Zero emissions platform

The Costs of CO_2 Capture, Transport and Storage

Post-demonstration CCS in the EU

European Technology Platform for Zero Emission Fossil Fuel Power Plants

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Introduction

Founded in 2005 on the initiative of the European Commission, the European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as the Zero Emissions Platform, or ZEP) represents a unique coalition of stakeholders united in their support for CO_2 Capture and Storage (CCS) as a critical solution for combating climate change. Indeed, it is not possible to achieve EU or global CO_2 reduction targets cost-effectively *without* CCS, providing 20% of the global cuts required by 2050.[1] Members include European utilities, oil and gas companies, equipment suppliers, national geological surveys, academic institutions and environmental NGOs. The goal: to make CCS commercially available by 2020 and accelerate wide-scale deployment.

ZEP is an advisor to the EU on the research, demonstration and deployment of CCS. In 2006, it therefore launched its first Strategic Deployment Document (SDD) and Strategic Research Agenda (SRA).[2] The conclusion: an integrated network of CCS demonstration projects should be implemented urgently EU-wide. This was followed by an in-depth study[3] into how such a demonstration programme could work in practice, from every perspective – technological, operational, geographical, political, economic and commercial.

This approach was incorporated into the European Commission's policy framework and by 2009, two key objectives had been met: to establish funding for an EU CCS demonstration programme and a regulatory framework for CO_2 storage. An updated SDD followed in 2010.[4]

Now, ZEP's Taskforce Technology has undertaken a study into the costs of complete CCS value chains – i.e. the capture, transport and storage of CO_2 – estimated for new-build coal- and natural gas-fired power plants, located at a generic site in Northern Europe from the early 2020s. Utilising new, in-house data provided by ZEP member organisations, it establishes a reference point for the costs of CCS, based on a "snapshot" in time (all investment costs are referenced to the second quarter of 2009).

Three Working Groups were tasked with analysing the costs related to CO_2 capture, CO_2 transport and CO_2 storage respectively. The resulting integrated CCS value chains, based on these three individual reports,[5] are presented in this summary report. (For a complete picture of how the results were obtained, and all underlying assumptions, please refer to the three individual reports.)

ZEP acknowledges that the costs of CCS will be inherently uncertain until further projects come on stream. The study therefore does not provide a forecast of how costs will develop over time, but will be updated every two years in line with technological developments and the progress of the EU CCS demonstration programme. While this study focuses on power generation, future updates will also refer to co-firing with biomass, combined heat and power plants, and the role of industrial applications in greater detail.

1 International Energy Agency (IEA), World Energy Outlook, 2009
2 This included a first assessment of CO_2 capture costs, detailed in the underlying report, "The final report from Working Group 1 – Power Plant and Carbon Dioxide Capture", October 2006
3 www.zeroemissionsplatform.eu/library/publication/2-eu-demonstration-programme-co-2-capture-storage.html
4 www.zeroemissionsplatform.eu/library/publication/125-sdd.html
5 www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html; www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html; www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

Key conclusions

- **Post 2020, CCS will be cost-competitive with other low-carbon energy technologies**
  The EU CCS demonstration programme will not only validate and prove the costs of CCS technologies, but form the basis for future cost reductions, enhanced by the introduction of second- and third-generation technologies. The results of the study therefore indicate that post-demonstration CCS will be cost-competitive with other low-carbon energy technologies as a reliable source of low-carbon power. CCS is on track to become one of the key technologies for combating climate change – within a portfolio of technologies, including greater energy efficiency and renewable energy.

- **CCS is applicable to both coal- and natural gas-fired power plants**
  CCS can technically be applied to both coal- and natural gas-fired power plants. Their relative economics depend on power plant cost levels, fuel prices and market positioning, whereas applicability is mainly determined by load regime.

- **All three CO_2 capture technologies could be competitive once successfully demonstrated**
  The study includes the three main capture technologies (post-combustion, pre-combustion and oxy-fuel), but excludes second-generation technologies (e.g. chemical looping, advanced gas turbine cycles). Using agreed assumptions and the Levelised Cost of Electricity as the main quantitative value, there is currently no clear difference between any of the capture technologies and all could be competitive in the future once successfully demonstrated. The main factors influencing total costs are fuel and investment costs.

- **Early strategic planning of large-scale CO_2 transport infrastructure is vital to reduce costs**
  Clustering plants to a transport network can achieve significant economies of scale – in both CO_2 transport *and* CO_2 storage in larger reservoirs, on- and offshore. Large-scale CCS therefore requires the development of a transport infrastructure on a scale matched only by that of the current hydrocarbon infrastructure. As this will lead to greatly reduced long-term costs, early strategic planning is vital – including the development of clusters and over-sized pipelines – with any cross-border restrictions removed.

- **A risk-reward mechanism is needed to realise the significant aquifer potential for CO_2 storage**
  Location and type of storage site, reservoir capacity and quality are the main determinants for the costs of CO_2 storage: onshore is cheaper than offshore; depleted oil and gas fields (DOGF) are cheaper than deep saline aquifers (SA); larger reservoirs are cheaper than smaller ones; high injectivity is cheaper than poor injectivity. Given the large variation in storage costs (up to a factor of 10) and the risk of investing in the exploration of SA that are ultimately found to be unsuitable, a risk-reward mechanism is needed to realise their significant potential and ensure sufficient storage capacity is available – in the time frame needed.

