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Vertical Integration and Market Structure along the Extended Value Added Chain including Carbon Capture, Transport, and Sequestration (CCTS)

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Vertical Integration along the Carbon Capture and Sequestration (CCTS) Value Added Chain

Chair of Energy Economics and Public Sector Management, Dresden University of Technology (TUD)

This deliverable discusses the vertical structure oft he carbon capture, transport, and storage (CCTS) value-added chain in Europe. This is an important element of the European supply security with coal, because, as we argue more in-depth in deliverable 5.3.5, a sustainable energy future in Europe will rely on a well-functioning, extensive CCTS process. Whereas research and development in the fields of carbon capture and storage (CCS) is making progress with large-scale demonstration projects announced and started within the European the role of the transportation network, and the institutional structure of the value-added chain, have not been sufficiently analyzed.

Evidence from the US CO_2-transport sector indicates a high level of vertical integration in the absence of a supervising, regulatory institution and carbon prices. This structure may be efficient as long as storage sites are abundant and close to the emission sources, and the players involved share a common interest. Storage of CO_2 in the US takes place in oil fields, where it increases fossil fuel production and thus economic benefits. We take a deeper look into the sector by analyzing ownership structures of major enhanced oil recovery (EOR) projects in the US. We observe shared ownership or long-term contracts between oil producers and CO_2 producers which also control the transportation infrastructure, e.g. in the case of Kinder Morgan.

We argue that the situation in the U.S. can not be transposed directly to Europe, because it was based on two unique features: the economic benefits from EOR in the presence of low-cost CO_2 sources, and governmental support in form of tax credits. From a European perspective, those preconditions are not fulfilled and players along the carbon capture, transport and storage (CCTS) value chain are exposed to risks different from those experienced in the US. Power plant operators may prefer to switch off the capture unit in case of low carbon prices, while a storage operator could exhibit market power once a pipeline was built to ex-post renegotiate the conditions for storage. Given the high risk and uncertainty (e.g. about storage capacity and the future regulatory regime), we also expect a tendency towards vertical integration in a future European CO_2 transport sector. However, the efficiency of the future CO_2 transport network strongly depends on the dislocation of sinks and sources. As we do not expect a situation in which storage will take place close to the source, long distance, cross boarder, and even overseas transport will dominate. We therefore propose a common backbone CO_2 transport network which can help to keep overall costs for the industry low as well as ensuring non-discriminatory access to the network and storage sites.

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1 Introduction

Among the various options for the de-carbonization of the electricity sector, carbon capture, transport and storage (CCTS) holds the potential to become an effective instrument for the next decades. Within the three technological concepts being expected to reach market maturity until 2020, a carbon emission reduction between 70% and 80% over the fuel chain can be reached. However, there remain uncertainties, which are not only related to the underlying innovative technologies. Legal aspects form barriers to the application; the high capture costs, given the actual low price for carbon certificates, represent further challenges. For the European Union with its high share of coal and natural gas fired power plants, CCTS will be essential to comply with proposed emission reduction. If climate change is taken seriously, there can be no future for coal without CCTS.

Yet, the discussion on CCTS so far was mainly driven by technological concerns and economic aspects of the capture and storage process with little attention paid to the transportation of CO_2. Storage capacity involves a high level of uncertainty about where to store, how much to store and long-term safety aspects of the reservoirs. Capturing on the other hand involves the large scale application of still innovative, expensive technologies such as the oxy-fuel process, thus requiring additional effort in terms of research and development. Within the last few years, engineers and geologists became more and more confident that the CCTS technology will work and that the long-term storage of CO_2 is possible at costs and at quantities which offer an attractive alternative for CO_2 emission reduction within the next decades.

What is missing in this bright picture of CCTS is the CO_2 transportation network which until recently experienced only limited attention. This might be based on the fact that the transport of CO_2 is done for a couple of decades without any major technical problems in the US, as it is also the case for natural gas and oil transport. Thus, the technology is well known and cost estimations are credible.

Therefore, this SECURE-report focuses on the vertical structure of the sector, and the particular role of transportation theory. We draw both on the theories of institutional economics and industrial organization and on case studies to derive conclusions on the appropriate corporate structure for CCTS in Europe.

We build up a database of major CO_2 transport and storage projects in the US and analyze the motivation of the players to integrate or disintegrate vertically along the extended value chain including CO_2 production, transportation, and storage.

2 The CCTS Value Added Chain

Carbon capture, transport and storage (also called carbon capture and sequestration), defines a process in which CO_2 from large point sources such as fossil fuel power plants is captured, compressed, transported, and stored underground. Accordingly, CCTS can be seen as an instrument to mitigate the impact of fossil fuel combustion to the greenhouse gas effect and global warming. Three technological concepts are about to reach market maturity: Pre-combustion capture, the oxy-fuel process, and retrofitable post-combustion capture.

2.1 Capture

All CCTS technologies aim at creating a highly concentrated or pure stream of CO_2, ready for transportation to a storage side. Applicable technologies depend on the type of fuel and whether the fuel is combusted in a liquid, gaseous, or solid state..

2.1.1 Post-combustion capture

Post-combustion capture aims at separating the CO_2 out of the flue gas, comparable to flue gas desulphurization, which long has been instituted mandatory to clean SO_x emissions. Depending on the carbon content of the fuel and the amount of excess air, CO_2 reaches concentrations in the flue gas between 3% for natural gas up to 15% for pulverized coal (RECCTS, 2007). The CO_2 concentration determines which post combustion capture process can be applied. Two procedures are applicable.

First, the physical absorption with pressure-induced CO_2 recovery needs concentrations above $10\%_{vol}$, as the capacity and CO_2 selectivity of available adsorbents is low. Physical absorption takes place at high pressure on a solid absorbent (such as activated carbon or zeolites) and the CO_2 is released under normal atmospheric conditions (Dong et al., 2001).

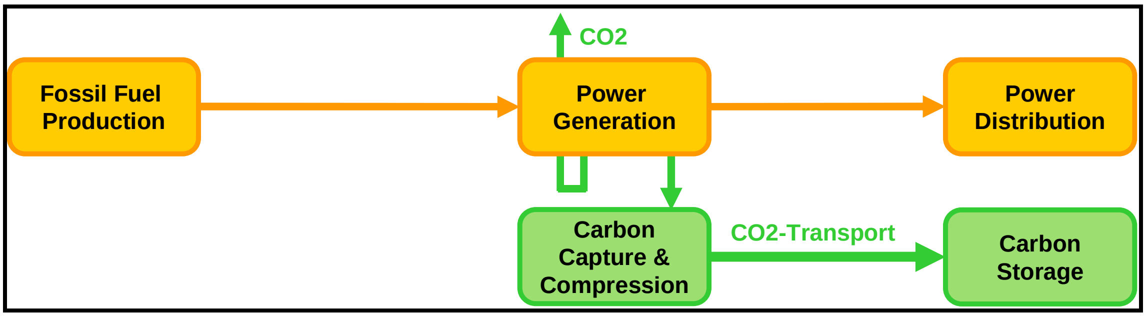
The chemical-absorption in combination with heat-induced CO_2-recovery is less sensitive to low concentration and partial pressure and is applicable to natural gas plants. In this process, CO_2 in the flue gas is chemically bounded by a monoethanolamin (MEA) or ammonia solution. The fundamental reaction for the MEA process is as follows:

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

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

Post combustion capture is an independent link in the process chain, making this technology specifically suitable for retrofitting existing power plants.

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



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2.1.2 Pre-combustion capture

Pre-combustion capture refers to the removal of the fuel embedded carbon in hydrocarbons to produce hydrogen which then combusts in a gas turbine. The hydrogen feedstock is gasified in a high-pressure, high-temperature gasifier with either oxygen or air and water vapor. The fundamental reactions are:

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

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

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

Second, the CO reacts with water to CO_2 and H_2

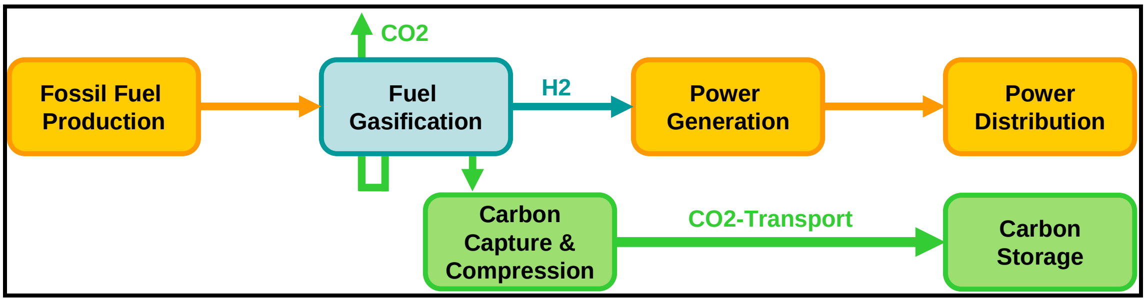
$$CO + H_2O \rightarrow H_2 + CO_2$$

The syntheses gas contains 35-40%$_{vol}$ CO_2 (even more if pure oxygen is used instead of air) and the hydrogen and carbon dioxide are physically separated via pressure swing absorption (CAN Europe, 2003).

The combustion of hydrogen emits a relatively pure stream of water vapor. However, modern gas turbines accept hydrogen concentrations only up to 60% in order to limit the flame temperature at a level on which materials work reliable. Further research is needed to develop turbines which accept higher concentrations or pure hydrogen to increase the efficiency of the IGCC process. The combination of the gas turbine with a steam turbine further increases system efficiency.

Decoupling the carbon separation from the electricity production offers some advantages. First, the power plant can react to load changes more easily, as the gasification process is best carried out in a continuous process but a gas turbine offers a more flexible utilization of the power plant. Second, hydrogen can be used in other applications such as chemical industries or as a road fuel driving fuel cell powered electric cars.

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



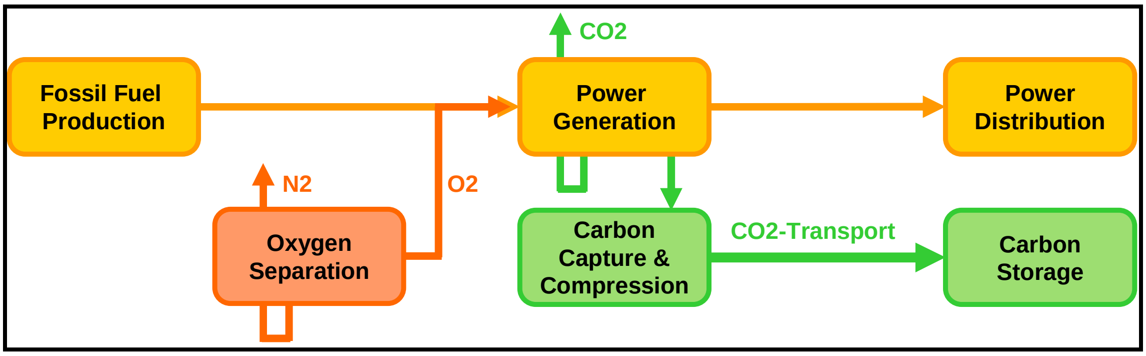
Source: Own depiction

2.1.3 Oxy-fuel technology

Another promising strategy to capture CO_2 is the combustion of fossil fuels in a pure oxygen and carbon dioxide atmosphere instead of ambient air. Shifting the CO_2 separation from the flue gas to the intake air results in a highly concentrated stream of CO_2 (up to 80%) after combustion. The remaining gas contains primarily H_2O. Part of the flue gas is recycled into the flame chamber in order to control the flame temperature at the level of a conventional power plant[1]. The water vapor is condensed and the pure CO_2 ($>99\%_{vol}$) stream compressed and transported to the storage site. The main cost driver of the oxy-fuel process is the energy intense separation of oxygen which alone might consume up to 15% of the plants electricity production (Vallentin, 2007; Herzog et al., 2004).

