Great ambitions: The IEA (2009) Blue Map scenario | 18 |
| 2.2 Meagre overall results..... | 19 |
| 2.3 The US CO ₂ pipeline network | 19 |
| 2.4 Other international experiences and lessons for Europe | 21 |
| 3. Modelling future CO ₂ transport infrastructure..... | 22 |
| 3.1 Model description | 22 |
| 3.2 Data..... | 23 |
| 3.3 CCTSMOD scenarios | 24 |
| 3.4 Scenario comparisons and interpretation | 25 |
| 4. Incentivising CCTS at the European level..... | 26 |
| 4.1 Market barriers..... | 26 |
| 4.2 Shortcomings of the European Emissions Trading Scheme | 27 |
| 4.2.1 Investment support at the European level..... | 27 |
| 4.2.1.1 <i>The European Energy Programme for Recovery</i> | 27 |
| 4.2.1.2 <i>Use of 300 million CO₂ certificates for CCTS and renewables</i> | 28 |
| 4.2.1.3 <i>United Kingdom (tender approach)</i> | 29 |
| 4.2.2 Additional support instruments | 29 |

| | |
|---|----|
| 5. Conclusions and policy recommendations..... | 30 |
| List of abbreviations and symbols..... | 32 |
| Bibliography..... | 33 |
| Appendix 1. 2040 cost estimations for CCTS power plants | 39 |
| Appendix 2. International CCTS projects | 41 |
| Appendix 3. Case study: Kinder Morgan..... | 43 |
| Appendix 4. CCTS database: Capture projects..... | 47 |
| Appendix 5. International CO ₂ transport and storage projects..... | 54 |

List of Figures

| | |
|--|----|
| Figure 1. Extended value chain including the post-combustion process | 3 |
| Figure 2. Extended value chain including the pre-combustion process | 5 |
| Figure 3. Extended value chain including the oxy-fuel process | 7 |
| Figure 4. Investment costs of different systems with and without CO ₂ capture | 9 |
| Figure 5. Production costs (construction, fuel, operation and maintenance) of the different systems with and without CO ₂ capture | 9 |
| Figure 6. Investment and management decisions for a post-combustion capture unit..... | 11 |
| Figure 7. Pipeline investment cost estimates | 13 |
| Figure 8. CO ₂ transport cost comparison: On-/offshore pipeline vs. shipping transport | 14 |
| Figure 9. Estimates of CO ₂ storage capacity for Germany | 16 |
| Figure 10. Estimated CO ₂ sinks and sources in Europe | 17 |
| Figure 11. Additional investment needs for CCTS over the next ten years | 18 |
| Figure 12. Regional distribution of announced CO ₂ capture projects and technologies..... | 19 |
| Figure 13. US CO ₂ transmission network | 20 |
| Figure 14. Decision tree for the CO ₂ disposal chain of the CCTSMOD..... | 23 |
| Figure 15. BAU: CCTS infrastructure in 2050 | 26 |
| Figure 16. Offshore 120: CCTS infrastructure in 2020 (left) and 2050 (right)..... | 26 |
| Figure A3.1 CO ₂ pipelines for oil and gas reservoir sequestration used by Kinder Morgan..... | 44 |

List of Tables

| | |
|---|----|
| Table 1. CO ₂ concentrations and pressures of different combustion cycles | 3 |
| Table 2. IGCC utilities operating, selected..... | 6 |
| Table 3. Investment costs of different systems with and without CO ₂ capture | 8 |
| Table 4. Estimations of future CO ₂ abatement costs by means of CCTS | 10 |
| Table 5. Typical costs of CO ₂ capture for industrial plants | 10 |
| Table 6. Major CO ₂ pipelines in the US used for EOR operations..... | 21 |

| | | |
|------------|--|----|
| Table 7. | Major CO ₂ pipelines elsewhere in the world | 22 |
| Table 8. | Overview of scenario definitions..... | 24 |
| Table 9. | Overview of scenario results | 25 |
| Table A1.1 | Cost estimates for fossil fuel plants without CO ₂ capture in 2020 | 39 |
| Table A1.2 | Cost estimates for fossil fuel plants with CO ₂ capture in 2020 | 39 |
| Table A1.3 | Cost estimates for fossil fuel plants with CO ₂ capture in 2040 | 40 |
| Table A4.1 | Announced and planned CCTS projects..... | 47 |
| Table A4.2 | Postponed or cancelled CCTS projects..... | 52 |
| Table A5.1 | International CO ₂ (capture), transport and storage projects: CO ₂ sources (part 1) | 54 |
| Table A5.2 | International CO ₂ (capture), transport and storage projects: CO ₂ sources (part 2) | 56 |
| Table A5.3 | International CO ₂ (capture), transport and storage projects: CO ₂ sources (part 3) | 57 |
| Table A5.4 | International CO ₂ (capture), transport and storage projects: CO ₂ pipelines (part 1) | 59 |
| Table A5.5 | International CO ₂ (capture), transport and storage projects: CO ₂ pipelines (part 2) | 61 |
| Table A5.6 | International CO ₂ (capture), transport and storage projects: CO ₂ pipelines (part 3) | 62 |
| Table A5.7 | International CO ₂ (capture), transport and storage projects: CO ₂ sinks (part 1) | 63 |
| Table A5.8 | International CO ₂ (capture), transport and storage projects: CO ₂ sinks (part 2) | 64 |
| Table A5.9 | International CO ₂ (capture), transport and storage projects: CO ₂ sinks (part 3) | 67 |

CARBON CAPTURE, TRANSPORT AND STORAGE IN EUROPE

A PROBLEMATIC ENERGY BRIDGE TO NOWHERE?

CEPS WORKING DOCUMENT NO. 340/NOVEMBER 2010

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 CO₂ 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 GtCO₂ 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.

* 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 CO₂ 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 CO₂ 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 CO₂ prices and optimistic assumptions about CO₂ storage capacities. By contrast, the more likely scenario is a decrease of available storage capacity or a more moderate increase in CO₂ prices; both will significantly reduce the role of CCTS as a CO₂ 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 CO₂ 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 retrofittable post-combustion capture. Still, the scaling of these technologies and their applications to large CO₂ emitters raises new questions that can only be answered in large-scale demonstration projects.

1.1 Upstream: CO₂ capture

For some time, the small-scale capture of CO₂ 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 CO₂ 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 CO₂ concentration in the flue gas.

Table 1. CO₂ 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 |

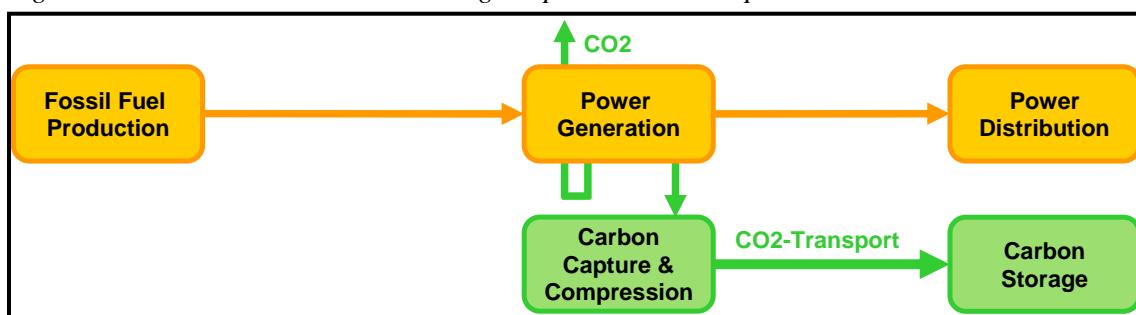
* Integrated gasification combined cycle

** Integrated reformation combined cycle

Source: Buhre et al. (2005).

1.1.1 Post-combustion capture

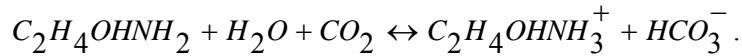
Post-combustion capture separates the CO₂ out of the flue gas after combustion (see Figure 1). This process is comparable to flue gas desulphurisation, which has long been mandatory for power plants to filter SO_x emissions. The technology was first applied in the 1980s for the capture of CO₂ from ammonia production plants. The captured CO₂ 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 CO₂ 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 CO₂ reaches concentrations in the flue gas of between 3% for natural gas and up to 15% for pulverised coal (Wuppertal Institute, 2007). The CO₂ concentration determines which post-combustion capture process can be applied. Two procedures are applicable:

I(a). Chemical absorption in combination with heat-induced CO₂ recovery is less sensitive to low CO₂ concentration and partial pressure and is applicable to natural gas plants. The CO₂ in the flue gas is chemically bonded by a monoethanolamin (MEA) or ammonia solution. The fundamental reaction for the reversible MEA process is



In a subsequent step, the MEA solution is heated to 100-120°C in a stripper and releases the CO₂, 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 CO₂ and the resulting high level of energy consumption for releasing CO₂, 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 CO₂, i.e. 0.9 MWh_{th}/tCO₂ 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 tCO₂/d. Coping with the emissions of a 1 GW lignite power plant requires up-scaling to 13 ktCO₂/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/tCO₂, for the desorber (Dardea et al., 2009). Compared with MEA, the solvent does not degrade and has a high CO₂ 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 CO₂ in the flue gas (>10%). Calculations by Kothandaraman et al. (2009) show that for a CO₂ content of 12% in the flue gas, the minimum reboiler load without energy recuperation is 0.88 MWh/tCO₂. 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/tCO₂ for the reboiler, which, when including compression, corresponds to a 25% loss in thermal efficiency for a coal plant.

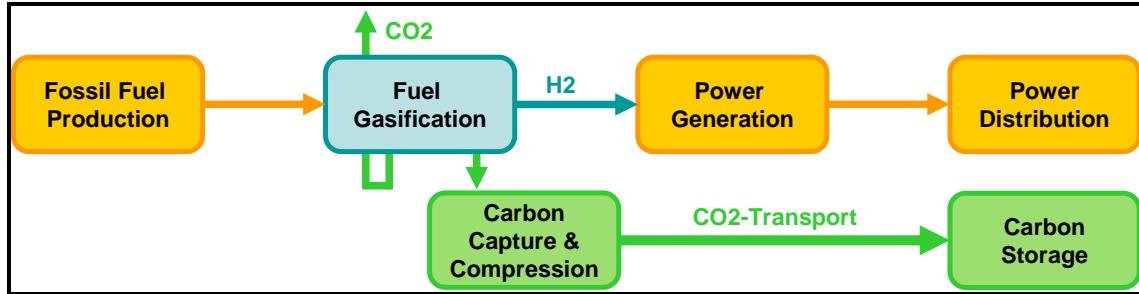
In summary, the obstacles to widespread adoption of post-combustion carbon capture are impurities in the flue gas, the handling of large volumes of gases, the handling of toxic chemicals, the high degree of efficiency losses of the power plant and the reduced ability to follow load changes.