- **CCS requires a secure environment for long-term investment**
  Based on current trajectories, the price of Emission Unit Allowances (EUAs) under the EU Emissions Trading System will not, initially, be a sufficient driver for investment after the first generation of CCS demonstration projects is built (2015-2020). Enabling policies are therefore required in the intermediate period – after the technology is commercially proven, but before the EUA price has increased sufficiently to allow full commercial operation. The goal: to make new-build power generation with CCS more attractive to investors than without it.

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Executive summary

A complete analysis of CCS costs in the EU post 2020

Costs for different CO_2 capture, transport and storage options were first determined using data for the three main capture technologies (post-combustion, pre-combustion and oxy-fuel) applied to hard coal, lignite and natural gas-fired power plants; the two main transport options (pipelines and ships); and the two main storage options (depleted oil and gas fields, and deep saline aquifers), both on- and offshore.

The results were then combined in order to identify:

1. *Total costs for full-scale, commercial CCS projects in the EU post 2020*
2. *Key trends and issues for various deployment scenarios*
3. *The impact of fuel prices, economies of scale and other factors, e.g. economic.*

Utilising new, in-house data provided by ZEP member organisations

Publicly available cost data on CCS are scarce. In order to obtain a reliable base for the estimations, it was therefore decided to use new, in-house data provided exclusively by ZEP member organisations – 15 in total. This included five independent power companies and manufacturers of power plant equipment for CO_2 capture.

In order to access the data, all basic cost information was kept confidential, regarding both source and individual numbers. To this end, one person per area was assigned to collect the information, align it, create mean values and render it anonymous. However, all contributors to the study, including those who provided detailed economic data, are named in Annex II. (In future updates ZEP intends to improve the transparency of data provision, without breaching confidentiality.)

Power plants with CO_2 capture – from demonstration towards maturity

CO_2 capture comprises the majority of CCS costs. It is an emerging technology and historical experience with comparable processes shows that significant improvements are achievable – traditionally referred to as learning curves. While this study does not provide a forecast of how costs will develop over time, the following notations have been applied:

- A **base ("BASE") power plant** with CO_2 capture represents today's technology choices and full economic risk, margins, redundancies and proven components – as the very first units to be built following the demonstration phase. This constitutes a conservative cost level in the early 2020s.
- An **optimised ("OPTI") power plant** with CO_2 capture represents those units commissioned *after* the first full-size CCS plants have been in operation (~2025), including technology improvements, refined solutions, improved integration, but still using the three main capture technologies. These represent optimised cost estimations, based on first commercial experience.

In short, BASE and OPTI represent normal technology refinement and development following a successful demonstration (but not a mature technology, which will only be available in the longer term).

Taking fuel cost variations into account

The fuel costs used in this study are the best estimation of a representative fuel cost in 2020. Due to the considerable uncertainty – especially in the case of natural gas, where there is a wide difference of opinion on the impact of shale gas on future prices – it was decided to use Low, Middle and High values for both natural gas and hard coal.

The ranges were selected during Q4 2010 and are consistent with detailed reviews such as the EC Second Strategic Energy Review of November 2008[6] for the year 2020 (assuming the Base Case of Average Oil Scenarios) and the UK Electricity Generation Cost Update, June 2010.[7]

For details of all major assumptions, see pages 10-14.

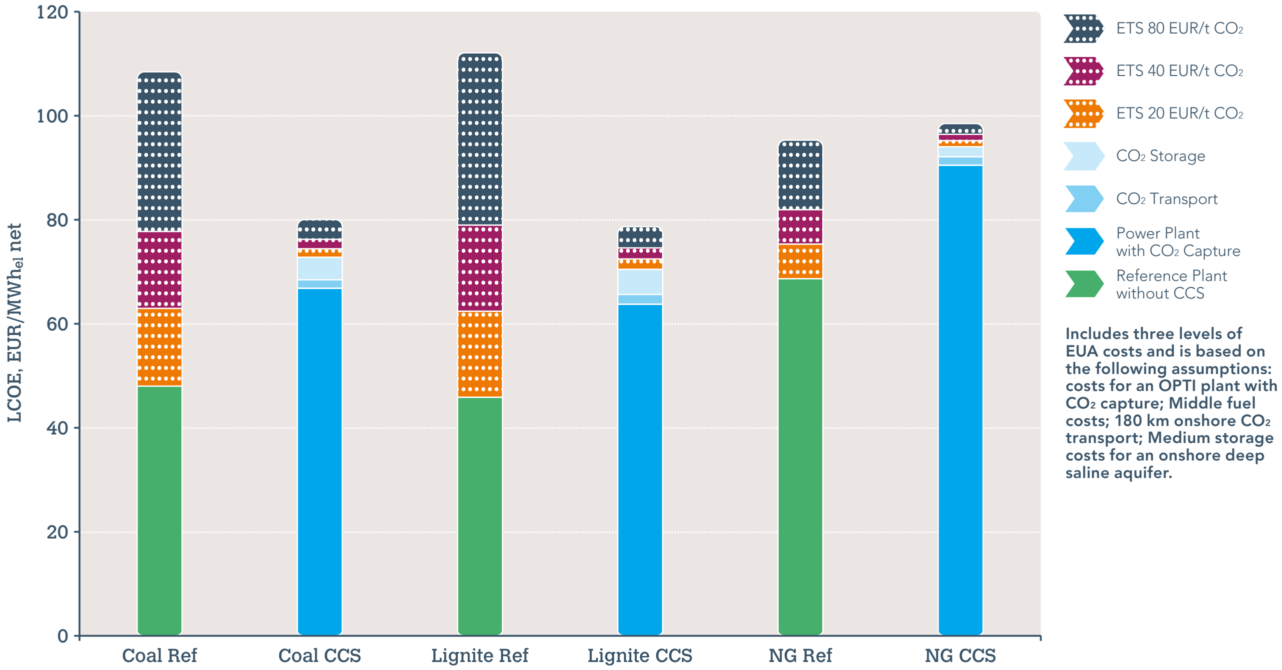
MAJOR RESULTS

a) Integrated CCS projects

As each part of the CCS value chain includes multiple variants, the results provide a probable (but not complete) set of combinations. This includes a single plant to a single "sink" (storage site) and a cluster of plants to a cluster of sinks, with a sensitivity analysis provided per combination. In order to calculate CO_2 capture and avoidance costs, reference power plants *without* CO_2 capture were also established:

- A **natural gas-fired** single-shaft F-class Combined Cycle Gas Turbine producing 420 MW_{el} net, at an efficiency of 58-60% (LHV) for BASE and OPTI plants respectively at €45-90/MWh depending on the fuel cost.
- For **hard coal**, a 736 MW_{el} net pulverised fuel (PF) ultra supercritical power plant at €40-50/MWh; for lignite, a PF-fired 989 MW_{el} net ultra supercritical plant and a lignite-fired 920 MW_{el} net PF ultra supercritical power plant with pre-drying of the lignite. All have steam conditions 280 bar 600/620°C live steam data.

Figure 1: The Levelised Cost of Electricity (LCOE) of integrated CCS projects (blue bars) compared to the reference plants without CCS (green bars)



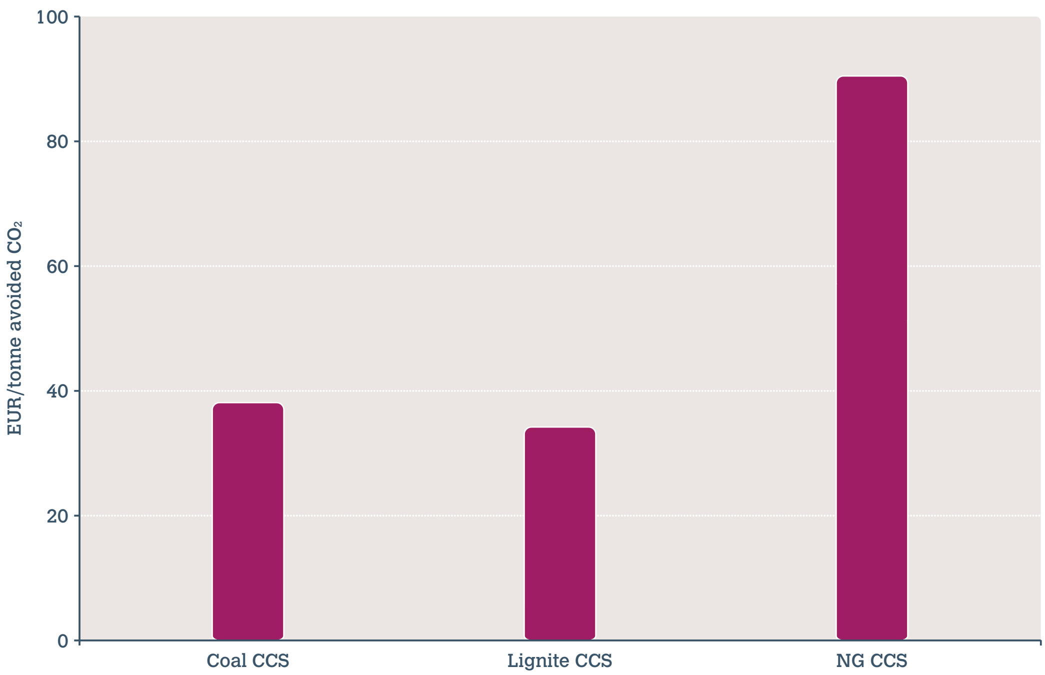
[6] http://ec.europa.eu/energy/strategies/2008/2008_11_ser2_en.htm
[7] www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

- Following the demonstration phase, the application of CCS to fossil fuel power plants will result in higher electricity generating costs (e.g. increasing from ~€50/MWh up to ~€70/MWh for hard coal, excluding EUA costs). Corresponding CO_2 avoidance costs, compared to the reference plants with the same fuel, are shown in Figure 2 below.

- The two coal cases are similar in cost (~€70/MWh excluding EUA costs), while the gas case shows a higher cost (~€95/MWh excluding EUA costs). At lower EUA prices, the coal cases with CCS also come out more favourably than the gas case when compared to the reference plants. However, depending on different assumptions, the competitiveness of the technologies changes, with gas CCS becoming competitive at gas prices <€6/GJ. Gas CCS plants also produce less than half the amount of CO_2 to be captured per MWh than coal, resulting in lower transport and storage costs per MWh.

- The blue bars show that the combined cost of the power plant with capture comprises 80-90% of the total LCOE (~75% of the additional LCOE for CCS vs. the reference plants). However, CO_2 transport and storage to a large extent determine the location and decision to proceed with a project. Posing substantial development and scale-up challenges, costs are dominated by upfront investments, while any reward depends on volume streams, suitability of the storage site, utilisation and the development of an infrastructure (see below). While capture technology will be chosen based on a calculable economy, transport and storage costs therefore depend on the suitability of the chosen solution.