1 Flame temperature of pulverized coal in pure oxygen > 1400°C (Günther, 1999)

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



Source: Own depiction

2.1.4 Economic aspects of CO_2 capture

CCTS decreases plant efficiency and leads to a higher fuel consumption that causes additional emissions. These have to be considered when calculating CO_2 abatement costs in order to allow a comparison with other abatement strategies. Equation (1) shows the relationship between abatement and capture costs following IEA (2006b):

$$C_{aba} = C_{cap} * \frac{CE}{[eff_{new} / eff_{old} - (1\text{-}CE)]} \qquad (2\text{-}1)$$

Box 1: Legend

C_{aba}	abatement costs
C_{cap}	capture costs
eff_{new}	thermal efficiency of the CCTS plant
eff_{old}	thermal efficiency of the standard plant
CE	fraction of carbon captured

The multiplier for abatement cost c_{aba} relative to capture cost c_{cap} is lower for high efficiency plants. The efficiency losses for an IGCC plant with oxy-fuel capture are estimated to be in the 7% range in 2020 (46% efficiency without CCTS). Based on capture costs of 40 €/tCO_2, real abatement costs on account of the higher fuel consumption show as:

$$C_{aba} = 40€ / tCO_2 * \frac{0.85}{[0.39 / 0.46 - (1 - 0.85)]} = 40€ / tCO_2 * 1.22 \quad (2\text{-}2)$$

$$= 48.72€ / tCO_2$$

Due to the energy penalty and the higher capital expenditure of CCTS plants, the costs of electricity production will increase. Therefore, strong environmental and technology policy support is needed in order to start the required investments into demonstration and commercial plants.

Since coal is the fossil fuel emitting most CO_2 per unit of electricity produced, it is likely to be the first technology to benefit from CCTS. Cost estimates for CO_2 capture vary over a broad spectrum. Early estimations (IEA, 2001) typically exceeded more recent calculations. Further cost increase during the initial learning phase is possible and was widely observed along similar technologies such as catalytic NO_x reduction, flue gas desulphurization, combined cycle gas turbines, or LNG production. Table 1 and Table 2 summarize cost estimations for standard and CCTS plants for the year 2020.

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

Study		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)	RECCTS* (2007)
Pulverized Coal						
Efficiency	%	42,7	44	42	45,6	49
Investment	$€/kW_{el}$	1425	1086	1085	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	$€/kW_{el}$	1557	1335	1685	1100	1300
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

Source: RECCTS (2007, p. 153)

Table 2: Cost estimation for fossil plants with CO_2 capture in 2020

Study		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)	RECCTS[2)] (2007)
Pulverized Coal CCTS						
Efficiency	%	31	36	33.7	35.4	40
Investment	€/kW_{el}	2385	1823	1880	1470	1750
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
IGCC, Hard-Coal CCTS						
Efficiency	%	37	40	42,2	40,3	42
Investment	€/kW_{el}	2011	1733	2375	1720	2000
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}	1125	850	890	1170	900
O&M	€/kW,a	52.8	35	51.7		54
Capture Rate	%	85.1	86.1	86.6	94.1	85.9
Electricity costs with CO_2[1)3)] penalty	€ct_{2000}/kWh_{el}	7.12	5.77	5.99	6.59	6.16

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

Source: RECCTS (2007, p. 154)

To put these numbers in context, CO_2 from natural sources is estimated to cost around 75 US cent per Mcf or 1.3 US UScent/tCO_2 including pipeline transport and around 0.1 US cent/tCO_2 at the production well at Bravo Dome (Moritis, 2001).

CCTS components are expected to benefit from learning effects when market diffusion starts. Efficiency and capture rates will further improve, while capital costs decline. Consequently, lower costs as compared to CCTS plants having been built after the research and demonstration phase are expected for those realized in 2020 and later periods. Rubin (2004) estimates the learning rate for CO_2 scrubbers to 11-13% if the installed capacity doubles. Table 8 in the Appendix compares the resulting cost estimates for developed CCTS plants in 2020 and further matured plants in 2040. The resulting average CO_2 abatement costs including transportation and storage are estimated to decline within the next decades, but rise again if low cost storage capacity comes to its end eventually (Table 3).

Table 3: RECCTS estimation about future CO_2 abatement costs by means of CCTS

		Time of operation			
		2020	2030	2040	2050
PC	€$_{2000}$/tCO_2	42.6	41.15	39.6	40.1
IGCC	€$_{2000}$/tCO_2	42.6	37.35	36.75	37.25
NGCC	€$_{2000}$/tCO_2	60.95	54.9	48.85	51

Source: RECCTS (2007)

Besides fossil fuel fired power plants, other mid-scale sources such as cement manufacturing, ammonia production, iron and other metal smelters, industrial boilers, refineries, and natural gas wells are considered as potential CCTS applications. Those facilities produce CO_2 in less quantity (< 200 MtCO_2/yr in total), but nevertheless are qualified for the implementation of CCTS (IEA, 2004) due to the high CO_2 concentration in the flue gas. Higher concentrations of CO_2 allow for cheaper capture and those industries therefore can help to gain experience with the CCTS process chain at lower costs.

Table 4: Typical costs of CO_2 capture for industrial plants

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

Source: Ecofys (2004)

2.2 Transportation

Transportation of CO_2 can be conducted over a network of pipelines similar to those of natural gas or crude oil, by truck, train, or ship. The transport in solid state (dry-ice) is not an option, despite its low transport volume. The amount of energy required to cool down the CO_2 (375 kWh/t) is four times higher than for the transportation in liquid form (96 kWh/t) (RECCTS, 2007). On-road or rail transport is merely considered as an option in the up-scaling phase of CCTS with the required pipeline network still being under construction.

2.2.1 Pipeline transportation

Pipeline transportation is commonly understood as the only economic transport solution onshore which is capable to carry the quantities emitted by large scale sources such as power plants[2]. At the end of 2009, more than 5,000 km of CO_2 pipelines are operating worldwide, capable of

[2] A typical coal fired 1000 MW plant emits about 13 ktCO_2/d (Vallentin, 2007).

transporting 50 Mt/yr (RECCTS, 2007). Transport faces no significant technological barriers and is usually carried out in liquid or super-critical state in order to avoid two-phase flow regimes. Transport costs are mainly determined by the high upfront costs for building the pipeline network.

Dry (moisture-free) CO_2 is not corrosive to the carbon-manganese steels customarily used for pipelines, even if the CO_2 contains contaminants such as oxygen, hydrogen sulphide, and sulphur or nitrogen oxides. Moisture-laden CO_2, on the other hand, is highly corrosive, so a CO_2 pipeline in this case would have to be made from a corrosion-resistant alloy, or be internally clad with an alloy or a continuous polymer coating. Some pipelines are made from corrosion-resistant alloys, although the cost of materials is several times larger than carbon- manganese steels.

2.2.2 Over sea transportation

Shipping CO_2 will probably be limited to some niche applications in the beginning as there is an international consensus about not storing CO_2 in the ocean due to unpredictable consequences for the marine ecosystem. Yet, countries like Japan suffer from a lack of geological storage potential and therefore are forced to ship CO_2 to countries such as the Middle East or Russia where it can be stored in depleted or operational oil and natural gas fields. The dislocation of global CO_2 sources and economic sinks requires cost-effective inter-regional transport solutions. Shipping LNG to consumers and taking back CO_2 could result in a more economic overseas transport.

2.2.3 Economic aspects of pipeline CO_2 transport

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

Pipeline transportation is based on a pressure gradient induced by an initial compression of the commodity to nominal pressure (i.e., typically above 8 MPa for CO_2 in order to avoid two-phase flow regimes and to increase gas density). Pressure losses occurring during transport are adjusted by on-route compressor stations. In order to calculate the gas flow in pipelines, so called Weymouth formula are consulted. These equations exist in various modifications; Dahl (2002, p. 10) introduce a flow equation of the following form:

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

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

(2-4)

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

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

with the parameters as defined below.

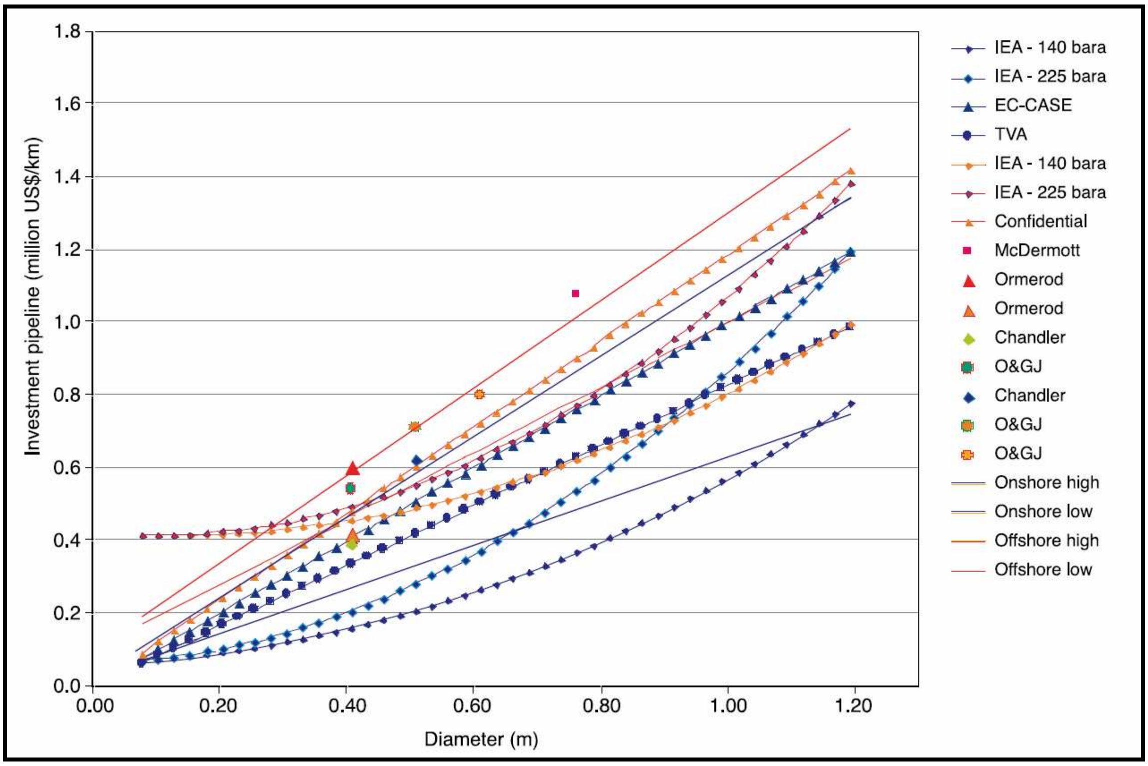
Box 2: Legend

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 [million m³ per day]
$Q_{cf/d}$	Flow under norm conditions [cubic feet per day]
T_{SC}	Temperature under norm conditions [288.15K]
P_{SC}	Pressure under norm conditions [1.01325 bar]
d	Pipeline diameter [m respectively inch]
L	Pipeline length [m respectively miles]
f	Friction coefficient
e	Pipeline roughness

Pipeline capacity, depending on inlet pressure, outlet pressure and a number of flow parameters, increases disproportionally to the diameter (i.e., with an exponent of 2.65). Thus, significant scale economies can be realized. Beside this volume effect, an increasing diameter also leads to a decrease in friction losses. However, proportional to the mass flow, the drop in pressure rises along a given distance and therefore, higher compressor capacities are required being reflected in an increase in the variable costs of pipeline operation.

CO_2 pipelines, representing a typical network industry, are characterized by very high upfront investment costs. These are sunk in nature and vary between 0.2 million (± 60%) and up to 1 million Euro (± 40%) per km for pipelines with a nominal diameter of 200 mm (1,200 mm), respectively (see Figure 4). The cost advantage for the construction of parallel pipelines accounts for 20% for the construction of a second line within the same track and 30% for the third line. Compressor stations add to the investment costs about 7 million Euros for onshore stations and 14 million Euros for offshore stations. Environmental conditions, such as onshore versus offshore siting, the necessity to deal with mountains or large rivers on the route, or frozen grounds, will have a substantial impact on transportation costs, too. In contrast, variable costs, primarily including expenditures for fueling compressor stations, are mainly determined by the transportation distance and are comparatively insignificant. In summary, CO_2 transportation costs vary between less than 1 Euro and more than 20 €/tCO_2 being a function of the transportation distance (i.e., 100 to 1,500 km) and the CO_2 mass flow.