1.1.2 Pre-combustion capture

Pre-combustion capture refers to the treatment of CO₂ and H₂ after the gasification process of coal, biomass or the steam reformation of natural gas (see Figure 2). CO₂ and H₂ can be separated by physical absorption, as the mixture of gases is under pressure and contains a high concentration of CO₂ (Table 1).

¹ A pilot plant that uses chilled ammonia to capture CO₂ 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

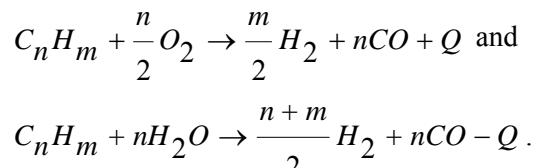


Source: Own illustration.

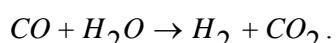
Decoupling the carbon separation from the electricity production offers some advantages. Plants can react to load changes more easily; the gasification process is best carried out in a continuous process, but a gas turbine in combination with hydrogen storage offers flexible utilisation of the power 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 H₂:



Second, the CO reacts with water to formulate CO₂ and H₂:



The synthesis gas (syngas) contains 35-40%_{vol} CO₂ (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 CO₂ 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 | Netherlands | 1993 | 253 | Coal and biomass co-firing |
| Sarlux plant | Italy | 2000 | 548 | Heavy hydrocarbons (TAR) |

Source: Own compilation from publicly available data.

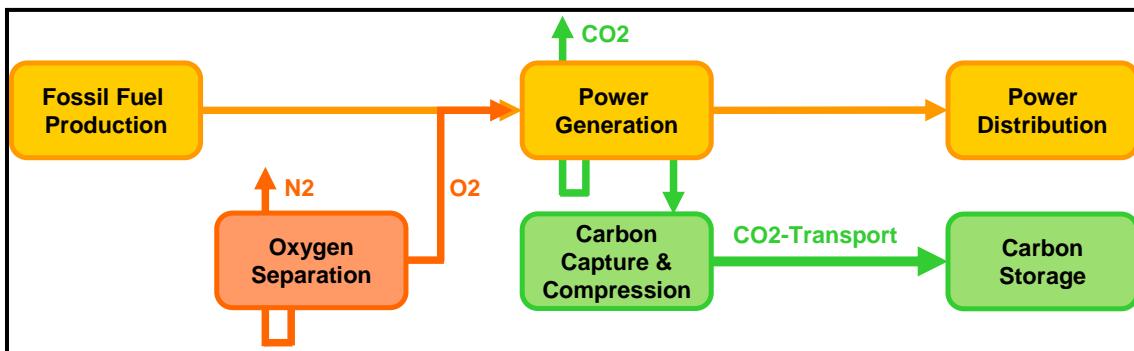
The chief barrier to deployment of IGCC technology is the high investment cost, i.e. between US\$1.2 and 1.6m per MW capacity excluding CO₂ capture and compression (US EIA, 2009). Yet even these cost estimations have proven unrealistic, since many IGCC coal projects have higher expenditures. An example is the US\$2.156 bn Mesaba Project (531 MW) (US DOE, 2010). For CO₂ 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 CO₂ is the combustion of fossil fuels in a pure oxygen and carbon dioxide atmosphere instead of ambient air (see Figure 3). CO₂ 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 CO₂ separation from the flue gas to the intake air results in a highly concentrated stream of CO₂ (up to 80%) after combustion. The remaining gas contains primarily H₂O. 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 CO₂ 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 O₂/CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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):

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

with the parameters defined in Box 1.

Box 1. Parameters in Equation (1)

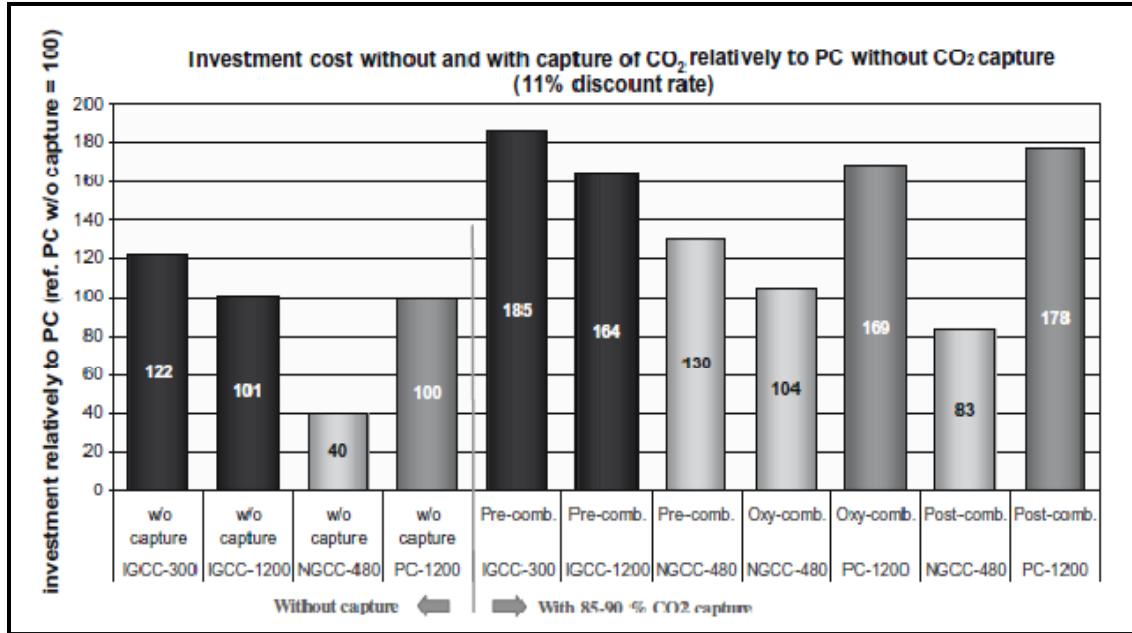
| | |
|-------------|--|
| C_{aba} | Abatement costs |
| C_{cap} | Capture costs |
| CE | Fraction of carbon captured |
| eff_{new} | Thermal efficiency of the CCTS plant |
| eff_{old} | Thermal efficiency of the standard plant |

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/tCO₂, the real abatement costs resulting from the higher fuel consumption are

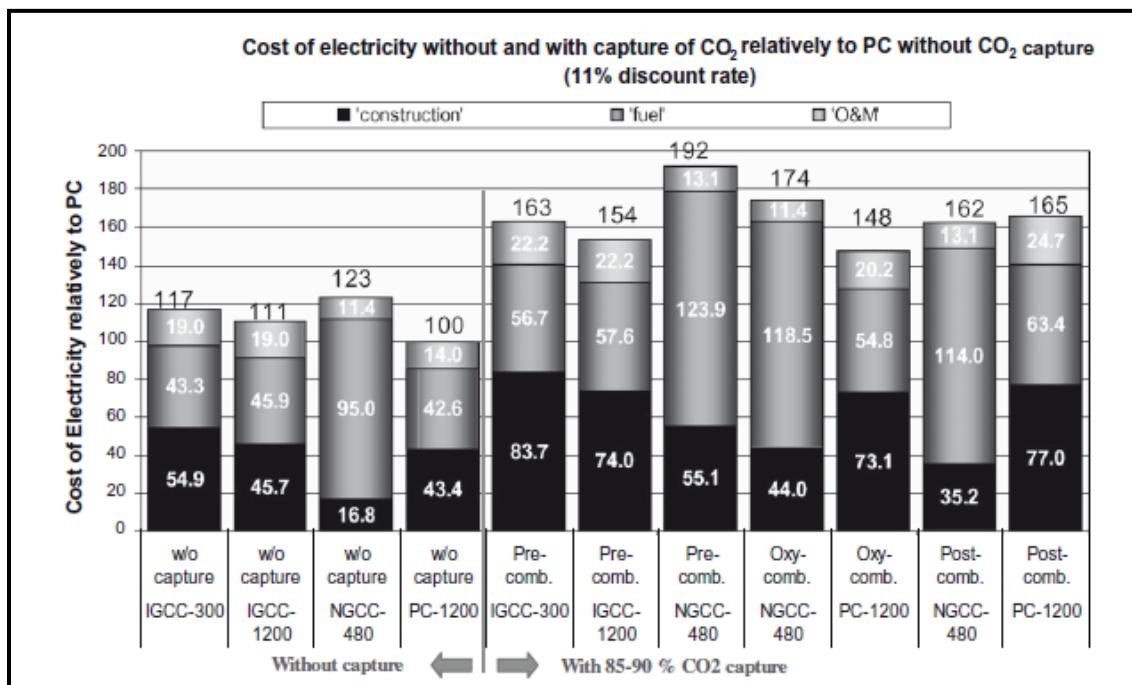
$$C_{aba} = 40\text{€} / tCO_2 * \frac{0.85}{[0.42 / 0.50 - (1 - 0.85)]} = 40\text{€} / tCO_2 * 1.23 \quad (2)$$

$$= 49.2 \text{ €} / tCO_2$$

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 CO₂ capture

Source: Kanniche et al. (2010).

Figure 5. Production costs (construction, fuel, operation and maintenance) of the different systems with and without CO₂ 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 CO₂ 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 CO₂ 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 CO₂ abatement costs by means of CCTS

| | € _{2000/tCO₂} | Time of operation | | | |
|------|-----------------------------------|-------------------|------|------|------|
| | | 2020 | 2030 | 2040 | 2050 |
| PC | € _{2000/tCO₂} | 42.6 | 41.2 | 39.6 | 40.1 |
| IGCC | € _{2000/tCO₂} | 42.6 | 37.4 | 36.8 | 37.3 |
| NGCC | € _{2000/tCO₂} | 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 CO₂ in lower quantities (<200 MtCO₂/yr in total) but qualify for CCTS (IEA, 2004) because of the higher concentrations of CO₂ 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 CO₂ 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).