Figure 2: CO_2 avoidance costs for possible plants commissioned in the mid 2020s – the price of EUAs required to justify building CCS projects vs. a plant without CCS from a purely economic point of view (calculated on the same basis as Figure 1)



[8] This is in accordance with EU estimates of EUA prices for 2025: http://ec.europa.eu/clima/documentation/roadmap/docs/sec_2011_288_en.pdf

- Figure 2 shows that the associated EUA break-even cost corresponds to a price of €37/tonne of CO_2 for hard coal; ~€34/tonne of CO_2 for lignite; and ~€90/tonne of CO_2 for gas. At an EUA price of €35/tonne of CO_2,[8] these full-size, coal-fired CCS power plants are therefore close to becoming commercially viable, while the gas case is not. However, unabated gas power plants remain a commercial option, as shown in Figure 1.

N.B. Costs for OPTI plants assume a completely successful demonstration of the technology and/or that the first full-size CCS plants (following the EU CCS demonstration programme) have already been in operation. All reported costs exclude the exceptional development and other costs associated with the demonstration programme itself.

Post 2020, CCS will be cost-competitive with other low-carbon energy technologies.

For detailed results on integrated CCS projects, see pages 15-26.

b) CO_2 Capture

Capture costs were determined for first-generation capture technologies which will probably be ready for deployment in the early 2020s: post-combustion, IGCC with pre-combustion and oxy-fuel. All three were applied to hard coal and lignite-fired power plants, while post-combustion was applied to natural gas.

- On an LCOE basis, there is no significant difference between the three capture technologies for coal (within the available accuracy): hard coal-fired power plants without capture have an LCOE of ~€48/MWh (excluding EUA costs), rising to €65-70/MWh[9] with capture for an OPTI plant. However, complexity differs considerably between the three options and none will become fully commercial until several large-scale plants have been operating following the demonstration phase. Achieving high plant availability is therefore key to keeping costs competitive.

- Natural gas-fired power plants without capture have an LCOE of ~€70/MWh, rising to ~€90/MWh with capture.[9] However, as they have a different cost structure to coal-fired CCS plants – with a lower capital cost and higher fuel costs – the LCOE is competitive with coal[9] if the gas price is low. At an EUA price of ~€35/tonne of CO_2, unabated gas (at €5/GJ) is also competitive with coal with CCS.[9]

- CO_2 avoidance costs against a reference plant with the same fuel *calculated at the fence of the plants* therefore give <€30/tonne of CO_2 avoided for lignite; just over €30/tonne for hard coal; and ~€80/tonne for natural gas. (All figures exclude transport and storage costs.)

- On a unit basis, small power plants are more expensive than large; BASE plants are more expensive than OPTI plants. As the less expensive option will always be chosen during the first 10 years of deployment, the lower figures in this study are the most likely to represent CCS plants commissioned in the early 2020s. During this period, the three main capture options will also develop considerably, in parallel with second- and third-generation technologies.

All three CO_2 capture technologies could be competitive once successfully demonstrated.

For detailed results on CO_2 capture, see pages 27-31 and the underlying report: www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html

[9] At Middle fuel prices

c) CO_2 Transport

The study presents detailed cost elements and key cost drivers for the two main methods of CO_2 transportation: pipelines and ships. These can be combined in a variety of ways – from a single source to a single sink, developing into qualified systems with several sources, networks and several storage sites over time. Several likely transport networks of varying distances are therefore presented, with total annual costs and a cost per tonne of CO_2 transported. The cost models operate with three legs of transport: feeders, spines and distribution, each of which may comprise on-/offshore pipelines or ships.

- The results show that pipeline costs are roughly proportional to distance, while shipping costs are fairly stable over distance, but have "step-in" costs, including (in this study) a stand-alone liquefaction unit potentially remote from the power plant. Pipelines also benefit significantly from scale, whereas the scale effects on ship transport costs are less significant.

- Typical costs for a short onshore pipeline (180 km) and a small volume of CO_2 (2.5 Mtpa) are just over €5/tonne of CO_2. This reduces to ~€1.5/tonne of CO_2 for a large system (20 Mtpa). Offshore pipelines are more expensive at ~€9.5 and €3.5/tonne of CO_2 respectively, for the same conditions. If length is increased to 500 km, an onshore pipeline costs €3.7/tonne of CO_2 and an offshore pipeline ~€6/tonne of CO_2.

- For ships, the cost is less dependent on distance: for a large transport volume of CO_2 (20 Mtpa) costs are ~€11/tonne for 180 km; €12/tonne for 500 km; and ~€16/tonne for very long distances (1,500 km), including liquefaction. For a smaller volume of CO_2 (2.5 Mtpa), costs for 500 km are just below €15/tonne, including liquefaction.

- For short to medium distances and large volumes, pipelines are therefore by far the most cost-effective solution, but require strong central coordination. Since high upfront costs, CAPEX and risk are barriers to rapid CCS deployment, combining ship and pipeline transport via the development of clusters could provide cost-effective solutions, especially for volume ramp-up scenarios. However, this entails the development of an infrastructure – including start-up costs, central planning and the removal of any cross-border restrictions. Technology and final costs therefore appear to be less of an issue than the development of a rational system for transport.

Early strategic planning of large-scale CO_2 transport infrastructure is vital to reduce costs.

For more detailed results on CO_2 transport, see pages 32-34 and the underlying report: www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html

d) CO_2 Storage

Publicly available data on CO_2 storage costs barely exists. A "bottom-up" approach was therefore taken, using cost components provided by ZEP members with an in-depth knowledge of closely linked activities and consolidated into a robust, consistent model. In order to cover the range of potential storage configurations and still provide reliable cost estimates, storage was divided into six main "typical" cases, according to major differentiating elements: depleted oil and gas fields (DOGF) vs. deep saline aquifers (SA); offshore vs. onshore; and whether existing ("legacy") wells were re-usable.