Figure 4: Pipeline cost estimates



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

Source: IPCC, 2005

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

Economic policy generally aims at establishing the highest possible degree of competition in order to maximize social welfare (i.e., the sum of consumer rent and producer rent). Effective competition prevails if the static and dynamic functions of competition are realized to a large extent and if there is no permanent and relevant market power of certain players (see also Viscusi et al., 2005 or Motta, 2004). Effective competition can be realized 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). However, it is evident 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.[3]

Once a CO_2 pipeline is built, there will be an illiquid market for trading capacity ex-post. The pipeline owner will have to negotiate tariffs for shipping capacity with potential customers. The outcome of this negotiation will depend on the outside options of the parties. Thereby, a potential customer might build an own pipeline, build its CCTS plant on another site, or employ an alternative mode of transportation such as ships or trucks. The pipeline owner could employ the capacity for own uses or sell it to another customer. The value of these outside options will alter the respective bargaining power.

2.2.4 Point-to-point connections versus a meshed network

One important question regarding to the future CO_2 transport sector is the shape of the future network. The decision whether point-to-point connections or a network should be preferred is driven by the degree of dislocation of expected large scale sources and sinks and the related storage capacity. Dahowski et al. (2005) conclude that 77% of the total annual CO_2 captured from the major North American sources may be stored in reservoirs directly underlying these sources, and that an additional 18% may be stored within 100 miles of additional sources. In this case, point-to-point connections, built, owned and operated by the power plant operator, would be the most efficient mode of governance. This also implies that the storage capacity of the sinks is well known and large enough for CO_2 injection over the plant life.

However, if uncertainty enters into the equation, incentives to integrate vertically will change. A meshed network, connecting a larger number of storage sites and power plants, enables risk

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

mitigation both for the power plant and storage operators. We will draw on this point in detail in Chapter 3.6. In the case of regionally dispersed sources and sinks, and long transport distances, the benefits of a meshed, interconnected pipeline network increase. Such a system is also favorable from a system security perspective and cross border transport and storage of CO_2. The trade-off between point-to-point and meshed CO_2-transport will be an important issue for Europe. Transport over longer distances is likely to become important for the implementation of CCTS in some European countries. Especially the southern European states lack geological formations suitable for CO_2 storage on a larger scale. But also for countries like Germany, the Netherlands, or the UK, in which storage in the form of depleted natural gas fields or saline aquifers is available, backbone pipelines will offer an attractive alternative to onshore storage and the related "not in my backyard" (NIMBY) problem. In Germany, we observe a controversial public discussion; the legislation on transport and storage of CO_2 in Germany failed in 2009. Some states refused to store CO_2 as a consequence of massive public concerns on safety issues, but also due to concerns of decreasing land value. Therefore, storage of CO_2 in saline formations or depleted fossil fuel reservoirs below the North- or Baltic Sea might strongly increase acceptation, but also the costs of the CCTS technology.

2.3 Storage

Global storage potential for CO_2 is limited. Recent studies about its range vary in their outcomes. The IPCC (2005) estimates the global technical geologic storage potential to be at least in the range of 2000 $GtCO_2$, a number which, according to Dooley et al. (2004), can rise significantly if a larger share of saline formations proving to be stable is taken into account. Total capacity of depleted oil and gas fields is estimated to be 900 $GtCO_2$, which alone will hold enough storage potential for the next 50 years given today's global CO_2 emissions (IPCC, 2005).

2.3.1 Deep saline formations

Besides the storage in abandoned and active oil or gas fields which is applied today, deep saline fields and aquifers are considered as long term stable and secure. Saline formations are layers of porous rock that are filled with saline solution. They are much more common than coal seams or oil and gas reservoirs, representing a potential for CO_2 of up to 10,000 $GtCO_2$. However, it remains unclear which share can be economically used for storage.

Geologic formations which qualify for CO_2 storage have to come with layers of porous rock (usually sandstone or carbonates) or cavities deep underground that are sealed upwards by a layer or multiple layers of non-porous rock (e.g., granite). The injected CO_2 flows through the formation where it will spread out until it reaches the upper sealing. Saline formations tend to have a lower permeability than hydrocarbon-bearing formations. More wells are needed to achieve a sufficient dispersion of the injected CO_2. Besides the lower porosity, saline formations contain minerals that could react with injected CO_2 under formation of solid carbonates. If the carbonate reactions occur over a long time, those reactions may increase permanence. However, in cases the reaction happens fast and close to the injection well, it may plug up the formation (IPCC, 2004).

2.3.2 Fossil fuel reservoirs

Storage in depleted oil fields and gas reservoirs, including enhanced oil recovery (EOR) and enhanced gas recovery (EGR) is estimated a hold a potential of 1000-1800 $GtCO_2$ (Ecofys 2004). Those formations have proven their safety for millions of years and their geology is well known due to the exploration process.

Enhanced oil recovery is a common and mature technology increasing the economic benefit from oil production. More than 40 $MtCO_2$/yr currently are injected into oil fields mainly in Texas/US and Canada (IPCC, 2005). The pressurized CO_2 expands in the field and pushes oil to a production well. Furthermore, the CO_2 decreases viscosity of the oil which leads to a higher flow rate and can be pumped into the surface more easily (Melzer, 2007). The increase in total recovery can lead to additional monetary benefits of 50% for an average field (IEA, 2004). So far, most of the CO_2 is taken from natural sources in the western of the US (32 $MtCO_2$/yr) or from industrial production (11 $MtCO_2$/yr).

Similar to EOR, the CO_2 is injected into natural gas reservoirs. Due to higher density, it sinks to the ground and pushes the remaining natural gas upwards. Additionally it re-pressurizes the gas field which leads to a better depletion rate. EGR is still in the demonstration phase and a future large scale application is uncertain. Modeling done by Oldenburg et al. (2003) suggests that EGR might be economically feasible at CO_2 delivery costs of 4-12 US$/t compared to 25-55 US$/t in EOR operations (IEA, 2004).

Besides oil and gas fields, un-minable coal seams might be used for CO_2 storage. The enhanced coal-bed methane recovery (ECBM) aims on deep coal-beds which cannot be exploited at reasonable cost. In contrast to oil or gas fields, coal beds are widespread and more evenly distributed around the world. Especially China shows a major interest in this technology. The CO_2 is injected into the field and is absorbed on the coal surface, displacing coal bounded methane. The IPCC (2005) estimates the storage potential to be in the range of three to 200 $GtCO_2$. The IEA (2006b) estimates economic benefits to be 2-30 US$/$tCO_2$. But the productivity decreases with the amount of CO_2 stored underground as permeability reduces, making the process economically worthwhile in the beginning but less profitable after some time.

2.3.3 Ocean storage

Except Japan, which lacks of major depleted oil or gas fields, all countries involved in current CCTS projects reject direct ocean storage. Storage potential estimates differ widely between 1400 and $2x10^7$ GtC (IEA, 2001). The expected negative impact on the marine ph-value in case of large quantities of CO_2 dissolving in the ocean and the resulting consequences for the submarine ecosystem forms a massive global refusal against this storage solution.

Three techniques are considered to store carbon dioxide in the ocean. First, gaseous CO_2 can be injected into the sea and will dissolve in the water. This process takes place naturally on the surface and sequesters continuously about 2 GtC/yr from the atmosphere. Yet, warm surface water dissolves less CO_2 then cold layers at the ground, thus limiting the theoretical storage potential (IPCC, 2005). Second, the idea is to by pass this slow process by injecting CO_2 into depths greater than 3000m, where it stays in liquid form due to the high pressure of the surrounding water. The higher density of liquefied CO_2 compared to seawater will result in pools of CO_2 on the ground. The third form of ocean storage involves fertilization of sea regions which are low in nutrients with iron or urea. The increase in nutrient results in a higher production rate of phytoplankton. While 70% of the organic matter is recycled on the surface, the remaining 30% sinks to the ground and takes the carbon with it. Experiments, for instance in the tropical pacific, showed that a surface iron fertilization results in a temporary increase in phytoplankton (Coale et al., 1996). Boyd et al. (2000), however, show that this effect only holds temporarily and leads to oxygen shortage, the decomposition of the organic matter, and finally to an increase in greenhouse gases such as methane and NO_x while just about 1% of the organic bounded carbon sinks into the deeper ocean.

2.3.4 Monitoring

The storage of CO_2 in geologic formations requires a sufficient permanence and the complementing monitoring. The risk of leakage falls into two categories. The first one, on a global scale, involves the contribution of leaking CO_2 to climate change. The second category involves local risks for humans or the ecosystem close to the reservoir. The consequences for the ecosystem can include groundwater contamination and lethal effects on subsoil animals as well as on plants. However, it should be noted that given a storage depth of several hundred meters, abrupt leakage of large quantities seems rather unlikely.

The leakage rate of individual formations is unpredictable and can vary between no leakage and unforeseen high rates. Low leakage is acceptable, but has to be monitored over a long time horizon. Geologic formations can start leakage some 100 years after the last injection. This period exceeds the economic planning horizon of firms and makes governmental intervention necessary.

The average acceptable leakage rate can be estimated by taking future emissions and the maximum atmospheric CO_2 level into account. Zweigel and Lindeberg (2003) calculate the retention time to be 7000 years in a stabilization scenario with 450 ppm CO_2 and about 5.67 PtC remaining for combustion. If carbon intense electricity generation should become insignificant by the end of the 21st century, a retention time of 100 years would be sufficient. Referring to a storage time between 100-2000 years, the maximum leakage rate lies between 0.01 and 1% per year. Gas and oil fields have proven their sealing for millions of years and the geologic conditions are well known after depletion. For aquifers, that data is much harder to determine and is subject to a higher rate of uncertainty (IEA, 2004).

2.3.5 Economic aspects of CO_2 storage

Storage costs are separated into upfront and operation costs. Upfront costs, such as exploration, site assessment and drilling as well as seismic monitoring during the exploration phase. Storage operation costs include monitoring and injection costs which represent only about 20% of total storage costs. Storage costs increase with the depth below ground and further augment dramatically in case of off-shore fields (see Table 5).

Table 5: Cost estimates of CO_2 storage options in €/tCO_2

	Depth of Storage (m)		
	1000	2000	3000
Aquifer onshore	1,8	2,7	5,9
Aquifer offshore	4,5	7,3	11,4
Natural gas field onshore	1,1	1,6	3,6
Natural gas field offshore	3,6	5,7	7,7
Empty oil field onshore	1,1	1,6	3,6
Empty oil field offshore	3,6	5,7	7,7
	Low	Medium	High
EOR onshore	-10	0	10
EOR offshore	-10	3	20
ECBM	0	10	30

Source: Vallentin (2007, p. 37)

3 International Experiences: The Development of the US CO_2 Pipeline Network

3.1 Enhanced oil recovery: The predominant application

Conventional oil production yields only a fraction of the original oil in place (OOIP) of a specific oil field. When this method is exhausted and production rates are declining, water (secondary recovery) and CO_2 floods (tertiary recovery), among other measures, may be used to increase production.

Two techniques for CO_2 flooding can be differentiated, i.e., miscible and immiscible. In *miscible* CO_2 floods, CO_2 is pumped into the mature oil field above its minimum miscibility pressure (MMP) and acts as a solvent for the crude, improving its fluidity and increasing the pressure, thus pushing the oil to the well. Since oil flows through the reservoir with less ease than the gas, CO_2 may "brake through". Therefore water and CO_2 are usually injected in turns in a so called "water alternating gas" (WAG) process, as to create a barrier of water for both CO_2 and oil. In *immiscible* CO_2 floods, the CO_2 is pumped underground with lower than minimum miscibility pressure and pushes the oil towards the production wells. In both cases, a significant part of the CO_2 is transported back to the surface with the oil, but is usually captured and recycled.

3.2 Network development

As a reaction to the oil crisis, the US government strongly promoted enhanced fossil fuel recovery in the 1970s. This included a tax break. In 1991, the IRC§43 EOR tax credit became effective. It offered a tax credit for three general types of qualified costs - tangible property, intangible drilling and development costs (IDC), and tertiary injectants. In 2006, the 15% tax credit was phased out due to high oil prices (Jones, 2007).