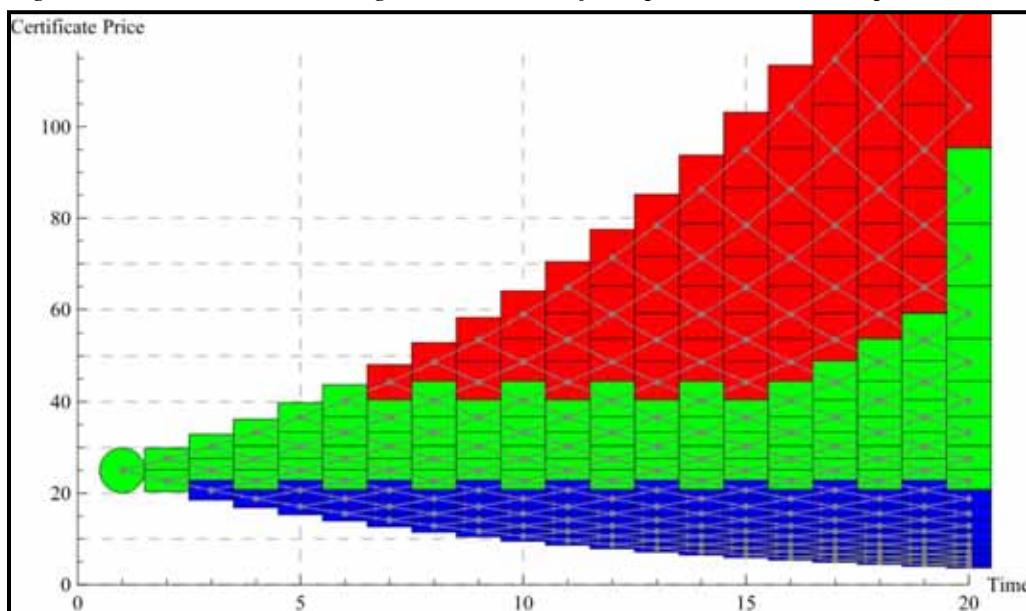
The extensive database available in work package 5.3.5 of the SECURE project (Herold and Hirschhausen, 2010) shows that amongst the 69 CO₂ capture projects worldwide, only 7 are operating and these are only on a pilot scale. Large-scale demonstration projects like SuperGen in the US and the tender in 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 CO₂ price and technological uncertainty

Geske and Herold (2010) conduct a dynamic stochastic investment analysis of CCTS retrofitting in an environment of CO₂ 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/tCO₂ (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: CO₂ transport via pipelines

CO₂ 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 CO₂ (375 kWh/tCO₂) is four times higher

than for liquid transport (96 kWh/tCO₂) (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 CO₂ pipelines were operating worldwide, transporting 50 Mt/yr (Wuppertal Institute, 2007).

Dry (moisture-free) CO₂ does not react to the carbon-manganese steel customarily used for pipe, even if the CO₂ contains contaminants. Moisture-laden CO₂, 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 CO₂ 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 CO₂ 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 CO₂ 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:

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

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

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

$$Q_{cf/d} = \frac{871 \cdot d_{inch}^{8/3} \sqrt{P_{D,psi}^2 - P_{S,psi}^2}}{\sqrt{l \text{ miles}}} \quad (5)$$

with the parameters defined in Box 2.

³ A typical coal-fired 1,000 MW plant emits about 13 ktCO₂/d (Vallentin, 2007).

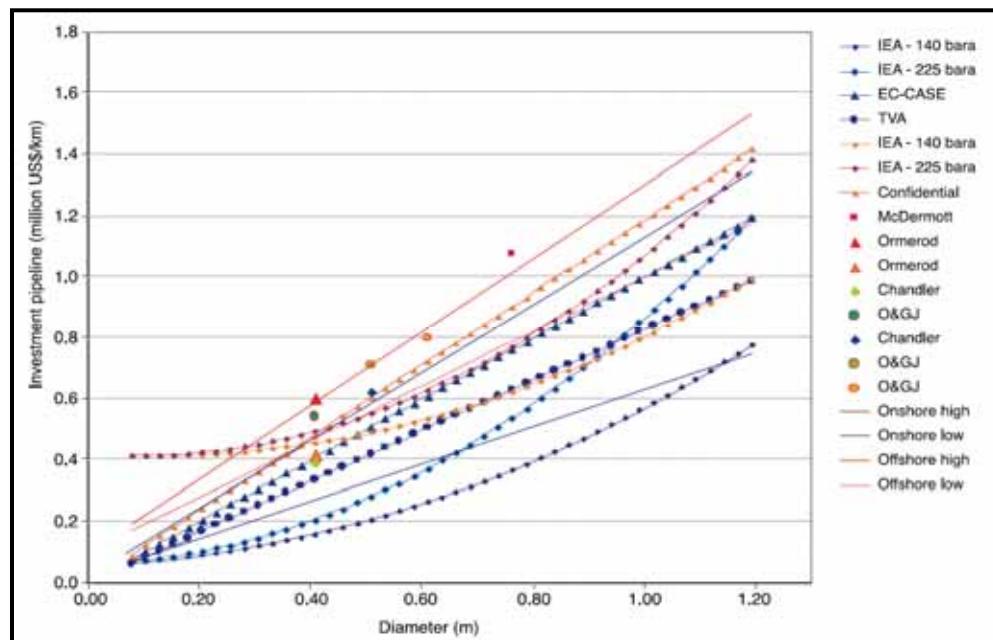
Box 2. Parameters in Equations (3) to (5)

| | |
|------------|--|
| 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 m ³ 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 disproportionately 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.

CO₂ 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 ($\pm 60\%$) and up to €1 mn ($\pm 40\%$) per km for pipelines with a nominal diameter of 200 mm (1,200 mm), respectively (see Figure 7).

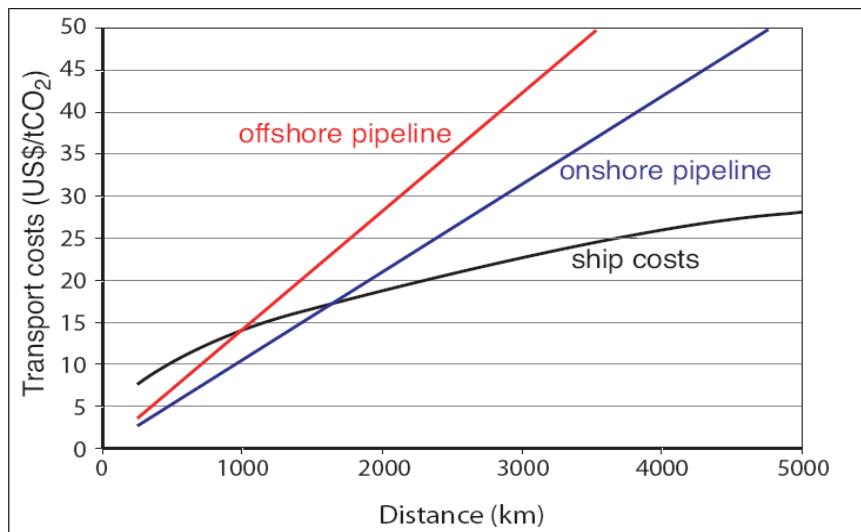
Figure 7. Pipeline investment cost estimates



Sources: IPCC (2005) (data derived from IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sary, 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, CO₂ transportation costs vary between less than €1 and more than €20/tCO₂, being a function of the transportation distance (i.e. 100 to 1,500 km) and the CO₂ mass flow.

Figure 8. CO₂ transport cost comparison: On-/offshore pipeline vs. shipping transport



Notes: Pipeline costs are given for a mass flow of 6 MtCO₂/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. CO₂ 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 CO₂ 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 CO₂ 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 CO₂.

Decision-making about the trade-offs between point-to-point and meshed CO₂ 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 CO₂ 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: CO₂ 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 CO₂ 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

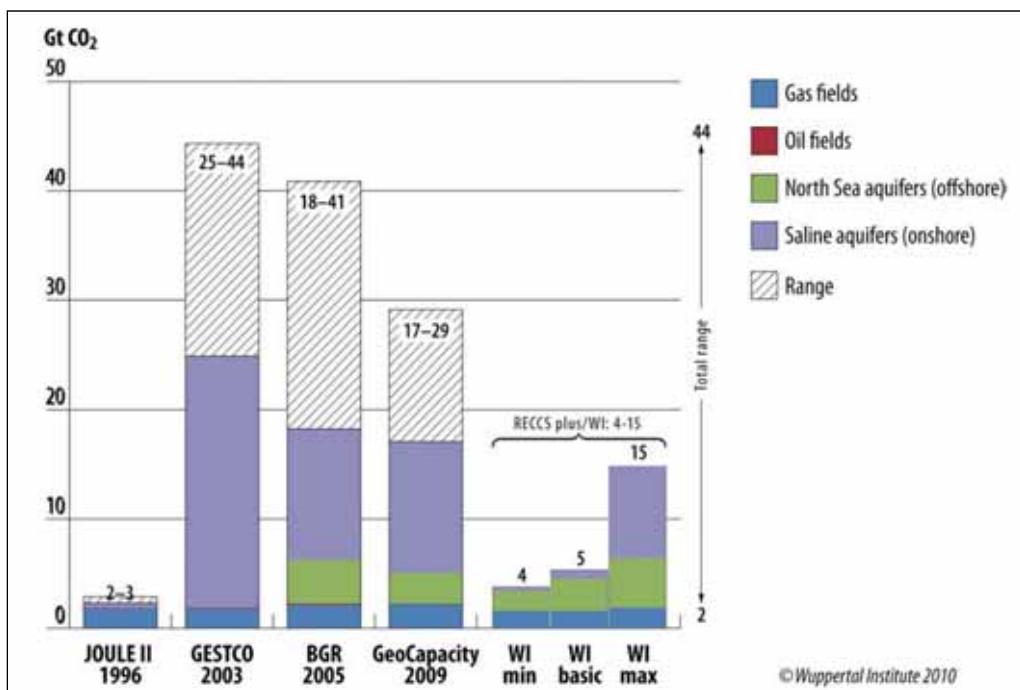
Conventional oil production yields only a fraction of the original oil in place in a specific oil field. When this method is exhausted and the production rates are in decline, water (secondary recovery) and CO₂ floods (tertiary recovery), amongst other measures, may be used to increase production. The two techniques for CO₂ flooding are miscible and immiscible. In *miscible* CO₂ floods, CO₂ 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 CO₂ may break through. Therefore, water and CO₂ are usually injected by turns in a so-called 'water alternating gas' process to create a barrier of water for both the CO₂ and oil. In

immiscible CO₂ floods, the CO₂ is pumped underground at lower than MMP and pushes the oil towards the production wells. In both cases, a significant part of the CO₂ 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 GtCO₂ (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 CO₂ 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 CO₂ storage capacity for Germany