- The cost range is large – from €1 to €20/tonne of CO_2. On the assumption that the cheaper available storage sites will be developed first, and the more expensive when capacity is required, it could be argued that storage costs for the early commercial phase will be at the low/medium levels of the defined ranges for onshore SA at €2-12/tonne;

[10] In the commercial phase

onshore DOGF at €1-7/tonne; offshore SA (with the largest capacities) at €6-20/tonne; and offshore DOGF at €2-14/tonne. In other words:
– onshore is cheaper than offshore
– DOGF are cheaper than SA (particularly if they have re-usable legacy wells)
– offshore SA show the highest costs and the widest cost range
– sensitivity is dominated by field capacity, injection rate and depth.

- The availability and capacity of suitable storage sites developed into a key consideration. In terms of numbers, the majority of suitable sites are below the estimated capacity of 25-50 Mt, which corresponds to the need for more than five reservoirs to store 5 Mtpa[10] of CO_2 for 40 years; the majority of estimated capacity is found in very large DOGF and SA (>200 Mt capacity).

- In conclusion, CO_2 storage capacity is available in Europe. However, the best known storage sites are also the smallest and not sufficient for a larger system. Offshore – followed by onshore – SA have the largest potential, but also the highest costs. If the best options can be used, costs could be as low as a few €/tonne, rising to tens of €/tonne if the larger and more remote SA have to be used. Developers of these more efficient, but less known, storage sites must therefore be rewarded for taking on the risk and upfront costs required for their exploration and development.

Given the large variation in storage costs and the risk of investing in the exploration of deep saline aquifers that are ultimately found to be unsuitable, a risk-reward mechanism is needed to realise their significant potential.

For more detailed results on CO_2 storage, see pages 35-37 and the underlying report: www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html.

Sensitivities

A sensitivity analysis of the cost results was calculated for a supercritical OPTI hard coal-fired power plant, with post-combustion capture and storage in an onshore SA. This shows that fewer running hours result in a much higher cost (€19/MWh higher LCOE when plant load factor reduces from 7,500 to 5,000 hours per year). CAPEX and WACC also give relatively large variations, which is to be expected given that capital costs dominate for a coal-fired power plant: +/– 25% CAPEX leads to LCOE changes of +/– €8/MWh; +/–2% points from the 8% WACC leads to LCOE changes of +€6/–€5/MWh).

Plant life, however, shows a low sensitivity since the cost calculation is based on the net present value of the investment. Storage costs also make a small contribution to overall costs. Due to the relatively cheap fuel, the efficiency of the capture (absorption–desorption) process is also less important, while fuel costs as such have a larger impact. (Changing the Middle fuel cost from €2.4/GJ to a Low €2/GJ and a High €2.9/GJ leads to LCOE changes of –€4/+€5/MWh.)

Due to the cost structure for a natural gas-fired CCS power plant – with substantially lower investment costs, somewhat lower O&M costs and almost three times higher fuel costs – the total sensitivity is the reverse, i.e. much more influenced by fuel cost and less by capital.

Methodology

A complete analysis of CCS costs in the EU post 2020

The ZEP cost study presents best current estimates for full-scale commercial CCS in the power sector in Europe post 2020, based on new, in-house data provided by member organisations. The final results assume that all elements of the value chain have been successfully demonstrated in the EU CCS demonstration programme and other demonstration initiatives worldwide.

Three Working Groups within ZEP's Taskforce Technology first analysed the costs related to CO_2 capture, CO_2 transport and CO_2 storage respectively. The results of these three individual reports[11] were then combined to give total costs for integrated CCS projects

a) Utilising new, in-house data from ZEP member organisations

It is theoretically possible to obtain basic data on CCS technologies from several sources. However, most public reports have either used budget offers from manufacturers, quoted other studies, or calculated equipment costs from academic models. Several ZEP members have had difficulties obtaining relevant information for their specific situation and therefore undertaken a considerable amount of work themselves. Costs also differ significantly between different regions, such as the USA, Asia and Europe; and vary in time, as several public cost indices illustrate.

As reliable external cost data proved scarce, it was therefore decided to utilise the technical and economical knowledge of ZEP members who either manufacture, or have substantial research and experimental experience in CCS – 15 organisations in total. (This included five independent power companies and manufacturers of power plant equipment for CO_2 capture.) Indeed, many are already undertaking detailed engineering studies for CCS demonstration projects, encompassing the entire value chain. Power companies regularly cooperate with several manufacturers and are even now building plants of the kind described here (currently without CCS). The oil and gas industry also has decades of experience with natural gas analogues for the majority of the transport and storage chain.

Thanks to the diverse representation within ZEP, data covering all aspects of the costs and technology performance were therefore assembled, with important CAPEX figures (and appropriate contingencies) for the coal-fired CO_2 capture cases provided by the power companies and equipment suppliers from engineering studies completed to date.

In order to access the data, all basic cost information was kept confidential, regarding both source and individual numbers. To this end, one person per area (the co-author of the underlying report) was assigned to collect the information; compare and adjust it if large discrepancies were apparent; create mean values; and render it anonymous. However, all contributors to the study, including those who provided detailed economic data, are named in Annex II. In future updates, ZEP intends to improve the transparency of data provision, without breaching confidentiality.

N.B. Data for this report were collected in spring 2010, but in order to align them, all sources were recalculated by indices to the second quarter of 2009.

[11] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html;
www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html;
www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

b) Power plants with CO_2 capture – from demonstration towards maturity

Contributors of basic data were also asked if they could illustrate the development of both costs and technical solutions over time. Since the answers were not totally consistent – and included other considerations besides pure technology development – the results are not presented in the context of traditional learning curves. However, the following notations were applied:

- **A base ("BASE") power plant with CO_2 capture** represents today's technology choices – including full economic risk, margins, redundancies and proven components – as the very first units to be built following the demonstration phase. This constitutes a conservative cost level in the early 2020s.