The first project utilizing CO_2 miscible floods was the SACROC unit in the Permian Basin in Texas. From January 1972 on, it used CO_2 from four gas processing plants. The CO_2 was delivered via the Common Reef Carriers pipeline. As the supply from anthropogenic sources did not suffice, natural reservoirs of CO_2, namely McElmo Dome in Colorado and Bravo Dome in New Mexico, where tapped and their CO_2 transported to the Permian Basin via the Cortez (808 km) and Bravo (351 km) pipelines, respectively. Other mature oil fields were connected to these pipelines, too, creating a large cluster of CO_2 EOR operations in the Permian Basin. The main CO_2 sources for the Permian Basin today are the McElmo Dome and DOE Canyon (966 MMcfd), Bravo Dome (290 MMcfd) and Sheep Mountain (40 MMcfd) units in Colorado and New Mexico, and several natural gas processing plants to the south of the basin, connected via the Val Verde Pipeline (75 MMcfd), totaling at 1,371 MMcfd or 26.6 Mt/a, see Moritis (2008). CO_2 availability is the limiting factor to the expansion of EOR operations in the basin and several companies seek to increase it with new pipelines.

Natural occurring CO_2 resources are usually discovered while prospecting for natural gas. In order to produce the CO_2, wells need to be drilled and additional installations for compression, dehydration and cooling are needed to place the gas into 'marketable condition', i.e., to remove water and other impurities from the gas and to transform it into a supercritical (dense fluid) phase. The development of a natural CO_2 source thus does not differ much from that of a natural gas field. The cost structure of CO_2 production from natural sources is dominated by the capital expenditures for exploration and the production wells and relatively low operating cost. Operation costs include energy for the conditioning facilities and the compressors and cost for safety measures if the installations are in a populated area.

According to Kinder Morgan (2009, p. 6 and p. 71), $290m are spent in the development of Doe Canyon Deep Unit and the expansion of the McElmo Dome Unit and Cortez Pipeline, $90m of which for drilling and installations at Doe Canyon field (delivering 120 MMcfd). The total increase of CO_2 production capacity of the investments amounts to 300 MMcfd (about 5.8 Mt/a).

Other major CO_2 pipeline operations in North America include the Weyburn CO_2 Monitoring and Storage Project, which captures about 2.9 Mt of CO_2 per year form a coal gasification plant in North Dakota and transports it 330 km through the Souris Valley Pipeline to mature oil fields in Saskatchewan, Canada, the EOR operations feed by CO_2 from the Jackson Dome in Mississippi and projects in Wyoming and Oklahoma. US oil production from CO_2 EOR (both miscible and immiscible) amounts to approximately 250,000 bbl/d or 5% of US domestic production.

Figure 5: US CO_2 transmission network

Source: European Energy Forum, 2010

3.3 Database

Today, there exist 100 CO_2 miscible and five CO_2 immiscible floods in the US, seven CO_2 miscible floods in Canada, one CO_2 miscible flood in Brazil and eleven CO_2 immiscible floods in other countries worldwide (OGJ, 2008).

Of the 23 major CO_2 pipelines analyzed, 19 are located in the US or Canada, one in Norway, Brazil, Algeria and another in Turkey. Their total length amounts to 4700 km. Two pipelines are more than 500 km long (i.e., Cortez pipeline with 808 km and Sheep Mountain pipeline with 656 km), 14 are between 500 km and 100 km and five are less than 100 km long, the shortest being Delta pipeline with 50 km. Capacities vary from 21 Mt/a (Cortez pipeline) to 0.7 Mt/a (Snøhvit).

Snøhvit (Norway) and In Salah (Algeria) are the only project where CO_2 is sequestered, due to the tax on carbon dioxide content of natural gas. All the other projects use CO_2 in secondary or tertiary oil recovery. Four pipelines transport CO_2 from industrial sources – gas processing and synthetic fuel plants or a natural gas liquefaction facility. The other 15 are used for CO_2 from geological sources. However, only for a small number of projects sufficient data were found to get an impression of the general structure of the sector. For recent projects, more data on the CO_2 volumes, the origin and the players are available. This might be due to the increasing sensibility of the public when it comes to climate change issues and a growing interest in EOR operations respectively.

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

#	Name of the pPipeline	Start of operation	Country	CO_2 source	Length [km]	Location
1	Cortez Pipeline	1984	USA	geological	808	Denver City Hub, Texas
2	McElmo Creek Pipeline		USA	geological	64	McElmo Creek Unit, Utah
3	Bravo Pipeline	1984	USA	geological	351	Denver City Hub, Texas
4	Transpetco/Bravo Pipeline	1996	USA	geological	193	Postle Field, Oklahoma
5	Sheep Mountain (Northern)	1972	USA	geological	296	Denver City Hub, Texas; via Bravo Dome
6	Sheep Mountain (Southern)	1972	USA	geological	360	Denver City Hub, Texas
7	Central Basin Pipeline		USA		225	
8	Este Pipeline		USA	geological	192	Salt Creek Terminus
9	Slaughter Pipeline	1994	USA	geological	64	Slaughter field
10	West Texas Pipeline		USA	geological	204	Hobbs Field, Keystone Field, Two Freds field
11	Llano Lateral		USA	geological	85	Vauum Unit, Maljamar, C. Vac
12	Canyon Reef Carriers Pipeline	1972	USA	industrial	225	SARCO field
13	Val Verde Pipeline	1998	USA	industrial	132	SARCO field
14	North East Jackson Dome Pipeline	1985	USA	geological	295	Little Creek field
15	Free State Pipeline	2006	USA	geological	138	Eucutta, Soso, Martinville and Heidelberg field, Mississippi
16	Delta Pipeline	2008	USA	geological	50	Tinsley field
17	Delta Pipeline extension	2009	USA	geological	109	Delhi field
18	Green Pipeline	2010	USA	various	515	Hastings field, Texas
19	Weyburn/Souris Valley Pipeline	2000	USA/CAN	industrial	330	Weyburn field, Saskatchewan, Canada

Source: Various publicly available data

Table 7: Major CO_2 pipelines elsewhere in the world

#	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

Source: Various publicly available data

3.4 Players along the value chain

The sector is characterized by a small number of private investors. They typically operate the CO_2 sink and source and in many cases also the midstream pipeline. As CO_2 is mainly taken from low-cost natural and some industrial sources in the absence of a carbon mitigation policy, the disability to store more CO_2 e.g. given low oil prices simply implies to close the tap of the reservoir or to release CO_2 from industrial sources into the atmosphere. Thus, the pipeline and the CO_2 source should more be regarded as an extension of the crude oil exploration and production value added chain.

The participants of the CO_2 market face risks similar to those on the natural gas market. High capital expenditures and sunk costs incur during the development of CO_2 fields. The construction of pipelines demands continuous cash flows from CO_2 production and pipeline operation. Producers of natural CO_2 cannot readily sell their gas to a random buyer, as the number of oil fields connected by CO_2 pipelines is limited and the start-up of a CO_2 flood requires certain technical preparations. EOR operators on the other hand depend on a steady supply of CO_2 to hold their oil production levels.

All parties are tied to one another technically due to the physical structure of the pipeline network. This is less of a constraint for EOR operations in the Permian Basin in Texas, where the bulk of EOR operations is located, as the network of different CO_2 pipelines with different owners and operators may allow for a change of the source or sink of CO_2, as long as it can be fed into the pipeline servicing the oil field or CO_2 source itself. The operators of anthropogenic CO_2 sources do not depend on the marketing of CO_2, as it can be vented in the atmosphere (in the absence of legal restrictions and carbon taxes or permits) without affecting the main business of processing natural gas or producing synthetic fuels.

These risks have been addressed in the reviewed applications by two means. The first mean represents vertical integration. Most participants have an ownership interest and/or operate at least two of the three segments of the value chain. The companies own and/or operate the CO_2 source and the pipeline, or the pipeline and the oil field where the CO_2 is used or they are active on all three levels. The considered projects 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. Second, long-term take-or-pay contracts are common in this business. In all cases where contract or pricing information was accessible, the price of CO_2 is linked to an index of the oil price (e.g., West Texas Intermediate). Contracts last several years and obligate the seller to purchase a certain minimum quantity of CO_2 in a given period of time or to reimburse the seller for the difference (see also Resolute, 2006 and 2007). According to IPCC (2005, p. 262) the CO_2 price (in US$ per thousand cubic feet) equates to 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 six to ten Mcf of CO_2 are needed to produce one incremental barrel of oil, so the cost of CO_2 in EOR operation constitutes about 20 to 35 % of the sales revenue and is the most expensive part of operating a CO_2 flood.

3.5 Network regulation

Regulation of the CO_2 network in the US is still in its infancy. Due to the technical comparability to natural gas and oil pipelines, future regulatory regimes may address issues similar to the pipeline transport of fossil fuels.

Looking at today's EOR sector, we will only get limited insight into the future appearance of the sector. The existing network developed mainly on a regional scale initiated by the economic benefits of CO_2 in EOR. Until recently, it remains limited in scale and scope. There is only a limited number of projects with few players involved. Most of the transport takes place on the intrastate level, and provisions, access and regulation of the network traditionally has not been a big issue. If CCs becomes a widely applied technology the future structure of the sector will include a large number of power plants being controlled by a high number of players, a well developed pipeline network on the intra- and interstate level and a variety of storage site owners.

Due to similar concerns about the exhibition of market power given the natural monopolistic structure of pipeline networks, future regulation of the network might develop similar to the fossil fuel transport via pipelines. In the oil sector, regulation emerged as a consequence of mergers, price and access behavior in the late 19th century. Under the Hepburn Act in 1906, federal regulatory responsibility over interstate oil pipelines was given to the Interstate Commerce Commission (ICC). At this time, John D. Rockefeller's Standard Oil controlled 90% of oil refining and 80% of oil transportation markets in US (Reed, 2004). The ICC declared most of the interstate pipelines as common carriers, declared rates as "just and reasonable" and required the allocation of shipments on a nondiscriminatory basis (Herzog et al., 2007). In 1977, responsibility for oil pipelines was transferred to the US Federal Energy Regulatory Commission (FERC). FERC implemented a pricing index for an upper level oil pipeline transportation charges but is not responsible for the sitting of the pipelines but is responsible for the transportation rates and capacity allocation.

Regulation of the natural gas network in the US emerged to protect consumers from ordinary high prices due to shipment rates. FERC took over intrastate responsibility in 1977, too, while regulation on the state level remained under the control of the federal states. FERC was also given responsibility over network expansion, which in the case of natural gas also includes storage facilities.

Similar to the transport of hydrocarbons, one must distinguish between intra- and interstate transport of CO_2. In contrast to fossil fuels, only a small number of intrastate CO_2 pipelines exist. They fall under the regulatory regime of a federal regulator. The first pipeline which raised the question which regulatory agency would be in charge of CO_2 pipelines was the Cortez pipeline in 1978. The Cortez Pipeline Company however argued that the pipeline would not fall under jurisdiction of the FERC which is only responsible for the transport of natural gas understandable as hydrocarbons and not naturally occurring gases. Consequently, the regulation of CO_2 pipelines did not fall under FERC jurisdiction.

As the Cortez Company seek a similar ruling from the ICC in 1980, ICC noted that it was not in charge of regulating any type of gases. Thus, there remains a regulatory gap as the Surface Transportation board also disclaimed responsibility over interstate CO_2 transport. This regulatory gap for a future CCTS pipeline network in the US must not in any case result in the abuse of market power by vertically integrated firms or pipeline operators. Those issues also fall under jurisdiction of the Federal Trade Commission or the antitrust division of the US Department of Justice.

To sum up, the regulatory framework for CO_2 transport and storage in the US is highly fragmented across the permitting process at different stages of value chain. Yet, the history of natural gas and oil pipeline transportation indicate the need for a well defined regulatory authority in order to provide investment incentives for an expansion of a CO_2 pipeline network in the US or the EU. Grossmann (2008) identified the lack of a harmonized legal framework, in particular for the transport and storage of CO_2 as the key barrier towards the large scale demonstration of CCTS.