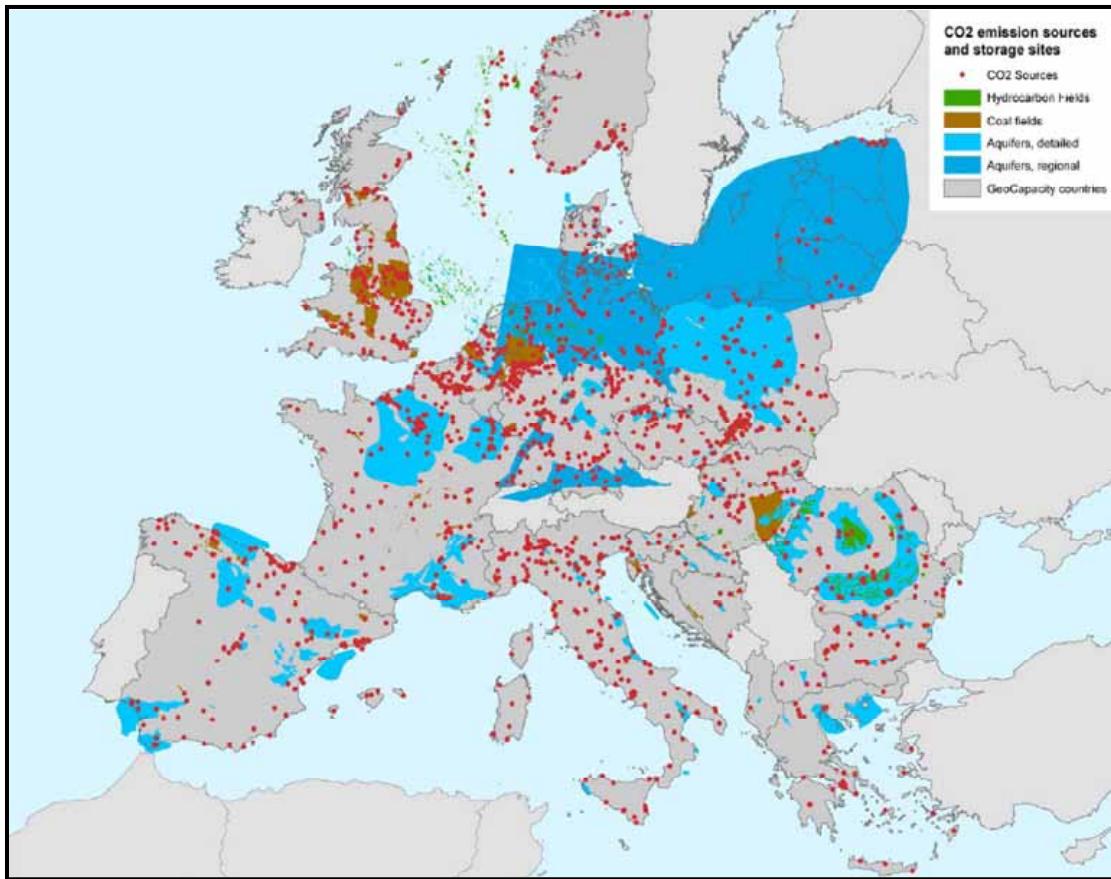


Source: Wuppertal Institute (2010).

Figure 10 shows estimations of the geographical distribution of CO₂ sinks and sources in Europe. Storage in saline aquifers appears to offer the greatest potential, followed by coal seams. Enhanced coal-bed methane (ECBM) recovery⁵ is aimed at deep coal seams that cannot be exploited at reasonable cost. One barrier is that the swelling of coal after the CO₂ injection reduces permeability and thus the amount of CO₂ that can be injected.

⁵ China is interested in ECBM because of the possible extraction of methane (natural gas) by injecting CO₂ into the coal seam (Vallentin, 2007).

Figure 10. Estimated CO₂ 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 MtCO₂. 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 CO₂ 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

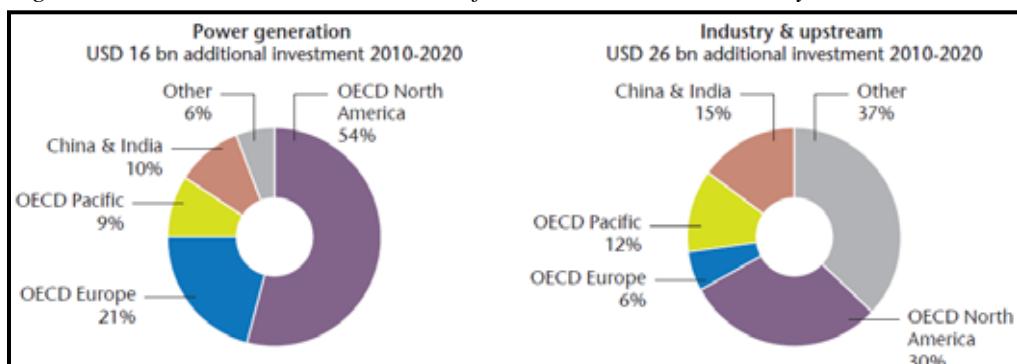
The IEA (2009) has published a roadmap with detailed milestones for the key developments in CCTS needed to achieve the overall goal of halving the annual CO₂ emissions of 2005 in 2050. Meeting the overall CO₂ reduction targets requires 3,400 projects worldwide until 2050, which altogether demand investments 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 CO₂ 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 CO₂ 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 GtCO₂ will be required in 2020.

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



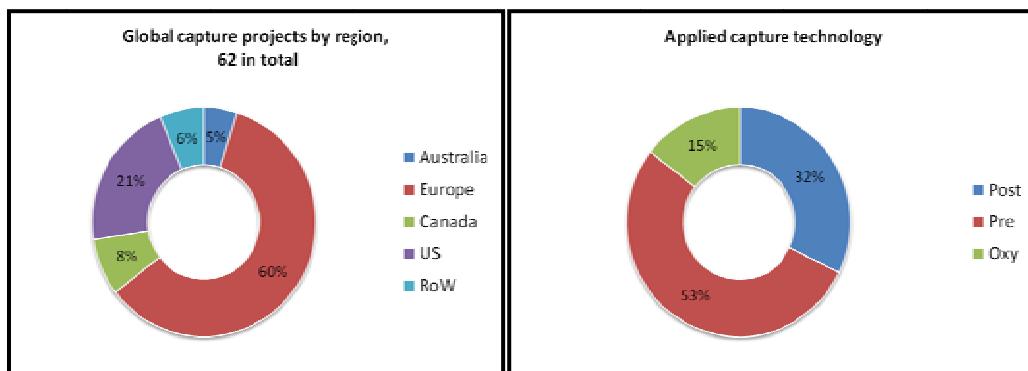
Source: IEA (2009).

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 CO₂ 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 CO₂ capture projects and technologies



Source: Own illustration.

2.3 The US CO₂ pipeline network

The US is sometimes cited as a benchmark for Europe. Hence we add some empirical experience of the development of CO₂ 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 CO₂ miscible floods was the SACROC unit in the Permian Basin in Texas. From January 1972, it accepted CO₂ 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 CO₂ transported to the Permian Basin via the Cortez (808 km) and Bravo

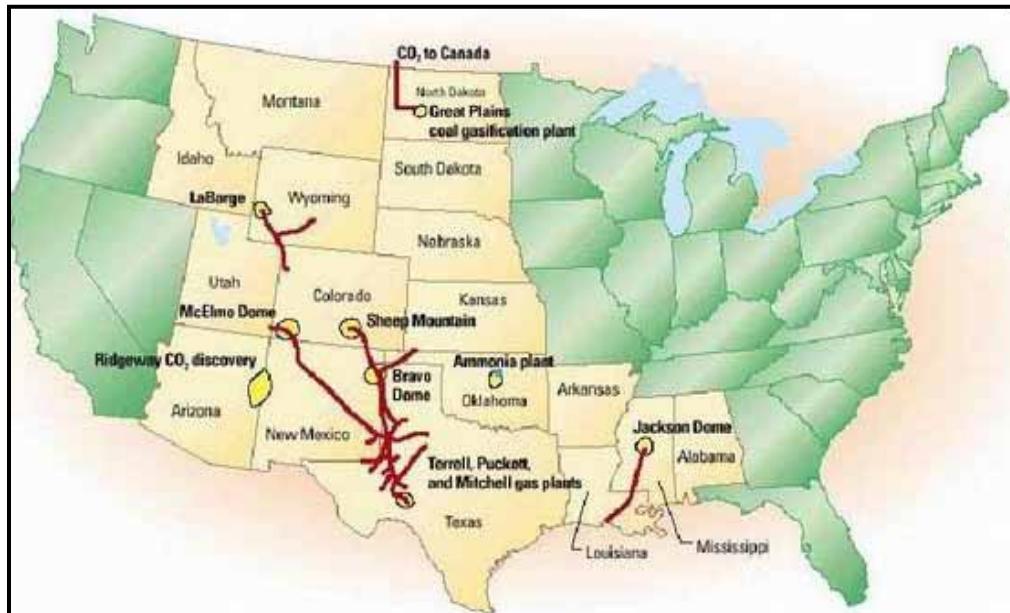
(351 km) pipelines (see Figure 13). Other mature oil fields were gradually connected to create a large cluster of CO₂ EOR operations in the Permian Basin. Today, the major sources are the McElmo Dome and Doe Canyon (966 MMcf/d) in Colorado, Bravo Dome (290 MMcf/d) in New Mexico and Sheep Mountain (40 MMcf/d) in Colorado, and several natural gas processing plants to the south of the Permian Basin that connect via the Val Verde Pipeline (75 MMcf/d), for a total of 1,371 MMcf/d, or 26.6 Mt/a (see Moritis, 2008 and Table 6). CO₂ availability limits the expansion of EOR operations in the basin and several companies are seeking to increase the availability of CO₂ with new pipelines.