- **An optimised ("OPTI") power plant with CO_2 capture** represents those units commissioned after the first full-size CCS plants have been in operation (~2025), including technology improvements, but not a completely new technology, e.g. improved steam data of the plant; improved energy utilisation in conventional equipment; higher level of plant integration; lower risk margins etc. In short, normal product development based on first commercial experience.

In short, BASE and OPTI represent normal technology refinement and development following a successful demonstration (but not a mature technology, which will only be available in the longer term).

See page 17 for a more detailed description of BASE and OPTI methodologies.

c) The application of CCS to carbon-intensive industrial sectors

This study focuses on CCS for power generation, but it could also potentially reduce CO_2 emissions from the steel, cement, refineries/petrochemical and other industries. Some of the applied processes in these industries have higher concentrations of CO_2 in some of their off-gases (natural gas processing, cement, steel, hydrogen manufacturing for refineries, ammonia production etc.) which could lead to comparable or lower capture costs than those for coal.

However, the variety, uniqueness and scale of industrial production processes will lead to a wide range of capture costs and less generic solutions which are not easy to compare. ZEP will therefore seek cooperation with relevant industries in order to reference the costs of industrial CCS applications – including biomass-based applications – in future updates of the ZEP cost report.

d) Major assumptions

For consistency, a number of common assumptions were established and applied across all three Working Groups. These are presented below in order to allow full transparency and comparisons with specific projects. The sensitivity of changes to these basic assumptions were also analysed and the results are given below.

Economic assumptions

Volatility in plant and equipment costs, short- and long-term costs and currency developments have been addressed by indexing all estimates to one specific period – the second quarter of 2009. Any user of the cost data in this report is therefore advised to estimate and adjust for developments after this period. The cost basis is European and all reported costs are in euros; currency exchange rates representative of the actual date of original studies have been used.

A real (without inflation) cost of capital for investments, here designated as WACC (Weighted

Average Cost of Capital), is assumed to be 8% (with sensitivity evaluated for 6% and 10%). The chosen real WACC reflects required return on equity and interest rates on loans and it is assumed that the inflation rate is equal for all costs and incomes during the project life. The required CAPEX has been annualised and discounted back to the present using the WACC.

The fuel costs used in this study are the best estimation of a representative fuel cost in 2020. Owing to the considerable uncertainty – especially in the case of natural gas, where there is a wide difference of opinion on the impact of shale gas on future prices – it was decided to use Low, Middle and High values for both natural gas and hard coal. The ranges were selected during Q4 2010 and are consistent with detailed reviews such as the EC Second Strategic Energy Review of November 2008[12] for the year 2020 (assuming the Base Case of Average Oil Scenarios), and the current UK Electricity Generation Cost Update.[13]

The following fuel costs were selected for the study:

Fuel Costs	Low	Middle	High
Hard coal - €/GJ	2.0	2.4	2.9
Lignite - €/GJ	1.4	1.4	1.4
Natural gas - €/GJ	4.5	8.0	11.0

For electricity consumptions for CO_2 transport and storage operations (beyond the power plants), an electricity purchase price of €0.11/kWh was found to be representative. The agreed CCS project lifetime is 40 years for commercial hard coal-based and lignite-based projects; 25 years for natural gas turbine-based projects.

Technical assumptions

Due to the inherently high investments for thermal power plants with CO_2 capture, it is assumed that all power plants will operate in base load, operating for 7,500 hours equivalent full load each year. This is also consistent with the fact that a CCS plant, if realised, will have a lower variable operations cost than a corresponding plant without CCS (when including the EUA price) and thus always be dispatched before any other fossil fuel power plant, including gas. The only reason why a CCS plant would not work in base load mode is either because there is more prioritised power (e.g. Wind) available than is needed, or if the technical availability is lower.

Power plant concepts with CO_2 capture

The technologies studied are first-generation capture technologies: post-combustion CO_2 capture; IGCC with pre-combustion capture; and oxy-fuel, adapted to hard coal, lignite and natural gas, as applicable. For each technology, a range of costs was developed for BASE and OPTI power plants (see above).

For hard coal-fired and lignite-fired power plants, the following power plant concepts were used:

- PF ultra supercritical (280 bar 600/620°C steam cycle) power plant with post-combustion capture based on advanced amines.

- Oxygen-blown IGCC with full quench design, sour shift and CO_2 capture with F-class Gas Turbine (diffusion burners with syngas saturation and dilution).

- Oxy-fired PF power plant with ultra supercritical steam conditions (280 bar 600/620°C steam cycle).

For the integrated CCS projects, average expected values have been used for OPTI plants with capture, since the costs for the plant concepts are similar. For hard coal-fired power plants, average sizes and quantities of captured CO_2 for one power plant block are:
- Net electric capacity: ~700 MW_{el}
- Captured CO_2: 0.85 t/MWh_{el} net, ~4.5 Mt/year.

[12] http://ec.europa.eu/energy/strategies/2008/2008_11_ser2_en.htm
[13] www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

For lignite-fired power plants, average sizes and quantities of captured CO_2 for one power plant block are:
- Net electric capacity: ~800 MW_{el}
- Captured CO_2: 0.95 t/MWh_{el} net, ~5.5 Mt /year.