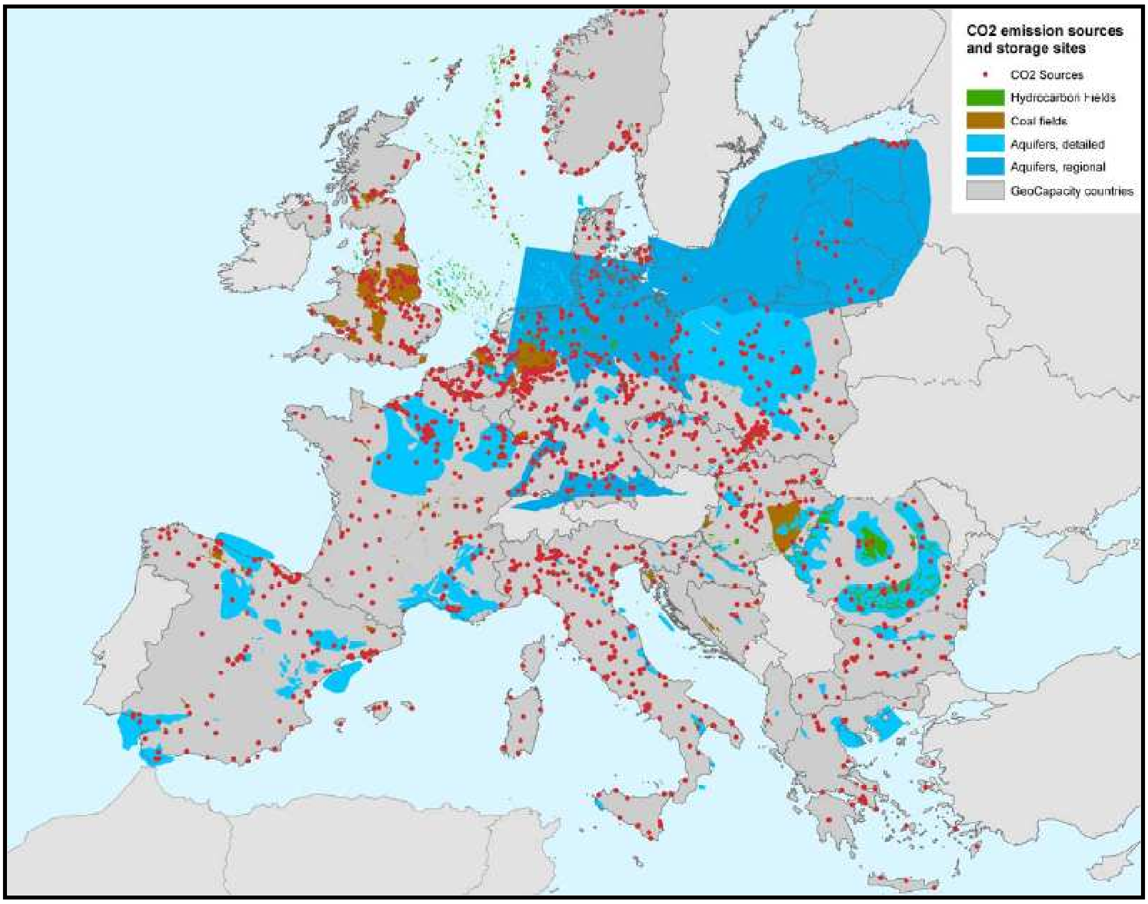
3.6 Implications for a European CO_2 network

When looking at the US sector, one might get the impression that pipeline transportation of CO_2 does not face any major barrier and that the development of the network could be left to market forces. This does not hold true for the future European CO_2 pipeline network which will differ substantially from the sector structure as we observe it in the US. First, the positive experience with CO_2-pipelines development was based upon a different business model (enhanced oil recovery, EOR), without either the objective of large-scale carbon capture nor long-term storage of most of the carbon. The 40 million tones transported and stored[4] in the US are not even close

[4] Under normal conditions, only about 30% of the injected CO_2 remains underground. The rest is brought up with the oil, from which it is separated and injected again.

to what is expected if CCTS becomes a mature and widely applied technology for CO_2 mitigation. Those volumes equal roughly to 10% of today's emission from the German electricity sector. Yet, it must be kept in mind that the many variables, such as carbon prices or availability of alternative technologies, influence the adoption of CCTS. But the allocation of possible large scale CO_2 sources and hence potential CCTS operators and for CO_2 storage suitable location will require a well designed network, including some large backbone pipelines (Figure 6).

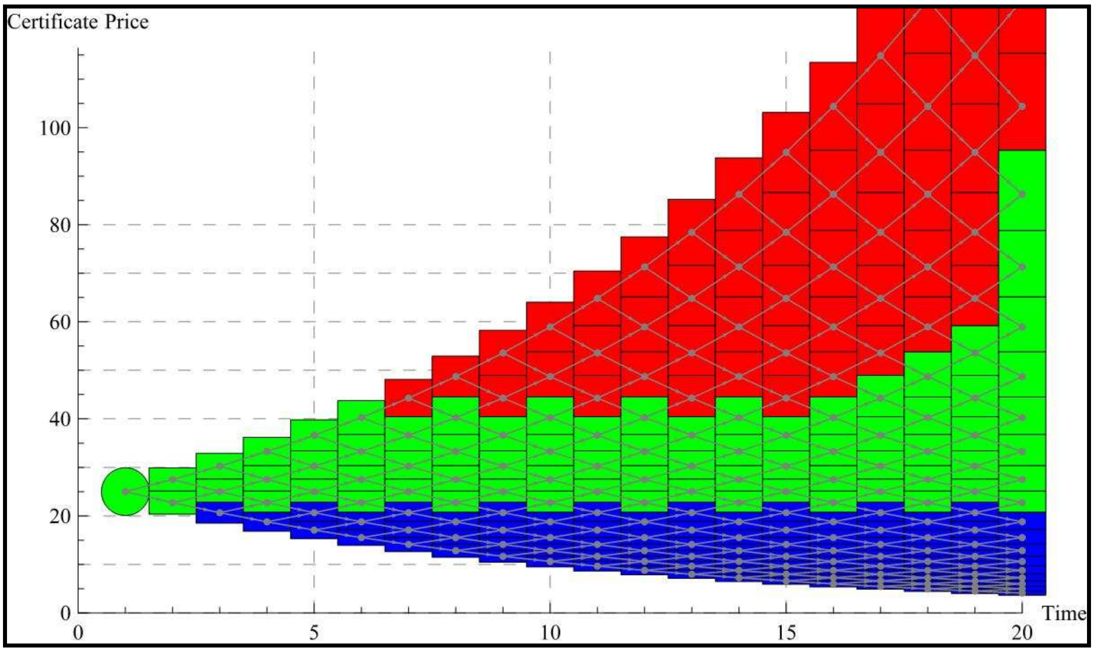
Figure 6: Estimated CO_2 sinks and sources in Europe



Source: EU GeoCapacity (2009)

Second, players along the value chain might have different incentives regarding capture, transport and storage as they face risks different from the US sector. The US sector is characterized by natural occurring CO_2 sources and some industrial applications. CO_2 can be produced at costs much lower compared to the capture in fossil power plants (starting at 0.1 UScent/tCO_2). CO_2 production in a carbon constrained world is driven by economic incentives set by carbon taxes, permits or emission standards. This does not necessarily imply a constant use of the capture unit in power plants. Geske and Herold (2010) analyze the investment and management decision for a retrofitable post combustion unit. They show that it might be profitable for a post-combustion capture plant to switch off the capture unit in case of low carbon prices. Assuming a thermal efficiency of 33% and a capture rate of 80 %, turning of the capture unit is the most economic way if prices drop below 20€/tCO_2 (lower area in Figure 7, the middle area indicates usage, while the upper area indicates a profitable investment opportunity).

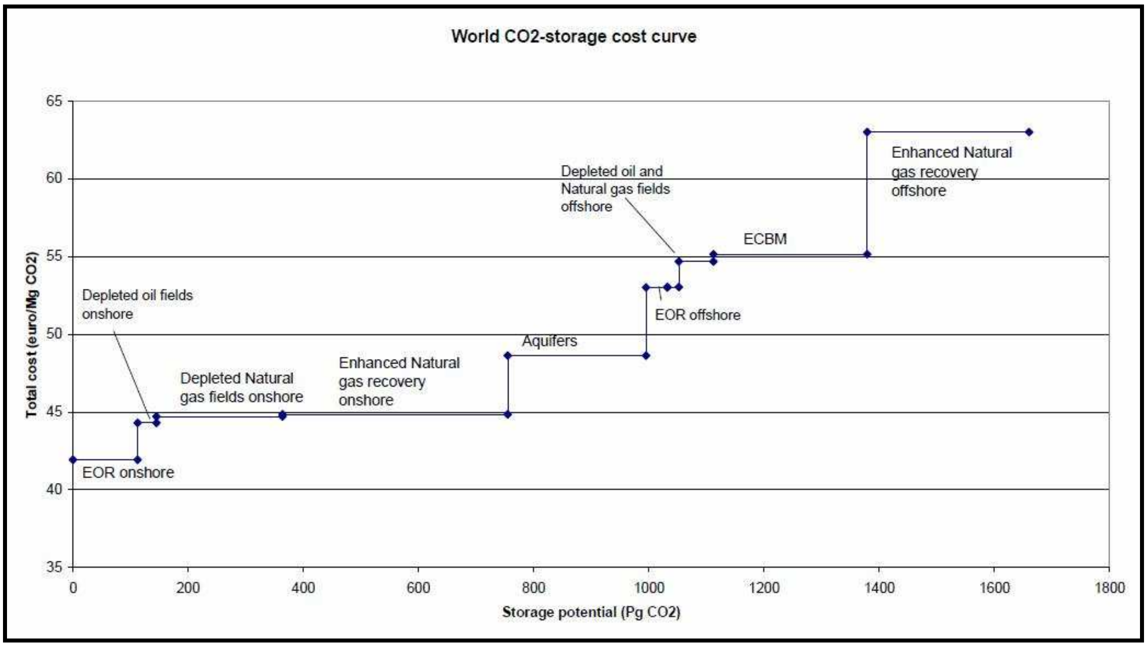
Figure 7: Investment and management decisions for a post-combustion capture unit



Source: Geske and Herold (2010)

Storage operators on the other hand, might have an incentive to inject less than the maximum rate into the field or to renegotiate the storage fee after the pipeline is built. As low costs storage sites, such as depleted oil or gas fields are scare in most of the European countries, average storage costs are expected to raise with the quantity of CO_2 injected and more expensive reservoirs being used (Figure 8). So it is the storage site operators who are in the strongest position when it comes to negotiations between players along the CCTS value added chain. This holds particularly true in if the storage operator is not the pipeline owner as in this case he would bear the high up-front investment costs for the pipeline, relying on a steady stream of CO_2.

Figure 8: World cost curve for CO_2 storage.



Costs are calculated by: (1) average capture and compression costs of 38.5 €/tCO2, (2) weighted world average of transport distance per type of reservoir and (3) typical storage costs per type of reservoir.

Soure: Ecofys (2004)

4 Vertical Structures along the CCTS Value Added Chain

In order to investigate vertical structures along the CCTS value added chain, the following discussion draws on both institutional economics and argumentations coming from the field of industrial organization. After the presentation of a number of selected case studies, the chapter concludes with a critical discussion of observed vertical structures and recommendations on how to support CCTS infrastructure investments in Europe.

4.1 Theoretical background

4.1.1 Motivations to integrate vertically drawn from Institutional Economics

New Institutional Economics (NIE) started to develop during the early 1970s and 1980s. One central research interest lies in organizational structures along value chains of production. The firm is understood as an institution reducing exchange risks as well as ex-post transaction costs. Competing theoretical frameworks within the field of NIE – despite their differing underlying assumptions – are based on a common starting point: In the absence of any transaction costs, contractual choices, organizations, and institutions are of no interest. The way property rights are distributed in an economy does not impact the way this economy uses scarce resources. These approaches explicitly allow for non-zero transaction costs (e.g., information costs, negotiating contracts, ex-post maladaptation and monitoring, etc.).

Transaction cost economics (founded on Williamson, 1975, 1985) hypothesizes that the optimal choice of governance depends on the relative costs of alternative institutional arrangements which in turn depend on the characteristics of the transaction at stake. Economic actors are assumed to be characterized by bounded rationality and may behave opportunistically. In a world in which uncertainty about the future state of nature is present, contracts will remain inevitably incomplete. As long as there is functioning competition among trading partners, incomplete contracts are unproblematic since outside options discipline market players. However, ex-post bilateral dependencies – as do result from investments in relationship specific assets such as pipeline infrastructures – will generate exchange hazards (e.g., opportunistic renegotiations). Asset specificity thereby refers to “durable investments that are undertaken in support of particular transactions, the opportunity cost […] is much lower in best alternative uses or by alternative users should the original transaction be prematurely terminated” (Williamson, 1985, p. 55).[5]

[5] Six types of relationship-specific assets are distinguished: i) site specificity (assets placed in close proximity in order to minimize transportation or time costs or to benefit from complementary advantages), ii) physical asset specificity (assets’ value in alternative uses is much lower), iii) dedicated

Given that long-term contracts are unavoidably incomplete and that contracts as mere promise are not self-enforcing, the question is which transactions should be organized under which governance modes. Anonymous spot markets have advantage over central planning in situations where the price reflects all relevant information. Firms get to specialize in doing what they do best; innovation is generated by numerous sources. Internal organization of successive stages of the value chain is the optimal governance choice where relationship-specific investments under uncertainty are required. Between the two poles a large variety of hybrid forms of governance (e.g., long-term contracts, joint ventures, or partial ownership arrangements) are settled.