Naturally occurring CO₂ resources are usually discovered when prospecting for natural gas. To produce the CO₂, 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 CO₂ source thus does not much differ from developing a natural gas field. The cost structure of CO₂ 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 MMcf/d). The total increase of CO₂ production capacity through the investments is 300 MMcf/d (about 5.8 Mt/a).

The other major operations in North America are the Weyburn CO₂ Monitoring and Storage Project, which captures about 2.9 Mt of CO₂ 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 CO₂ from the Jackson Dome in Mississippi and from projects in Wyoming and Oklahoma. US oil production from CO₂ 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 CO₂ transmission network



Source: European Energy Forum (2010)

Table 6. Major CO₂ 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 CO₂ is sequestered due to the tax on the CO₂ content of natural gas (see Table 7). The other major pipelines deliver CO₂ for application in secondary or tertiary oil recovery. Four pipelines transport CO₂ from industrial sources – gas processing and synfuel plants or a natural gas liquefaction facility. The other 15 pipelines are used for CO₂ from geological sources. Although insufficient data limit researchers' ability to understand the general structure of the sector, data on CO₂ 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 CO₂ 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 CO₂ pipeline network will differ substantially from that in the US. First, the positive experience with CO₂ 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 stored⁶ 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 CO₂ sources coupled with the increased need for suitable storage will require a well-designed network with large backbone pipelines.

As we have noted, CO₂ 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 CO₂ 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 CO₂ 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 CO₂.

3. Modelling future CO₂ 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 CO₂ 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.

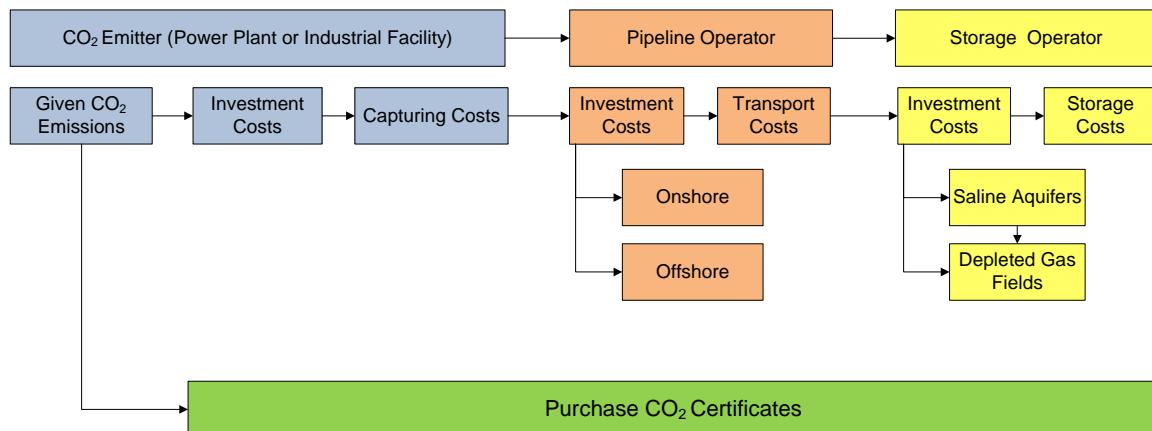
⁶ Under normal conditions, only about 30% of the injected CO₂ remains underground. The rest is brought up with the oil, and then separated and re-injected.

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 CO₂ 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 CO₂ 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 CO₂ 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 *CO₂ 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 CO₂ 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 CO₂ certificate price in Europe is another economic and political uncertainty influencing CCTS deployment. We implement various linear CO₂ certificate price paths to examine the volatility of CCTS to CO₂ certificate price developments.

Rapid and broad deployment of CCTS technology will greatly depend on the public’s opinion of CO₂ 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 CO₂ 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, CO₂ 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

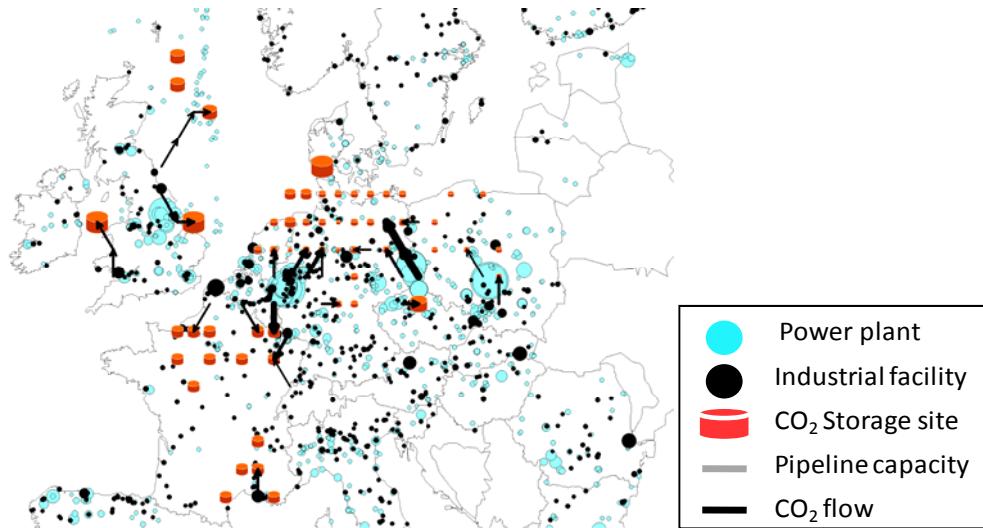
| Scenario | CO ₂ price in 2050 (€tCO ₂) | CO ₂ stored via CCTS in 2050 (%) | Annual storage rate exceeds 100 MtCO ₂ /a* | Pipeline infrastructure longer than 1,200 km* | Infrastructure length in 2050 (km) | Share of CO ₂ from industry (%) |
|--------------------------------|--|---|---|---|------------------------------------|--|
| 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).

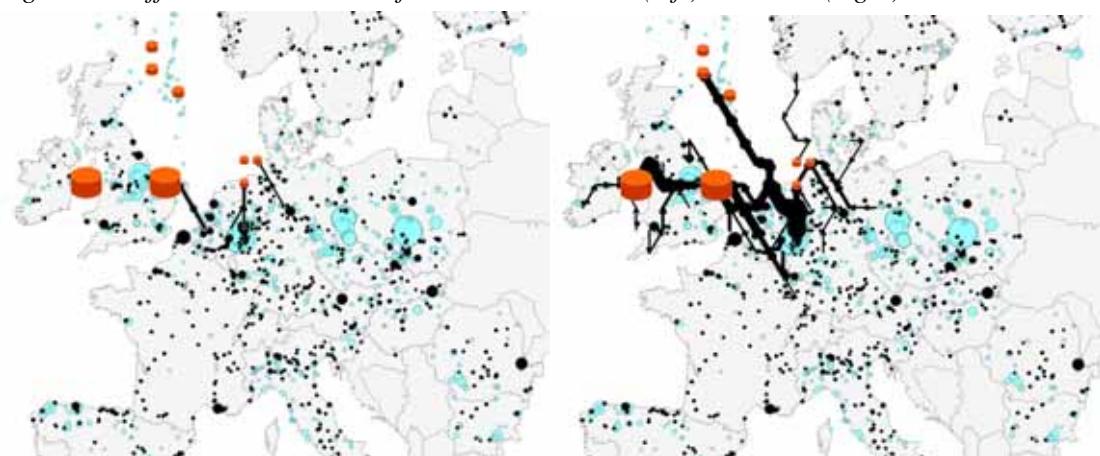
The results indicate that CCTS can theoretically contribute to the decarbonisation of Europe's energy and industry sectors. This requires a CO₂ certificate price rising to €55/tCO₂ in 2050, and sufficient CO₂ storage capacity available for both on- and offshore sites. Yet, CCTS deployment is highest in CO₂-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 CO₂ prices will significantly reduce the role of CCTS as a CO₂ mitigation technology, especially in the energy sector. Continued public resistance to onshore CO₂ 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 CO₂ 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 CO₂ and the ability to transport and geologically store CO₂ safely underground. In power installations, CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂. 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 CO₂ 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 (Groenengen 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 (Groenengen 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 (Groenengen 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 CO₂ capture, unresolved institutional and regulatory issues in CO₂ 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 CO₂ 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 CO₂ 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 |

Bibliography

- Abercrombie, N. (2009), “New economic recovery funding helps to address global climate change”, Office of the Clerk, US House of Representatives, Washington, D.C. (<http://abercrombie.house.gov/2009/05/spot09carbon-capture-funding.shtml>).
- Advanced Resources International (2006), *Undeveloped domestic oil resources: The foundation for increasing oil production and a viable domestic oil industry*, Report prepared for the US Department of Energy Office of Fossil Energy – Office of Oil and Natural Gas, Advanced Resources International, Washington, D.C., February.
- Ansolabehere, S., J. Beer, J. Deutsch, D. Ellerman, J. Friedmann, H. Herzog, H.D. Jacoby et al. (2007), *The Future of Coal*, Technical Report, MIT, Cambridge, MA.
- Apotheker, D.F. (2007), “The design of a regulatory framework for a carbon dioxide pipeline network”, Master’s Thesis, Delft University of Technology.
- Australian Government (2009), “CCS Flagship Projects Short-listed”, Department of Resources, Energy and Tourism, Canberra (<http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/CCSFLAGSHIPPROJECTSSHORT-LISTED.aspx.html>).
- Bachu, S. (2008), “CO₂ storage in geological media: Role, means, status and barriers to deployment”, *Progress in Energy and Combustion Science*, Vol. 34, No. 2, April, pp. 254-273.
- Boeuf, P. (2003), “Public–private partnerships for transport infrastructure projects”, Contribution to the seminar, “Transport infrastructure development for a wider Europe” in Paris, 27-28 November.
- Bormann, J. and J. Finsinger (1999), *Markt und Regulierung*. Munich, Vahlen (in German).
- Boyd, P.W. and R. Strezepek (2000), “The Evolution and Termination of an Iron-Induced Mesoscale Bloom in the Northeast Subarctic Pacific”, *Limnology and Oceanography*, Vol. 50, No. 6, pp. 1872-1886.
- Buhre, B.J.P., L.K. Elliott, C.D. Sheng, R.P. Gupta and T.F. Wall (2005), “Oxy-fuel combustion technology for coal-fired power generation”, *Progress in Energy and Combustion Science*, Vol. 31, pp. 283-307.
- Butler, L. and K. Neuhoff (2005), *Comparison of Feed-in Tariff, Quota and Auction Mechanisms to Support Wind Power Development*, CMI Working Paper 70, Cambridge–MIT Institute, Cambridge, MA.
- Celia, M.A., S. Bachu and S. Gasda (2002), *A Framework to Estimate CO₂ Leakage Associated with Geological Storage in Mature Sedimentary Basins*, American Geophysical Union, Fall Meeting.
- Chrysostomidis, I., P. Zakkour, M. Bohm, E. Beynon, R. de Filippo and A. Lee (2009), “Assessing issues of financing a CO₂ transportation pipeline infrastructure”, *Energy Procedia*, Vol. 1, No. 1, pp. 1625-1632.
- Climate Action Network (CAN) Europe (2003), “Climate Technology Sheet 2: Pre-Combustion Carbon Capture”, CAN Europe, Brussels.
- Dardea, V., K. Thomsena, W. Wellb, H. Erling and E. Stenbya (2009), “Chilled ammonia process for CO₂ capture”, *Energy Procedia*, Vol. 1, No. 1, pp. 1035-1042.