For natural gas-fired Combined Cycle Gas Turbines (CCGT) power plants for the integrated CCS projects with OPTI post-combustion CO_2 capture (based on an advanced amine), the sizes and quantities of captured CO_2 for one power block (consisting of one single-shaft F-class CCGT) are:
- Net electric capacity: ~350 MW_{el}
- Captured CO_2: 0.33 t/MWh_{el} net, ~1 Mt/year.

Reference power plants concepts without CO_2 capture

The corresponding reference power plants without CO_2 capture used in this study are:

- Natural gas-fired single-shaft F-class Combined Cycle Gas Turbine producing 420 MW_{el} net at an efficiency of 58% (LHV and BASE) or 60% (LHV and OPTI).

- Hard coal 736 MW_{el} net pulverised fuel (PF) ultra supercritical (280 bar 600/620°C steam cycle) power plant.

- Lignite-fired 989 MW_{el} net PF ultra supercritical (280 bar 600/620°C steam cycle) power plant and a lignite-fired 920 MW_{el} net PF ultra supercritical (280 bar 600/620°C steam cycle) power plant with pre-drying of the lignite.

A key assumption for the design of the entire CCS chain concerns production volumes and profiles. Based on the power plant concepts with CO_2 capture, three different annual CO_2 volumes have been considered:

- 2.5 million tonnes per annum (Mtpa) representing a commercial natural gas-fired plant with CCS (a plant with two power blocks), or a coal-based demonstration project.

- 10 Mtpa representing a full-scale commercial coal-fired power plant with CCS (a plant with two power blocks).

- 20 Mtpa representing a typical full-scale, mature CCS cluster.

The production profile is assumed to be linear, with equal hourly production rates of 333, 1,330 and 2,660 tonnes CO_2/hour respectively during the 7,500 hours per year. In reality, a wide variety of volumes will be present, but the three categories illustrate the possible modus operandi for the systems.

Boundary conditions

Boundaries between the three elements of capture, transport and storage have been defined as follows:

- *Compression/liquefying/processing of the captured CO_2 to meet the requirements of the initial transport process* are included in the design and cost of the power plants with CO_2 capture. The assumed delivery conditions for CO_2 from the capture plant are:
  - 110 bar and ambient temperature (max. 30°C) for *pipeline as initial transport*, with CO_2 quality requirements that should permit the use of cost-effective carbon steel materials in CO_2 pipelines and meet health and safety requirements.
  - 7 bar and -55°C for *ship as initial transport*, with CO_2 quality as above for pipelines, but with a water content low enough to allow carbon steel for the logistic system.

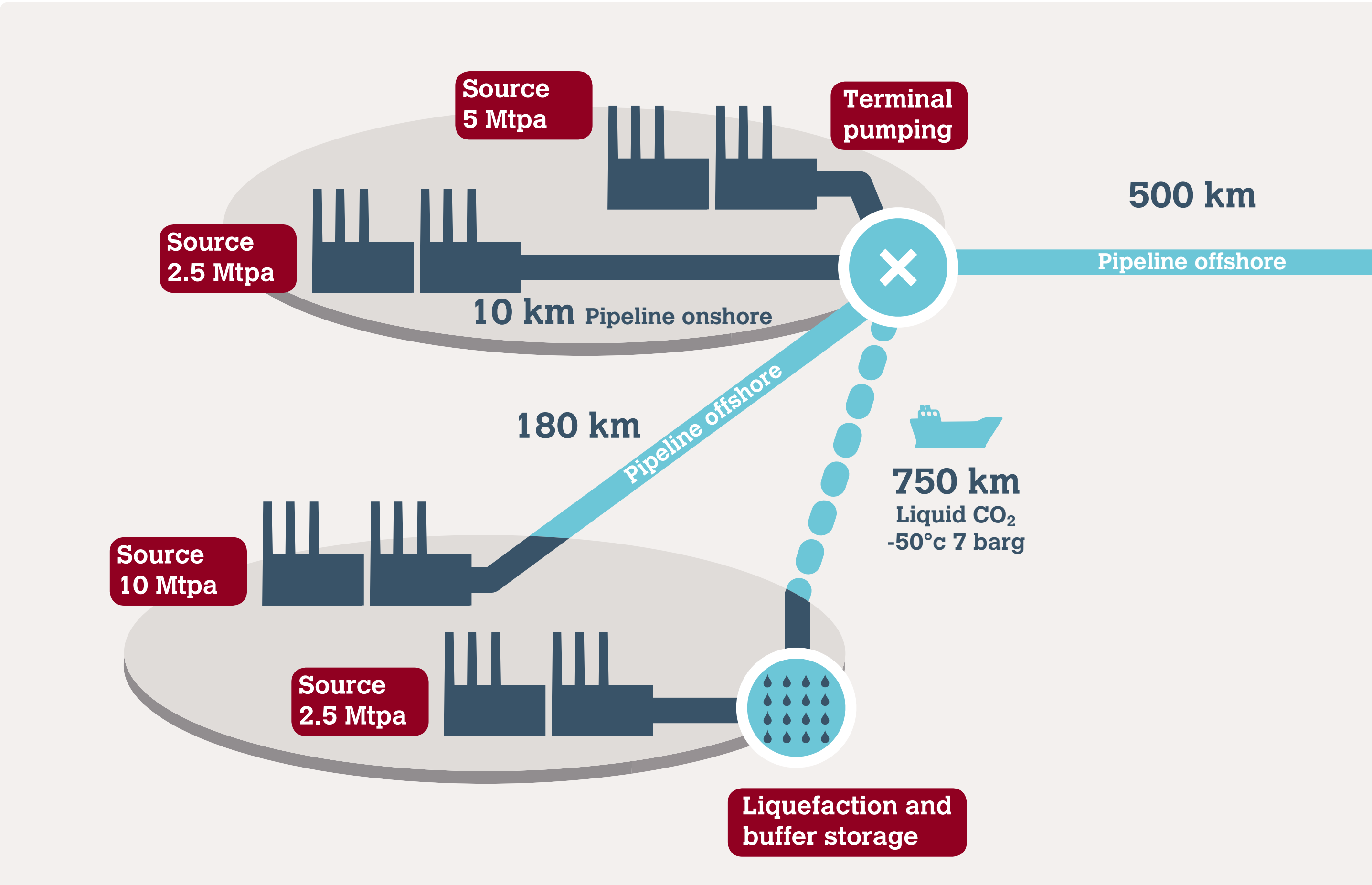
- The *transport process is assumed to deliver the CO_2 to the storage process at the well-head* in the following condition:
  - Temperature offshore: ambient seawater temperature, from 4°C to 15°C
  - Temperature onshore: ambient ground temperature ~10°C
  - Pressure: minimum 60 bar
  - Cost estimates for onshore pipelines assume that the pipeline terminates in a valve and a metering station, which constitute the interface to the storage process onshore.
  - Both offshore pipeline and ship transport cost estimates include the cost of a sub-sea well-head template, whereas manifold costs are assumed to be included in storage costs with the drilling of injection wells. The boundary towards storage is therefore at the sea bottom surface, below this template. For ship transport,