The property rights theory (see e.g., Grossman and Hart, 1986; Hart and Moore, 1990) assumes perfect rationality of economic actors but ex-post non-verifiability of contractual provisions due to information asymmetry with third parties, which results in ex-ante investment distortions. It also builds on a framework of incomplete long-term contracts. Contractible specific rights are distinguished from non-contractible residual rights of control. A firm is limited by the assets over which it has control. The central proposition of the property rights approach argues that it is optimal to allow one party to purchase the asset when it is too costly to list all specific rights in a contract and that the party which is mainly responsible for the return of the asset should own it in order to be endued with the residual control rights.

On the roots of incentive theory a third stream of literature discussing vertical organizational structures has established (see e.g., Laffont and Martimort, 2002). Within this approach, the firm itself is not the unit of analysis, but rather the collection of contracts between owners and managers, managers and employees, and the firm and its customers and suppliers. The firm is understood as a nexus of contracts. The central question is the optimal design of ex-ante incentive compatible contracts suited to mitigate agency costs in the face of potential adverse selection and moral hazard. Firm boundary thereby is not the focal subject of attention.

4.1.2 Motivations to integrate vertically drawn from Industrial Organization

Under perfect competition the price reflects all relevant information. Several approaches originating from the field of Industrial Organization conclude that market imperfections such as the existence of market power, barriers to entry, price discrimination, or asymmetric information are possible drivers for vertical integration.

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assets (investments in assets dedicated to a certain trading partner that otherwise would not be made), iv) human asset specificity (human capital evolving due to learning of individuals), v) intangible assets (for example brands), and vi) temporal specificity (time factor is of large importance).

Vertical integration might be used to achieve anticompetitive effects such as the creation of barriers to entry and the strengthening of own market power by rising rivals costs or exacerbating market entry. However, vertical integration may not only create market power by gaining control over successive stages of a value chain, but can also be a response to market power of potential trading partners. Vertical integration can be mean avoiding successive monopolies and efficiency losses resulting from double marginalization.

Firms may integrate backwards to secure supply in situations characterized by high uncertainty and market failures, hence prices not reflecting all relevant information.

Another motivation to integrate is a potential free-rider problem**.** For example if a retailer invests in retailing services, but downstream competitors will also benefit from this investment, downward investment distortions will lead to under-investment. Forward integration avoids this free-rider problem and supports efficient investment levels.

An alternative justification is the technological interdependency argument. Between successive production processes there may be certain interdependency in time and place. Integrating processes, inputs can be optimized and total efficiency will be increased. An often cited example is the combined production of iron and steel, where thermal efficiencies play an important role. Economies of scale and scope lead to cost savings and probably also to gains in quality.

According to the life cycle theory of vertical integration based on Adam Smith's theorem arguing that the division of labor was limited by the extent of the market, emerging industries are characterized by a small size. During these early stages, the market will be insufficient for independent firms supplying input, technologies or specialized skills and vertical integration is expected to be the dominant organizational form. With the expansion of the industry, tasks can be turned over to specialists. When the industry ages and output quantity declines, it may happen that the surviving firm has to re-appropriate functions.

4.2 Vertical integration or des-integration?

Until today, most CCTS projects under operation or with a high probability of successful development concentrate on CO_2 as a valuable commodity, originating from geological or industrial sources and being employed in enhanced hydrocarbon production (i.e., EOR, EGR, ECBM). We commonly observe vertical integration into midstream transportation and long-term take-or-pay contracts. The following paragraphs present selected case studies and provide a critical discussion on vertical (des-)integration of midstream transportation.

4.2.1 Lessons from case studies

The following section introduces a number of selected case studies where the CCTS technology is employed. These include commercial projects of EOR as well as pilot projects aiming to mitigate CO_2 emissions from fossil-fuel combustion building on CO_2 sequestration.

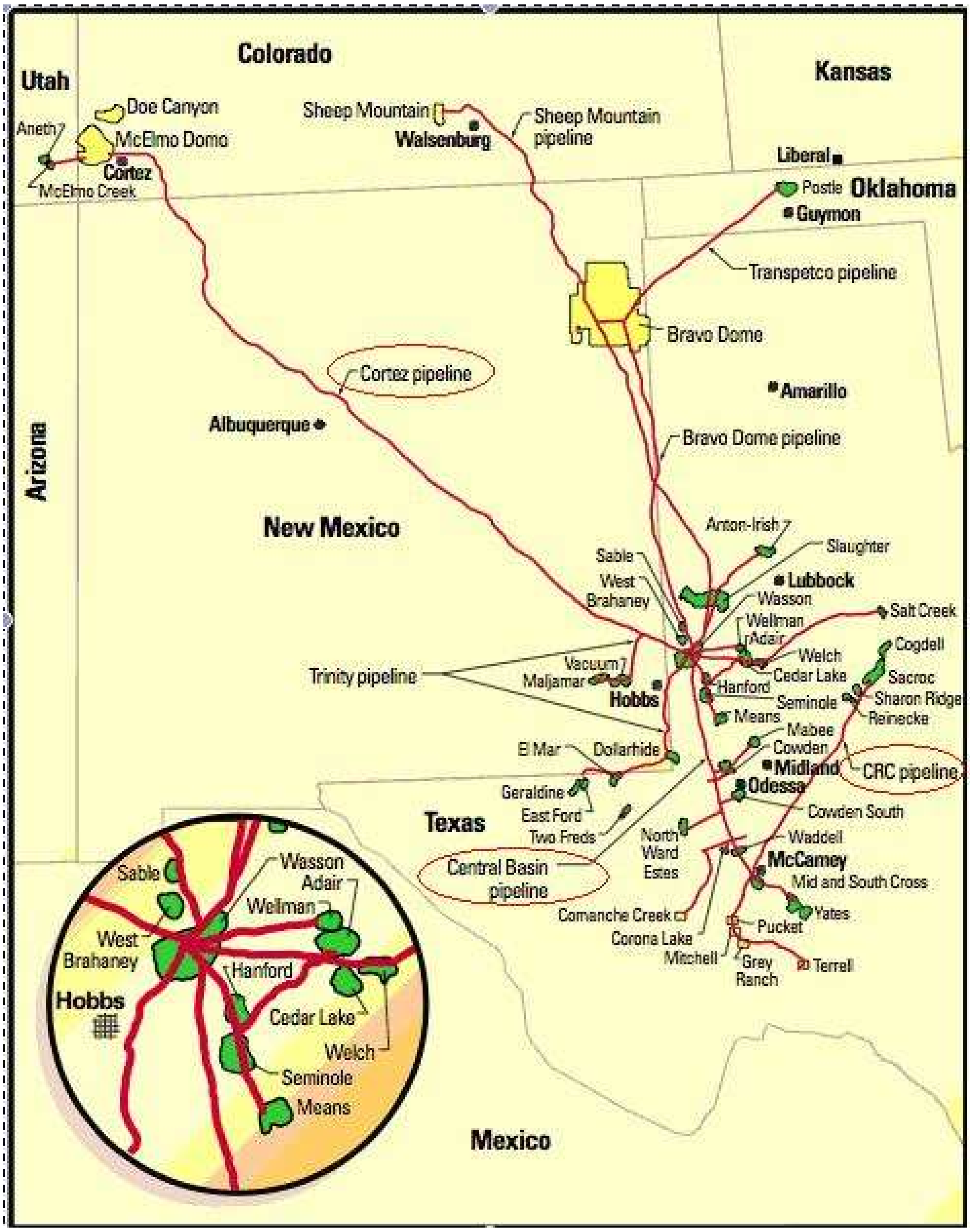
Kinder Morgan

“Kinder Morgan (KM) is a major pipeline transportation and energy storage company in North America with more than 37,000 miles of pipelines and 170 terminals. It transports, stores and handles energy products like natural gas, refined petroleum products, crude oil, ethanol, coal and carbon dioxide (CO_2). Kinder Morgan is the leading transporter and marketer of carbon dioxide in North America, delivering approximately 1.3 billion cubic feet per day of CO_2 through about 1,300 miles of pipelines” (Kinder Morgan, 2010).

With the Bravo and the McElmo Domes, Kinder Morgan owns the two biggest natural CO_2 fields used in the US. The McElmo Dome, which is primarily owned by KM and ExxonMobil, produces up to 50 Mmcfd out of 61 production wells. The Bravo Dome with its more than 10 tcf of CO_2 is connected via the Cortez pipeline (1 bcfd to 4 bcfd) with the Denver City Hub. From here, more than 40 smaller pipelines distribute the CO_2 to different oil fields (i.e. EOR operations). Those smaller pipelines are often partly or entirely owned by KM, which also acts as the pipeline operator. So KM acts as the CO_2 source, the pipeline supplier and operator, and is often also responsible for CO_2 injection. KM further offers their customers risk sharing instruments, such as financing, royalty interests, or other mutually agreed upon arrangements (Kinder Morgan, 2010).

According to the US Department of Energy, additional 210 billion barrel could be produced domestically with enhanced oil recovery (DOE, 2006). Due to increasing demand, both the McElmo Dome and its pipelines have recently been expanded. Still, the main barrier towards a stronger growth of enhanced oil recovery operations remains the limited availability of low cost CO_2. So in contrast to the European market, in which storage capacity is scarce and only limited incentives for the network construction are found, the availability of CO_2 for storage (i.e. employment as a valuable commodity) is the scarce resource companies strive for.

Figure 9: US CO_2 pipelines for oil and gas reservoir sequestration used by Kinder-Morgan



Source: Moritis, 2001

The ownership of the CO_2 transport network might provide Kinder Morgan with a strong position when it comes to negations on the CO_2 prices. However, CO_2 can only be used in EOR operations at low costs. Further, enhanced fossil fuel production can also be undertaken to some extent with water, while the substitution by nitrogen is also possible, depending on the resources available and the extent of depletion of the field. Yet, the pipeline operator is strongly dependent on a steady flow of CO_2, as the costs for the network are the biggest part of the CO_2 delivery price. Therefore, KM's options to exhibit market power are limited. On the other hand, the company faces some risk of opportunistic behavior by its customers. Therefore, vertical integration into the backbone and distribution networks and (to some extend also injection services) as well as the conclusion of long-term CO_2 delivery contracts are means to hedge the 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 (NEJD) pipelines. In both cases, long-term contracts for a period of 20 years are struck. The contract demands a fix payment of 150,000 US$ per month for the CO_2 from the Val Verde pipeline and 100,000 US$ for the Jackson Dome pipeline, respectively. Additionally, a tariff based on throughput and two renewal options for five years each on similar terms are agreed upon. Genesis purchased Denbury's Free State Pipeline for $75 million and entered into a twenty-year transportation services agreement to deliver CO_2 on that pipeline for Denbury's use in its EOR operations. Under the terms of the transportation services agreement, Denbury has exclusive use of the pipeline and is required to use the pipeline to supply CO_2 to its tertiary operations in that region. Genesis further entered into a twenty-year financing lease transaction valued at $175 million wherein Genesis acquired certain security interests in Denbury's North East Jackson NEJD Pipeline System Denbury has exclusive use of the NEJD pipeline system and will be responsible for all operations and maintenance on the system (Reuters, 2010).