- Dahl, H.J. and P. Osmundsen (2002), "Cost Structure in Natural Gas Distribution", *Conference Proceedings, Annual Conference for International Association for Energy Economics*, Aberdeen, 26-28 June.
- Dahowski, R.T., J.J. Dooley, C.L. Davidson, S. Bachu, N. Gupta and J. Gale (2007), "A North American CO₂ Storage Supply Curve: Key Findings and Implications for the Cost of CCS Employment", *Proceedings of the Fourth Annual Conference on Carbon Capture and Sequestration*, Alexandria, VA, 2-5 May.
- Dietz, J. and P. Michaelis (2004), *Incentives for Innovation in Pollution Control: Emission Standards Revisited*, Department of Economics, University of Augsburg.
- Dooley, J.J., S.H. Kim, J.A. Edmonds and M.A. Wise (2003), *A First Order Global Geological CO₂ Storage Potential Supply Curve and Its Application in a Global Integrated Assessment Model*, Joint Global Change Research Institute, University of Maryland.
- Ecofys (2004), *Global Carbon Dioxide Storage Potential and Costs*, Ecofys, Utrecht.
- Edenhofer, O., C. Carraro, C., Hourcade, J-C., Neuhoff, K. (2009), *RECIPE: The Economics of Decarbonization*, Report on Energy and Climate Policy in Europe, Potsdam Institute for Climate Impact Research, Potsdam.
- Ekström, C., F. Schwendig, O. Biede, F. Franco, G. Haupt, G. de Koeijer, C. Papapavlou and P.E. Røkke (2009), "Techno-Economic Evaluations and Benchmarking of Pre-combustion CO₂ Capture and Oxy-fuel Processes Developed in the European ENCAP Project", *Energy Procedia*, Vol. 1, No. 1, pp. 4233-4240.
- European Commission (2003), *Guidelines for successful public-private partnerships*, Directorate-General for Regional Policy, Brussels, March.
- (2009), "Selection of offshore wind and carbon capture and storage projects for the European Energy Programme for Recovery", MEMO/09/543, Brussels, 9 December.
- European Energy Forum (2010), "CO₂ Capture and Storage – Part of the Solution to the Climate Change Problem?", European Energy Forum, Brussels, 12 February (<http://www.europeanenergyforum.eu/archives/european-energy-forum/environmental-matters/co2-capture-and-storage-2013-part-of-the-solution-to-the-climate-change-problem>).
- European Environment Agency (EEA) (2007), *The European Pollutant Release and Transfer Register*, EEA, Copenhagen.
- Figueiredo, M.A. de, H.J. Herzog, P.L. Joskow, K.A. Oye and D.M. Reiner (2007), □Regulating Carbon Dioxide Capture and Storage, Working Paper 07-003, MIT Center for Energy and Environmental□Policy□Research, MIT, Cambridge, MA, April.□
- Fischer, C. (2007), "Emission pricing, spillovers, and public investment in environmentally friendly technologies", *Energy Economics*, Vol. 30, No. 1, pp. 487-502.
- FutureGen Alliance (2010), "FutureGen Alliance Takes Steps to Move Forward on FutureGen 2.0", Press release, FutureGen Alliance, 31 August (http://www.futuregenalliance.org/news/releases/pr_08-31-10.pdf).
- GeoCapacity (2009), "Estimated CO₂ Sinks and Sources in Europe", GeoCapacity Project, Geological Survey of Denmark and Greenland, Copenhagen.
- Gerling, J.P. (2010), "CO₂-Storage – German and International Perspective", Presentation at the "Berlin Seminar on Energy and Climate", at DIW Berlin, 3 June.

- Geske, J. and J. Herold (2010), *Carbon Capture and Storage Investment and Management in an Environment of Technological and Price Uncertainties*, Working Paper WP-RD-05, Dresden University of Technology.
- Government of Alberta (2010), “Carbon Capture and Storage”, Energy, Edmonton (<http://www.energy.alberta.ca/Initiatives/1438.asp>).
- Groenenberg, H. and H. de Coninck (2008), *Technical support for an enabling policy framework for carbon dioxide capture and geological storage, Task 3: Incentivizing CO₂ capture and storage in the European Union*, Report for the Directorate-General Environment of the European Commission, ECN, Petten, the Netherlands.
- Grossman, S.J. and O.D. Hart (1986), “The Costs and Benefits of Ownership: A Theory of Vertical and Lateral Integration”, *Journal of Political Economy*, Vol. 94, No. 4, pp. 691-719.
- Hart, O. and J. Moore (1990), “Property Rights and the Theory of the Firm”, *Journal of Political Economy*, Vol. 98, No. 6, pp. 1119-1158.
- Hazeldine, S. (2009), “UK CCS competition ‘dead on its feet’ says expert”, *Businessgreen.com* (<http://www.businessgreen.com/business-green/news/2252733/uk-ccs-competition-dead-feet>).
- Hemmelskamp, J. (2000), *Environmental Taxes and Standards: An Empirical Analysis of the Impact on Innovation-oriented Environmental Regulation*, Heidelberg/New York, NY: Physica Verlag.
- Herold, J. and C. von Hirschhausen (2010), *Carbon Capture, Transport, and Sequestration (CCTS) – The Real Threat to European Supply Security with Coal*, SECURE Work Package 5.3.5, DIW, Berlin.
- Herold, J., S. Rüster and C. von Hirschhausen (2010), “Vertical Integration along the Extended Value Added Chain Including Carbon Capture, Transport, and Sequestration (CCTS)”, Paper prepared for Project No. 213744, SECURE Work Package 5.3.2.
- Herzog, H.J. and D. Golomb (2004), “Carbon Capture and Storage from Fossil Fuel Use” in C.J. Cleveland (ed.), *Encyclopedia of Energy*, New York, NY: Elsevier Science Inc.
- Intergovernmental Panel on Climate Change (IPCC) (2005), *IPCC Special Report on Carbon Dioxide Capture and Storage*, Cambridge: Cambridge University Press.
- International Energy Agency (IEA) (2001), “Technology Status Report Zero Emissions Technologies for Fossil Fuels”, presented at the “IEA WPFF Zero Emission Technology Strategy Initiative Workshop on Technology Status & Perspectives” in Oslo, 14 January.
- (2004), *Prospects for CO₂ Capture and Storage*, Energy Technology Analysis, OECD/IEA, Paris.
- (2006a), *World Energy Outlook*, OECD/IEA, Paris.
- (2006b), *Prospects for CO₂ Capture and Storage*, Energy Technology Analysis, OECD/IEA, Paris.
- (2007), “World Energy Outlook 2007: Fact Sheet – Global Energy Demand”, IEA, Paris.
- (2008), *CO₂ Capture and Storage: A key carbon abatement option*, Energy Technology Analysis, OECD/IEA, Paris.
- (2009), *Technology Roadmap – Carbon Capture and Storage*, OECD/IEA, Paris.

- Jaffe, A.B., R.G. Newell and R.N. Stavins (2005), "A tale of two market failures: Technology and environmental policy", *Ecological Economics*, 54/2005, pp. 164-174.
- Jones, K. (2007), "Industry Director Directive #1 on Enhanced Oil Recovery Credit", Memorandum, US Department of the Treasury, Internal Revenue Service, Washington, D.C., 2 May.
- Kanniche, M., R. Gros-Bonnivard, P. Jaud, J. Valle-Marcos, J.M. Amann and C. Bouallou (2010), "Pre-combustion, post-combustion and oxy-combustion in thermal power plant for CO₂ capture", *Applied Thermal Engineering*, Vol. 30, pp. 53-62.
- Kinder Morgan (2009), Form 10-K, Annual Report for the fiscal year ended 31 December 2008, Kinder Morgan, Houston, TX (<http://www.secinfo.com/dUUaj.s1r.htm>).
- (2010), "Kinder Morgan CO₂", Kinder Morgan, Houston, TX (<http://www.kindermorgan.com/>).
- Kothandaraman, A., L. Nord, O. Bolland, H.J. Herzog and G.J. McRae (2009), "Comparison of solvents for post-combustion capture of CO₂ by chemical absorption", *Energy Procedia*, Vol. 1, No. 1, pp. 1373-1380.
- Laffont, J.-J. and D. Martimort (2002), *The Theory of Incentives: The Principal-Agent Model*, Princeton, NJ: Princeton University Press.
- Lee, D.S., D.H. Shin, D.U. Lee, J.C. Kim and H.S. Cheigh (2001), "The Use of Physical Carbon Dioxide Absorbents to Control Pressure Buildup and Volume Expansion of Kimchi Packages", *Journal of Food Engineering*, Vol. 48, No. 2, pp. 183-188.
- Linßen J. (et al.) (2006), Zukünftige Energieversorgung unter dern Randbedingungen einer großtechnischen CO₂-Abscheidung und Speicherung [Report], – Jülich: Forschungszentrum Jülich.
- Newbery, D., D. Reiner, T. Jamasb, R. Steinberg, F. Toxvaerd and P. Noel (2009), *Carbon Capture and Storage (CCS), Analysis of Incentives and Rules in a European Repeated Game Situation*, EPRG Report to DECC, University of Cambridge.
- Massachusetts Institute of Technology (MIT) (2004), *The Future of Coal*, Laboratory for Energy and the Environment, MIT, Cambridge, MA.
- McAllister, E.W. (2005), *Pipeline Rules of Thumb Handbook*, 6th Edition, Oxford: Elsevier.
- Mellzer, S.L. (2007), "The 'Nuts and Bolts' of CO₂ Enhanced Oil Recovery", presented at "A 1-Day Workshop Offered in Association with the Enhanced Oil Recovery", 25 October, Casper, Wyoming.
- Mendelevitch, R., P.Y. Oei, A. Tissen and J. Herold (2010), *CO₂ – Highways – Modeling Aspects of a Future CO₂ Transport Infrastructure*, DIW Discussion Paper 1052, DIW, Berlin.
- Mimura, T., Y. Yasuyuki, N. Takashi, I. Masaki and R. Ryuji (2003), "Development and Application of Flue Gas Carbon Dioxide Recovery Technology by Chemical Absorption Method", *Proceedings of the International Conference on Power Engineering: ICOPE*, 2003(2).
- Montero, J.P. (2002), "Permits, Standards, and Technology Innovation", *Journal of Environmental Economics and Management*, Vol. 44, No. 1, pp. 23-44.
- Moritis, G. (2001), "Future of EOR & IOR", *Oil & Gas Journal*, Vol. 99, No. 20, pp. 68-73.

- (2008), “More US EOR projects start but EOR production continues to decline”, *Oil & Gas Journal*, Vol. 106, No. 15, p. 41.
- Motta, M. (2004), *Competition Policy – Theory and Practice*, Cambridge, MA: Cambridge University Press.
- Oldenburg, C.M. (2003), *Carbon Sequestration in Natural Gas Reservoirs: Enhanced Gas Recovery and Natural Gas Storage*, Earth Sciences Division, Lawrence Berkeley National Labour Laboratory, Berkeley, CA.
- Rai, V., G.V. David and M. Thurber (2009), *Carbon Capture and Storage at Scale: Lessons from the Growth of Analogous Energy Technologies*, Working Paper No. 81, Program on Energy and Sustainable Development, Stanford University, CA.
- Reed, S. (2004), “The History of Oil Pipeline Regulation”, Federal Energy Regulatory Commission, Washington, D.C., 18 May.
- Reinganum, J.F. (1983), “Technology adoption under imperfect information”, *Bell Journal of Economics*, Vol. 14, No. 1.
- Reis, A.B. and D.A. Traca (2008), “Spillovers and the competitive pressure for long-run innovation”, *European Economic Review*, Vol. 52, No. 4, pp. 589-610.
- Resolute Energy Corporation (2006), “Carbon Dioxide Sale and Purchase Agreement”, *SECinfo*, 1 July (<http://www.secinfo.com/dsvr4.sTT5.v.htm>).
- (2007), “Product Sale and Purchase Contract”, *SECinfo*, 1 July (<http://www.secinfo.com/dsvr4.sTT5.u.htm#1stPage>).
- Reuters (2010a), “EU recommends winners of CCS project funding”, *Reuters*, 16 October (<http://www.reuters.com/article/idUKLG28841420091016>).
- (2010b), “Genesis Energy, L.P. Completes Transactions with Denbury Resources”, Press release by Genesis Energy and Denbury Resources Inc., *Reuters*, 2 June (<http://www.reuters.com/article/idUS109548+02-Jun-2008+BW20080602>).
- Rezvani, S., Y. Huang, D. McIlveen-Wright, N. Hewitt, and J. Deb Mondol (2009), “Comparative assessment of coal fired IGCC systems with CO₂ capture using physical absorption, membrane reactors and chemical looping”, *Fuel*, Vol. 88, No. 12, pp. 2463-2472.
- Rubin, E.S., M.S. Taylor, S. Yeh and D.A. Hounshell (2004), “Experience Curves for Power Plant Emission Control Technologies”, *International Journal of Energy Technology and Policy*, Vol. 2, Nos. 1/2, pp. 52-68.
- Rubin, E.S., S. Yeh, M. Antes, M. Berkenpas and J. Davison (2006), “Estimating future costs of CO₂ capture systems using historical experience curves”, in *Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies (GHGT-8)* in Trondheim, 19-22 June, Østfold Research Foundation, Fredrikstad.
- Stern, N. (2006), *The Economics of Climate Change: The Stern Review*, Cambridge: Cambridge University Press.
- Stigler, G.J. (1951), “The Division of Labor is Limited by the Extent of the Market”, *Journal of Political Economy*, Vol. 59, No. 3, pp. 185-93.
- Tzimas, E. (2009), *The Cost of Carbon Capture and Storage Demonstration Projects in Europe*, European Commission, Joint Research Center, Institute of Energy, Luxembourg: Publications Office of the European Union.

- US Department of Energy (DOE) (2009), “Secretary Chu Announces \$2.4 billion in Funding for Carbon Capture and Storage Projects”, DOE, Washington, D.C., 15 May (<http://www.energy.gov/7405.htm>).
- US Energy Information Administration (EIA) (2009), *Electricity Market Module*, Report #:DOE/EIA-0554(2009), EIA, Washington, D.C., March.
- Vallentin, D. (2007), *Inducing the International Diffusion of Carbon Capture and Storage Technologies in the Power Sector*, Wuppertal Papers No. 162, Wuppertal Institute for Climate, Environment and Energy, Wuppertal.
- Viscusi, W.K., J.M. Vernon and J.E. Harrington Jr. (2005), *Economics of Regulation and Antitrust*, 4th Edition, Cambridge, MA: MIT Press.
- World Coal Institute (WCI) (2010), “Coal Statistics”, WCI, London.
- Williamson, O.E. (1975), *Markets and Hierarchies: Analysis and Antitrust Implications*, New York, NY: The Free Press.
- (1985), *The Economic Institutions of Capitalism – Firms, Market, Relational Contracting*, New York, NY: The Free Press.
- Wuppertal Institute (2007), *RECCS: Strukturell ökonomischer Vergleich regenerativer Energietechnologien mit Carbon Capture and Storage*, Wuppertal Institute for Climate, Environment and Energy, Wuppertal (in German).
- (2010), *RECCS plus: Comparison of Renewable Energy Technologies with Carbon Dioxide Capture and Storage, Update and Expansion of the RECCS Study 0329967/07000285*, Wuppertal Institute for Climate, Environment and Energy, Wuppertal.
- Zweigel, P. and E.G.B. Lindeberg (2003), “Leakage Rate – The Main Quality Criterion for Underground CO₂ Storage”, Oral presentation at the “Third Nordic Mini-symposium on Carbon Dioxide Capture and Storage”, Trondheim, 2-3 October.
- “2008 Worldwide EOR Survey” (2008), *Oil & Gas Journal*, Vol. 106, No. 15.

Appendix 1. 2040 cost estimations for CCTS power plants

Table A1.1 Cost estimates for fossil fuel plants without CO₂ 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/tCO₂

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

Table A1.2 Cost estimates for fossil fuel plants with CO₂ 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/tCO₂; 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 CO₂ capture in 2040

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

¹⁾ €15/tCO₂; 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 CO₂ 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 CO₂. 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 CO₂ 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 CO₂ 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 (CO₂ mineralisation, algae production, etc.) and CO₂ 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 CO₂ 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 MtCO₂ 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 MtCO₂ 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 MtCO₂ per year from nearby industry, the Hub was chosen because it is near potentially suitable storage sites and a large source region for CO₂ capture – the industrial centres of Kwinana and Collie.
- **CarbonNet Hub.** With the goal of sequestering 3-5 MtCO₂ 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 CO₂ 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 CO₂ sink and source and in many cases the midstream pipeline. As CO₂ 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 CO₂ into the atmosphere. Thus, the pipeline and the CO₂ source together should be regarded as an extension of the crude oil exploration and production value chain.

US CO₂ market players face risks similar to those in the natural gas market. High capital expenditures and sunk costs are incurred when developing CO₂ fields and pipeline construction requires continuous cash flows from CO₂ production and pipeline operation. Producers of natural CO₂ cannot readily sell their gas to a random buyer, since the number of oil fields connected by CO₂ pipelines is limited and the start-up of a CO₂ flood requires technical preparation. EOR operators on the other hand depend on a steady supply of CO₂ 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 CO₂ source and the pipeline, or the pipeline and the oil field where the CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ are needed to produce one incremental barrel of oil, so the cost of CO₂ in EOR operations constitutes about 20 to 35% of the sales revenue and is the most expensive part of CO₂ 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 (CO₂). Kinder Morgan delivers approximately 1.3 billion cubic feet per day of CO₂ through about 1,300 miles of pipelines.