Our sector analysis indicates a high level of vertical integration, as found often in sectors which require capital intensive investment with a high risk of costs being sunk in the future. However, in opposition to natural gas supply, an interruption of the CO_2 stream is less harmful to the business of an oil producer or CO_2 supplier. It takes about one to two years until oil production increases after CO_2 injection starts. Similarly, oil production won't stop in cases in which the CO_2 supply is interrupted due to technical or other reasons. In the Texas area we find a well developed network, mainly owned by Kinder Morgan. This company offers to manage the whole up-stream part of the CO_2 value added chain including the injection into the field.
For the supplier of CO_2, a lower demand means to throttle production if it relies on a natural source or to release it into the atmosphere. The costs, both for production as well as for injecting it into oil fields are rather minor, compared to the pipeline. Commonly used backbone pipelines, such as the Central Basin Pipeline (Figure 9) can help to keep the overall system costs low and to share the risk among a larger number of players.

EOR in the Weyburn oil field (Canada)

An illustrative example of the successful employment of EOR is the Weyburn oil field, operated by EnCana, Canada's largest oil company. It is located in the Saskatchewan province near the US border. Oil production started as early as 1955. In order to increase production, the injection of CO_2 began in 2000. The gas comes from the Great Plains Synfuels Plant in North Dakota, US, operated by the Dakota Gasification Company. This facility produces methane from coal since 1984. Thereby, synthetic natural gas is separated from other compounds, which consist to a large part of CO_2. The gas is transported as a supercritical fluid (i.e., with a pressure of about 152 bars) via pipeline to the oil field and pumped into 37 injection wells. The 330 km Souris Valley Pipeline, a subsidiary of the Dakota Gasification Company, transports about 4.3 million cubic meters of CO_2 per day to its Canadian customers.

This case study represents a classical win-win-win-situation. First, Dakota Gasification Company has found a customer for its waste-product CO_2, which since 2000 represents a commodity with an economic value instead of being vented into the atmosphere. Second, EnCana benefits from higher revenues from oil production. Furthermore, US CO_2 emissions are decreased, improving the country's climate balance.

We do observe vertical integration into midstream transportation of the upstream Dakota Gasification Company. From an institutional perspective, the choice of this organizational structure is a natural reaction to the presence of a highly relationship-specific investment. The construction of the pipeline exhibits high physical asset specificity; once in place, its salvage value approaches to zero and the investor faces the risk of being held-up by the non-investing party ex-post (e.g., renegotiation of shipping tariffs). Even though we have no information on the details of the contractual agreement between CO_2 supplier and customer, it is very likely that the exchange relationship is governed by a long-term contract including various adaptation clauses (i.e., price and quantity adjustments, force majeur) allocating the different risks to the suited party.

Schwarze Pumpe (Germany)

The Swedish energy company Vattenfall operates a 30 MW carbon capture pilot facility in the industrial area 'Schwarze Pumpe' (Germany) employing an oxyfuel process based on lignite combustion. After two years of construction, the 70 million Euro project started operation in 2008. It does not deliver any electricity to the distribution network, but rather sells produced steam to a neighboring paper mill. Operating at full capacity, the plant captures about nine metric tons of CO_2 per hour. Until today, no storage options are available. A part of the CO_2 is liquefied and transported by truck to industrial customers. Another part of the gas is vented into the atmosphere. Hence, Schwarze Pumpe has to be valuated as a pure pilot project focusing on the development and improvement of technological processes related to the oxyfuel process. According to Vattenfall, CO_2 from the facility as well as from later commercial CCTS applications could be transported to saline aquifer storage sites, which are available within the region. However, in order to support these infrastructure investments, a stable regulatory framework with respect to downstream transportation and storage is asked for.

Lacq (France)

A similar pilot project employing the oxyfuel technology – here with an upstream natural gas boiler – is currently under development in Lacq (France). The 60 million Euro project with a capacity of 30 MW_{th} is part of an integrated CCTS value chain completely operated by Total. About 75,000 metric tones of CO_2 are planned to be captured each year. The gas will be transported via a 27 km pipeline to a depleted gas field at Rousse, which once has been Europe’s biggest onshore natural gas field but has reached maturity. Total thereby takes advantage of the already existing pipeline which has been used during the past three decades to export natural gas produced from the Rousse field to a treatment facility at Lacq. Hence, the CO_2 will simply be shipped in the opposite direction than natural gas once has been.

This case study shows the successful realization of a complete CCTS value chain including carbon capture, transportation, and storage. However, the availability of pre-existing pipeline infrastructure is very likely to have been one major precondition for this project, since large-scale sunk costs thus not have been necessary and the operator is not exposed to a substantial regulatory risk concerning the transportation segment. Total represents a vertically integrated operator. In part this reflects the historical ownership situation of the assets. A former intra-company natural gas producing field and an affiliated gas processing facility simply have been transformed into a carbon capture pilot plant and a CO_2 sink. This enables Total to acquire technological knowledge without having to invest vast amounts of capital into an industry which still is in its infancy. Obviously, the organization of the whole project within the own corporation avoids costly negotiations with third parties and mitigates the risk of ex-post hold-up.

Brindisi (Italy)

The Italian power company Enel currently is developing a CCTS demonstration project including the retrofit of a 660 MW_{el} power plant located in Brindisi (Italy) which is fired by bituminous coal with a post-combustion capture facility. Up to 1.5 million tons of CO_2 per year are planned to be removed from the flue gas. In October 2008, the company signed a cooperation agreement with the Italian oil and gas major ENI to develop the value chain together and to jointly evaluate Italy's CO_2 storage potential. ENI contributes to the partnership CO_2 storage capacity in the depleted natural gas field of Cortemaggiore (900 km from Brindisi, near Piacenza, capacity of 8,000 tones per year); the first injection of CO_2 is scheduled for the end of 2010. During the pilot face of the carbon capture facility's operation, the CO_2 will be liquefied and transported to Cortemaggiore by truck (~230 trucks per year). However, ENI currently is exploring the potential to use existing natural gas pipelines for the transportation of CO_2. Potential further storage sites in the regions of the Adriatic and Ionian Seas are under evaluation.

This case study clearly mirrors the infrastructure investment dilemma concerning a network of CO_2 pipelines. The cooperating parties avoid binding themselves with this highly capital incentive and at the same time sunk investment. Even though the distance from CO_2 source to sink with about 900 km is substantial and major CO_2 volumes are expected to be captured from this 660 MW_{el} power plant. Instead, they chose to employ trucks for the transportation during the first phase of the project; in the longer-term, existing natural gas transportation infrastructure is planned to be rededicated in favor of CO_2, avoiding again large-scale investments in an uncertain regulatory framework.

Another interesting issue is that this case shows the successful cooperation of players with varying core competences. A traditional electricity company contributes knowledge on power production and carbon capture, whereas a traditional oil and natural gas producer contributes knowledge on geological storage and piping.

4.2.2 Critical discussion

As discussed in Chapter 2, pipeline transportation of CO_2 represents a natural monopoly; it is characterized by very high upfront investments that are sunk in nature and the potential to realize substantial economies of scale. Whereas the carbon transport sector (CTS) sector in the US concentrates on CO_2 as a valuable commodity used to increase the production of hydrocarbons, European efforts focus on CCTS as a mean to mitigate greenhouse gas emissions. The reasons of initiating technological innovations and infrastructure investments differ substantially between the two regions. Therefore, US experiences with the provision of investment incentives only can be alienated to the European situation to some extents. Rather, region-specific conditions have to be taken into account.

5 Summary and Conclusions

The future of CCTS in Europe strongly depends on the implementation of an adequate and stable regulatory framework accounting for industry-specific challenges. Infrastructure investments in carbon capture and transportation infrastructure as well as CO_2 deposits are highly capital-intensive. Large-scale regional and international transportation is likely to rely on pipeline networks. Due to the lack of an inherent value of CO_2 the revenue stream strongly depends on future regulatory decisions. Furthermore, technological uncertainties relate especially to storages, but also to carbon capture technologies which still are in the demonstration phase. The uncertainty surrounding future projects should be reduced. European CO_2 prices, although being the worlds highest, have failed to set proper investment incentives for the CCTS technology. In the absence of clear CO_2 price corridors and signals, regulatory certainty can be created, e.g., by obliging new power plants in include a “capture-ready” option.

As learned from the US EOR sector, optimal conditions for a technology’s validation exist when strategic interests of government and businesses come together. There are comparable cases given by other energy technologies such as nuclear power or LNG, both having been characterized by highly capital incentive infrastructure investments and uncertainties (e.g. technological, regulatory), too. As a reaction to the oil crisis, many governments have been willing to take over the risks associated with nuclear energy production. For LNG, security of supply concerns and high oil prices convinced Japan to take over almost all the risk associated with the first LNG projects (Rai et al., 2009).

Given the high capital intensity of both, the capture technology as well as the CO_2 transport network, and the high level of uncertainties for the first demonstration plants, governments should reconsider their contribution to the development of the necessary infrastructure. First experiences with pilot CCTS projects in both the US and Europe have shown that in the absence of an investment environment exhibiting benefits for all stakeholders, the presence of relationship-specific assets and regulatory uncertainties inhibit infrastructure investments.

Even though considerable asset-specific investments are required along the value-added chain of CCTS, vertical integration into long distance transmission and regional distribution networks, i.e. unified ownership, is not necessarily the first-best option. Whereas CO_2 capture should be left to industry, the state bares a crucial role in the development of the transportation and storage infrastructure. CO_2-transportation infrastructure should be sited and the necessary planning steps be carried out. The execution of the construction and operation can be tendered to the private sector, or carried out by a state-owned network company. Synergies with the other energy network infrastructure (mainly natural gas) should be sought.

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Appendix

Table 8: Cost estimation for fossil plants with CO_2 capture in 2040

		Pulverized Coal[1]		IGCC		NGCC	
		2020	2040	2020	2040	2020	2040
Without Capture							
Efficiency	%	49	50	50	54	60	62
Investment	€/kW_{el}	950	900	1300	1200	400	400
CO_2 emissions	g/kWh_{el}	673	635	660	611	337	326
Electricity costs without CO_2[1)3)] penalty	€ct_{2000}/kWh_{el}	3.87	3.60	4.46	4.12	4.44	4.32
With Capture							
Efficiency	%	40	44	42	46	51	55
Investment	€/kW_{el}	1750	1600	2000	1800	900	750
Capture Rate	%	85.3	88.2	85.7	90.6	85.9	91.0
Additional fuel consumption	%	22.5	18.2	19.0	17.4	17.6	12.7
Electricity costs with CO_2[1)3)] penalty	€ct_{2000}/kWh_{el}	5.95	5.43	6.28	5.74	6.08	5.50

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

Source: RECCTS (2007, p. 156)

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sources, Part 1

				CO2 Feedstock						
#	Project Name	Start-up	Country	Location	Type	Owners	(%)	Operator	Contracting Structure	Reserves [Nm³]
1	**Cortez Pipeline**	1984	USA	McElmo Dome, Colorado	geological	Kinder Morgan, ExxonMobil, Chevron, multiple private	45 44 4 8	Kinder Morgan		4,028E+11
2	**McElmo Creek Pipeline**		USA	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	USA	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	USA	Bravo Dome, New Mexico	geological	Oxy, Kinder Morgan, Amerada Hess, multiple private	75 11 10 4			8,056E+10
5a	**Sheep Mountain (northern)**		USA	Sheep Mountain, Colorado	geological	BP, ExxonMobil	50 50	Oxy		1,343E+10
5b	**Sheep Mountain (southern)**		USA	Sheep Mountain, Colorado Bravo Dome, New Mexico	geological 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**		USA	no single source						
7	**Este Pipeline**		USA	Denver City Hub	geological					
8	**Slaughter P.**		USA	Denver City Hub	geological					
9	**West Texas P.**		USA	Denver City Hub	geological					
10	**Llano Lateral**		USA	Cortez Pipeline (McElmo Dome)	geological					