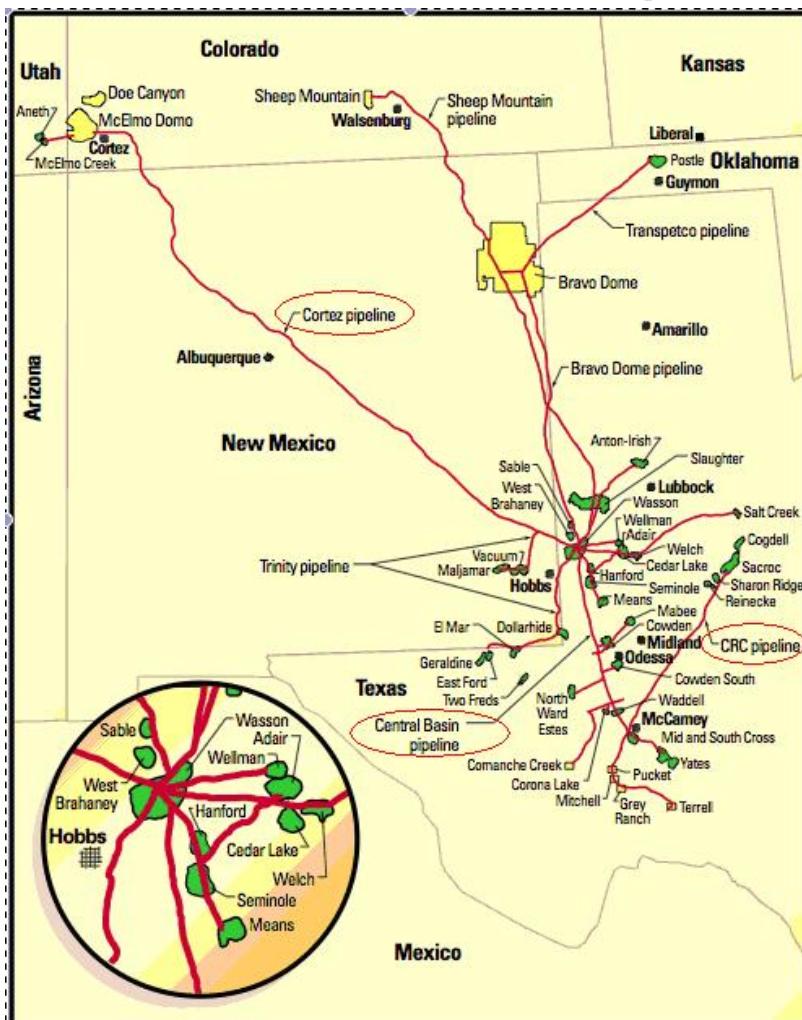
The map in Figure A3.1 presents KM's CO₂ pipeline network.

KM owns the two largest natural CO₂ fields in the US. The McElmo Dome, primarily owned by KM and ExxonMobil, produces up to 50 MMcf/d from 61 production wells. The Bravo Dome, with more than 10 tcf of CO₂, connects to the Denver City Hub via the Cortez pipeline (1 bcf/d to 4 bcf/d). From this hub more than 40 smaller pipelines distribute CO₂ 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 CO₂. In contrast to the European market, where storage capacity is scarce and there are limited incentives for network construction, the availability of CO₂ for storage (i.e. employed as a valuable commodity) is the scarce resource for which companies strive.

Figure A3.1 CO₂ pipelines for oil and gas reservoir sequestration used by Kinder Morgan



Source: Moritis (2001).

Ownership of the CO₂ transport network puts KM in a strong position when negotiating CO₂ prices. Yet CO₂ 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 CO₂ because the cost of the network represents the largest share of the CO₂ 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 CO₂ 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 CO₂ 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 CO₂ to Denbury's EOR operations. Denbury has exclusive use of the pipeline and must use it to supply CO₂ 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 CO₂ stream is less harmful to the business of an oil producer or CO₂ supplier. After CO₂ injection begins, it takes one to two years until oil production increases. Similarly, oil production does not cease when the CO₂ 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 CO₂ value-added chain, including injection into the oil field. For the supplier of CO₂, 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 ₂ pa | 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 | Sq 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 | – | – |
| Niederhausen | Germany | RWE | Coal | Pilot project | Post | – | 2009 | Operating | €9 mn | – |
| Brindisi | Italy | Enel and Eni | Coal | 242 | Post | Sq | 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 | Sq | (2013) 2015 | Construction | – | Reserve list, EEPR |
| Maasvlakte, Rotterdam | 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 | Sq | (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 | Sq | 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 Babcock, 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 CO₂ transport and storage projects

Table A5.1 International CO₂ (capture), transport and storage projects: CO₂ sources (part 1)

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

Table A5.1 cont'd

| | | | | | | | | | | |
|-----------|-------------------------------------|---|----|--|------------|--|-----------------------------------|-----|---|------------------------|
| 5a | Sheep Mountain (northern) | – | US | Sheep Mountain, Colorado | Geological | BP, ExxonMobil | 50 50 | Oxy | – | 1,343E+10 |
| 5b | Sheep Mountain (southern) | – | US | Sheep Mountain, Colorado Bravo Dome, New Mexico | Geological | BP, ExxonMobil Oxy, KM, Amerada Hess, multiple private | 50, 50 75 11, 10 4 | Oxy | – | 1,343E+10 8,056E+10 |
| 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 CO₂ (capture), transport and storage projects: CO₂ sources (part 2)

| | | | | CO ₂ Feedstock | | | | | | |
|-----|----------------------------------|----------|---------|---|--------------------------|--|-----|---|-----------------------|-----------------------------|
| No. | Project Name | Start-up | Country | Location | Type | Owners | (%) | Operator | Contracting structure | Reserves (Nm ³) |
| 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 Sonatrach 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 CO₂ (capture), transport and storage projects: CO₂ sources (part 3)

| No. | Project name | Start-up | Country | Location | Type | Owners | CO ₂ Feedstock | | Contracting structure | Reserves |
|-----------|----------------------------------|----------|-----------|--|--------------------------|----------------------------------|---------------------------|--------------------------------|--|----------|
| | | | | | | | (%) | Operator | | |
| 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 North West Upgrader | Industrial Industrial | Agrium North West Upgrading – | – | Agrium North West Upgrading | ‘Long-term CO ₂ supply agreement’ ‘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 Oxyfuel 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 Teollisuuden Voima | 55 45 | Fortum | - | - |

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 CO₂ (capture), transport and storage projects: CO₂ pipelines (part 1)

| No. | CO ₂ Transport | | | | | | | | | | | |
|-----|------------------------------|----------|---------|----------|--------------------------------|-----|--------------------------|-----------------------|---------------|----------|----------------|-------------------------------|
| | Project name | Start-up | Country | Type | Owners | (%) | Operator | Contracting structure | Distance (km) | Size (m) | Pressure (bar) | Capacity (Nm ³ /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 CO₂ (capture), transport and storage projects: CO₂ pipelines (part 2)

| No. | | | CO ₂ Transport | | | | | | | | | |
|-----|---|----------|---------------------------|----------|---|----------|---|-----------------------|---------------|------------|----------------|-------------------------------|
| | Project name | Start-up | Country | Type | Owners | (%) | Operator | Contracting structure | Distance (km) | Size (m) | Pressure (bar) | Capacity (Nm ³ /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 Sonatrach 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 CO₂ 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 CO₂ 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 CO₂ (capture), transport and storage projects: CO₂ pipelines (part 3)

| No. | CO ₂ Transport | | | | | | | | | | | | |
|-----|----------------------------------|----------|-----------|----------|----------------|-----|----------|-----------------------|---------------|-------------|----------------|-------------------------------|--|
| | Project name | Start-up | Country | Type | Owners | (%) | Operator | Contracting structure | Distance (km) | Size (m) | Pressure (bar) | Capacity (Nm ³ /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 Oxyfuel 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 CO₂ (capture), transport and storage projects: CO₂ sinks (part 1)

| No. | Project name | Start-up | Country | Type | Location | Owners | CO ₂ Sink | | | | | |
|-----|---------------------------|----------|---------|------|--|--|----------------------|----------|--------------------|-----------------------|-----------------------------------|--|
| | | | | | | | (%) | Operator | Start of operation | Contracting structure | Total capacity (Nm ³) | |
| 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 CO₂ (capture), transport and storage projects: CO₂ sinks (part 2)

| No. | | | CO ₂ Sink | | | | | | | | | |
|-----|----------------------------------|----------|----------------------|---------------|--|---------------------|-----|----------|--------------------|-----------------------|--|--|
| | Project name | Start-up | Country | Type | Location | Owners | (%) | Operator | Start of operation | Contracting structure | Total capacity (Nm ³) annual injection rate (MtCO ₂ pa) | |
| 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 Sonatrach 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 CO₂ (capture), transport and storage projects: CO₂ sinks (part 3)

| No. | | | CO ₂ Sink | | | | | | | | | |
|-----|--|-----------|----------------------|--------------------|-------------------------------|----------------|-----|----------------|--------------------|-----------------------|-----------------------------------|--|
| | Project name | Start-up | Country | Type | Location | Owners | (%) | Operator | Start of operation | Contracting structure | Total capacity (Nm ³) | |
| 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 Oxyfuel 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 ₂ pa |
| 41 | Otway | 2008 | Austria | Depleted gas reservoir (1,000 m) | – | CO ₂ CRC | – | – | – | – | 0.1 MtCO ₂ pa |

Source: Own compilation from various publicly available data.

About CEPS

Founded in Brussels in 1983, the Centre for European Policy Studies (CEPS) is among the most experienced and authoritative think tanks operating in the European Union today. CEPS serves as a leading forum for debate on EU affairs, but its most distinguishing feature lies in its strong in-house research capacity, complemented by an extensive network of partner institutes throughout the world.

Goals

- To carry out state-of-the-art policy research leading to solutions to the challenges facing Europe today.
- To achieve high standards of academic excellence and maintain unqualified independence.
- To act as a forum for discussion among stakeholders in the European policy process
- To provide a regular flow of authoritative publications offering policy analysis and recommendations.
- To build collaborative networks of researchers, policy-makers and business representatives across the whole of Europe.
- To disseminate our findings and views through our publications and public events.

Assets

- Multidisciplinary, multinational & multicultural research team.
- Complete independence to set its own research priorities and freedom from any outside influence.
- Seven research networks, comprising numerous other highly reputable institutes, to complement and consolidate CEPS' research expertise and to extend its outreach.
- An extensive membership base of Corporate and Institutional Members, which provide expertise and practical experience and act as a sounding board for CEPS policy proposals.

Programme Structure

Research Programmes

- Economic & Social Welfare Policies
- Financial Markets & Institutions
- Energy & Climate Change
- Regulatory Policy
- EU Foreign, Security & Neighbourhood Policy
- Justice & Home Affairs
- Politics & Institutions
- Agricultural & Rural Policy

Research Networks

- European Capital Markets Institute (ECMI)
- European Climate Platform (ECP)
- European Credit Research Institute (ECRI)
- European Network for Better Regulation (ENBR)
- European Network of Economic Policy Research Institutes (ENEPRI)
- European Policy Institutes Network (EPIN)
- European Security Forum (ESF)

CEPS organises a variety of activities, involving its members and other stakeholders in the European policy debate, including national and EU-level policy-makers, academics, corporate executives, NGOs and the media. Its funding is obtained from a variety of sources, including membership fees, project research, foundation grants, conferences fees, publication sales and an annual grant from the European Commission.

E-mail: info@ceps.eu
Website: www.ceps.eu