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sources Part 2

				CO2 Feedstock				CO2 Feedstock		
#	Project Name	Start-up	Country	Location	Type	Owners	(%)	Operator	Contracting Structure	Reserves [Nm³]
11	**Canyon Reef Carriers Pipeline**	1972	USA		industrial (?)					
12	**Val Verde Pipeline**	1998	USA	Pecos/Terrell Counies, Texas	industrial					
13	**North East Jackson Dome Pipeline**	1985	USA	Jackson Dome, Mississippi	geological	Denbury	100			2,148E+10
14	**Free State Pipeline**	2006	USA	Jackson Dome, Mississippi	geological	Denbury	100			2,148E+10
15a	**Delta Pipeline**	2008	USA	Jackson Dome, Mississippi	geological	Denbury	100			2,148E+10
15b	**Delta Pipeline extension**	2009	USA	Jackson Dome via Tinsley Field	geological	Denbury	100			2,148E+10
16	**Cranfield**	2008	USA	Natchez, Mississippi	geological industrial	 Southern Company		Public Research Project		
17	**Weyburn-Souris Valley Pipeline**	2000	USA/CAN	Great Plains Synfuels Plant North Dakota	industrial	Dakota Gasification Company, subsidary of Basin Power Cooperative	100	Dakota Gasification Company, subsidary of Basin Electric Power Cooperative		
18	**Antelope Valley**	2012	USA/CAN	Beulah, North Dakota	power plant	Basin Electric Power Cooperative	100	Basin Electric Power Cooperative		
19	**Green Pipeline**	2010	USA	Donaldsonville, Louisiana						
20	**Snøhvit**	2007	Norway	Barents Sea	industrial	Petoro		StatoilHydro		
21	**In Salah**	2004	Algeria	no CO2 transport; gas processing plant located on top of CO2 sink	industrial					
22	**Lacq**		France	Lacq	industrial	Total	100	Total		
23	**Sleipner**	1996	Norway	no CO2 transport; gas processing plant located on top of CO2 sink	industrial					

Data Section

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sources, Part 3

				CO2 Feedstock						
#	Project Name	Start-up	Country	Location	Type	Owners	(%)	Operator	Contracting Structure	Reserves
24	**ZeroGen**	2015	Australia	Pre-feasibility study completion June 2010, Shell expects 200 km of pipeline	power plant					
25	**Alberta Carbon Trunk Line**	2012	Canada	Agrium Redwater Complex	industrial	Agrium North West Upgrading		Agrium	"long term CO2 supply agreement"	
				North West Upgrader	industrial			North West Upgrading	"long term CO2 supply agreement"	
26	**Jänschwalde**	2013	Germany	Jänschwalde	power plant	Vattenfall	100	Vattenfall		
27	**Nordjyllandsverket**	2013	Denmak	Nordjyllandsverket	power plant	Vattenfall	100	Vattenfall		
28	**Schwarze Pumpe**	2008	Germany		power plant	Vattenfall	100	Vattenfall		
29	**Callide Oxyful Project**	2011	Australia	Callida A Power Station, Queensland	power plant					
30	**Plant Barry**	2011	USA	Plant Barry, Mobile, Alabama	power plant	Alabama Power subsidary of Southern Company	100	Alabama Power		
31	**Coastal Energy Teesside**	2012	UK	Teesside, England	power plant	Coastal Energya company owned by Centrica Energy and Progressive Energy	100	Coastal Energy		
32	**Tenaska Trailblazer Energy Center**	2015	USA	Sweetwater, Texas	power plant	Tenaska Energy	100	Tenaska Energy		
33	**Hydrogen Energy California**	2014	USA	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	**Meri Pori**	2015	Finland	Meri Pori, Finland	power plant	Fortum	55			
						Teollisuuden Voima	45			
37	**Hatfiled**	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				

International CO_2 (Capture), Transport and Storage Projects: CO_2 Pipelines, Part 1

				CO2 Transport								
#	Project Name	Start-up	Country	Type	Owners	(%)	Operator	Contracting structure	Distance [km]	Size [m]	Pressure [bar]	Capacity [Nm³/d]
1	**Cortez Pipeline**	1984	USA	pipeline	Cortez Pipeline	100	Cortez Pipeline		808	0,762	130	2,954E+07
2	**McElmo Creek Pipeline**		USA	pipeline	Resolute Energy Partners	100	Resolute Energy Partners		64	0,203	130	1,611E+06
3	**Bravo Pipeline**	1984	USA	pipeline	Oxy, Kinder Morgan, XTO-Energy		BP		351	0,508	124 - 131	1,026E+07
4	**Transpetco /Bravo Pipeline**	1996	USA	pipeline	Whiting Petroleum Corp.	60	Transpetco		193	0,324		4,699E+06
5a	**Sheep Mountain (northern)**		USA	pipeline	Oxy ExxonMobil		Oxy		296	0,508		8,861E+06
5b	**Sheep Mountain (southern)**		USA	pipeline	Oxy ExxonMobil		Oxy		360	0,610	141	1,289E+07
6	**Central Basin Pipeline**		USA	pipeline	Kinder Morgan				225	0,660 - 0,406 0,356 - 0,305		1,611E+07 6,713E+06
7	**Este Pipeline**		USA	pipeline	Oxy ConocoPhillips		Oxy		64	0,305		4,296E+06
8	**Slaughter P.**		USA	pipeline	Trinity Pipeline	100	Trinity Pipeline	likely contracted to Oxy	204	0,305 - 0,203		2,685E+06
9	**West Texas P.**		USA	pipeline	Trinity Pipeline	100	Trinity Pipeline		85	0,305 - 0,203		2,685E+06
10	**Llano Lateral**		USA	pipeline	Kinder Morgan	100			225	0,406		7,250E+06

International CO_2 (Capture), Transport and Storage Projects: CO_2 Pipelines, Part 2

				CO2 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	USA	pipeline	SandRidge CO2, ARCO Permian subsidary of BP	78 22			132	0,254		
12	**Val Verde Pipeline**	1998	USA	pipeline	Genesis Energy	100	Denbury	1)	295	0,508		1,383E+07
13	**North East Jackson Dome Pipeline**	1985	USA	pipeline	Genesis Energy	100	Genesis Energy	2)	138	0,508		
14	**Free State Pipeline**	2006	USA	pipeline					50			
15a	**Delta Pipeline**	2008	USA	pipeline					109			
15b	**Delta Pipeline extension**	2009	USA	pipeline								
16	**Cranfield**	2008	USA	pipeline	Souris Valley Pipeline LTD, subsidary of Dakota Gasification Company	100	Souris Valley Pipeline LTD, subsidary of Dakota Gasification Company		330	0,356 - 3,05	186	4,028E+06
17	**Weyburn-Souris Valley Pipeline**	2000	USA/CAN						330			
18	**Antelope Valley**	2012	USA/CAN	pipeline	Souris Valley Pipeline LTD, subsidary of Dakota Gasification Company	100	Souris Valley Pipeline LTD, subsidary of Dakota Gasification Company		330	0,356 - 3,05	186	4,028E+06
19	**Green Pipeline**	2010				USA						
20	**Snøhvit**	2007	Norway	pipeline	Denbury	100			515	0,610		2,148E+07
21	**In Salah**	2004	Algeria	pipeline					143	0,203		9,695E+05
22	**Lacq**		France									
23	**Sleipner**	1996	Norway	pipeline	Total	100	Total		30		30	

1) "twenty-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."

International CO_2 (Capture), Transport and Storage Projects: CO_2 Pipelines, Part 3

				CO2 Transport								
#	Project Name	Start-up	Country	Type	Owners	(%)	Operator	Contracting structure	Distance [km]	Size [m]	Pressure [bar]	Capacity [Nm³/d]
24	**ZeroGen**	2015	Australia									
25	**Alberta Carbon Trunk Line**	2012	Canada	pipeline	Enhance Energy	100			240	0,406 - 0,324		8,056E+06
26	**Jänschwalde**	2013	Germany	pipeline					150			
27	**Nordjyllandsverket**	2013	Denmak	pipeline					30			
28	**Schwarze Pumpe**	2008	Germany									
29	**Callide Oxyful Project**	2011	Australia	truck					300			
30	**Plant Barry**	2011	USA	pipeline	SECARB		SECARB		16			2,078E+05
31	**Coastal Energy Teesside**	2012	UK	pipeline	COOTS, owned by Centrica	100	COOTS					
32	**Tenaska Trailblazer Energy Center**	2015	USA	pipeline	plant site not determined; will probally utilize Canyon Reef Carriers Pipeline				~ 60			
33	**Hydrogen Energy California**	2014	USA	pipeline								
34	**Goldenbergwerk**	2015	Germany	pipeline	RWE DEA							
35	**Boundary Dam**	2015	Canada	pipeline								
36	**Meri Pori**	2015	Finland	ship								
37	**Hatfiled**	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

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sinks, Part 1

				CO2 Sink							
#	Project Name	Start-up	Country	Type	Location	Owners	(%)	Operator	Start of Operation	Contracting Structure	Total Capacity [Nm³]
1	**Cortez Pipeline**	1984	USA	EOR	Denver City Hub, Texas						
2	**McElmo Creek Pipeline**		USA	EOR	McElmo Creek Unit, Utah	Resolute Energy Partners multiple private	75	Resolute			
3	**Bravo Pipeline**	1984	USA	EOR	Denver City Hub, Texas						
4	**Transpetco /Bravo Pipeline**	1996	USA	EOR	Postle Field, Oklahoma	Whiting Petroleum Corp.	100				
5a	**Sheep Mountain (northern)**		USA	EOR	Denver City Hub, Texas; via Bravo Dome						
5b	**Sheep Mountain (southern)**		USA	EOR	Denver City Hub, Texas						
6	**Central Basin Pipeline**		USA	EOR	Salt Creek Terminus	Oxy					
7	**Este Pipeline**		USA	EOR	Salt Creek Terminus	Oxy					
8	**Slaughter P.**		USA	EOR	Slaughter Field						
9	**West Texas P.**		USA	EOR	Hobbs Field, Keystone Field, Two Freds Field						
10	**Llano Lateral**		USA	EOR	Vauum Unit, Maljamar, C. Vac						

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sinks, Part 2

				CO2 Sink							
#	Project Name	Start-up	Country	Type	Location	Owners	(%)	Operator	Start of Operation	Contracting Structure	Total Capacity [Nm³]
11	**Canyon Reef Carriers Pipeline**	1972	USA	EOR	SARCO Field	Kinder Morgan					
12	**Val Verde Pipeline**	1998	USA	EOR	SARCO Field	Kinder Morgan					
13	**North East Jackson Dome Pipeline**	1985	USA	EOR	Little Creek Field	Denbury	100	Denbury	1999		
14	**Free State Pipeline**	2006	USA	EOR	Eucutta, Soso, Martinville and Heidelberg Field, Mississippi	Denbury	100	Denbury	2006		
15a	**Delta Pipeline**	2008	USA	EOR	Tinsley Field	Denbury	100	Denbury			
15b	**Delta Pipeline extension**	2009	USA	EOR	Delhi Field	Denbury	100	Denbury	2009		
16	**Cranfield**	2008	USA	EOR Saline	Cranfield Oil Field, Natchez, Miss,	Denbury Resources ?	100				
17	**Weyburn-Souris Valley Pipeline**	2000	USA/CAN	EOR	Weyburn field, Saskatchewan, Canada	EnCana	100	EnCana			3,564E+07
18	**Antelope Valley**	2012	USA/CAN								
19	**Green Pipeline**	2010			Hastings Field, Texas	Denbury					
20	**Snøhvit**	2007	Norway								
21	**In Salah**	2004	Algeria								
22	**Lacq**		France	depleted gas field	Rousse field	Total	100	Total			
23	**Sleipner**	1996	Norway								

International CO_2 (Capture), Transport and Storage Projects: CO_2 Sinks, Part 3

				CO2 Sink							
#	Project Name	Start-up	Country	Type	Location	Owners	(%)	Operator	Start of Operation	Contracting Structure	Total Capacity [Nm³]
24	**ZeroGen**	2015	Australia								
25	**Alberta Carbon Trunk Line**	2012	Canada	EOR	Clive, Alberta, Canada	Enhance Engery		Enhance Energy			
26	**Jänschwalde**	2013	Germany								
27	**Nordjyllandsverket**	2013	Denmak		Vedsted underground structure						
28	**Schwarze Pumpe**	2008	Germany								
29	**Callide Oxyful Project**	2011	Australia	depleted gas field	Dension Trough	Santos	50		1989		
30	**Plant Barry**	2011	USA	EOR	Citronelle Oil Field			SECARB			
31	**Coastal Energy Teesside**	2012	UK	EOR							
32	**Tenaska Trailblazer Energy Center**	2015	USA								
33	**Hydrogen Energy California**	2014	USA	EOR	Elk Hills Ooil Field	Oxy					
34	**Goldenbergwerk**	2015	Germany	saline reservoir	Schleswig-Holstein (?)						
35	**Boundary Dam**	2015	Canada	EOR							
36	**Meri Pori**	2015	Finland	EOR							
37	**Hatfiled**	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					