this implies conditioning (pumping and heating to the required condition) onboard for "slow" discharge directly to the well(s) without the use of intermediate buffer storage. A resulting assumption is that both the wells and storage reservoir are capable of receiving injection interrupted by shorter or longer periods, while waiting for the subsequent ship.

Several assumptions are also used in the reports in order to simplify the process and the calculations.

For further details, see individual reports on CO_2 capture, transport and storage.[14]

Figure 3: An offshore 20 Mtpa CO_2 transport network with an offshore pipeline spine of 500 km (used in this report)



[14] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html;
www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html;
www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

The results

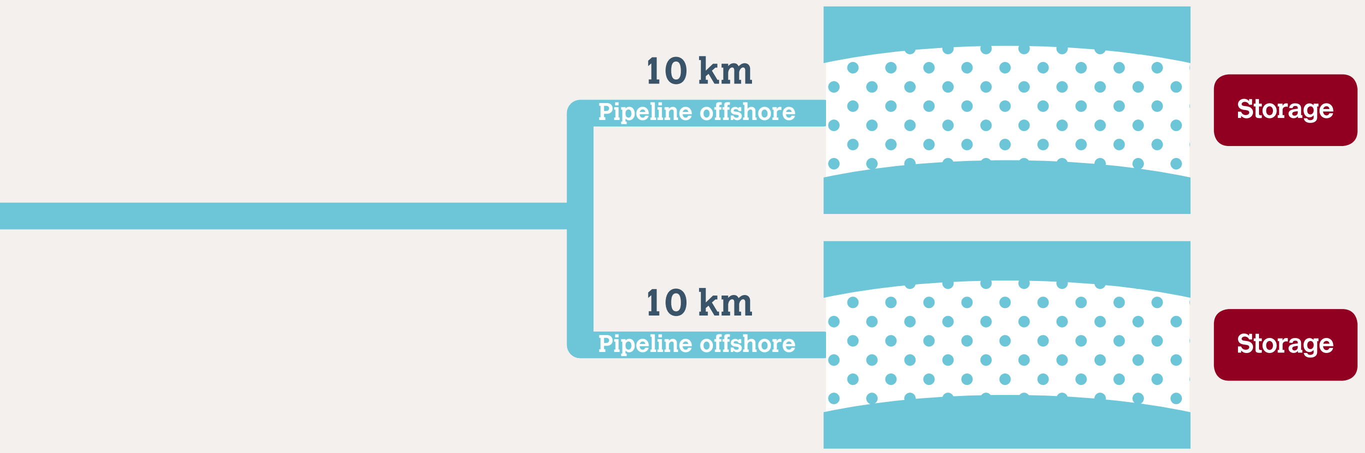
Integrated CCS projects

Costs for different CO_2 capture, transport and storage options were first determined, then combined in order to identify:

- *Total costs for full-scale commercial CCS projects in the EU post 2020.*
- *Key trends and issues for various deployment scenarios in the early commercial phase.*
- *The impact of fuel prices, economies of scale and other factors, e.g. economic.*

As each part of the CCS value chain includes multiple variants, the results provide a probable – but not complete – set of combinations.

N.B. Detailed data for the underlying cases for power plants and CO_2 capture, transport and storage are given in Table 6 in Annex I.



a) Single plant to a single "sink"

Early commercial power plants with CCS in Europe may be fired with coal or natural gas in the following scenarios:

- **Commercial hard coal-fired plants with CCS**. This case consists of 2 x 700 MW_{el} power plant blocks with CO_2 capture, together producing ~10 Mt CO_2 per year and a moderately favourable transport scenario, comprising a 10 km feeder + 180 km main pipeline to a deep saline aquifer (SA) onshore storage site.

- **Commercial natural gas-fired plants with CCS**. This case consists of 2 x 350 MW_{el} power plant blocks with CO_2 capture, together producing ~2 Mt CO_2 per year, which is reasonably close to the calculated costs for transporting 2.5 Mtpa used in the study. It also has a favourable transport scenario, comprising a 180 km onshore pipeline to an onshore SA storage site.

As large natural gas-fired CCGT plants can emit quantities of CO_2 comparable to CCS demonstration projects firing coal and lignite, they will therefore have similar transport and storage costs per tonne of CO_2.

b) Clusters of plants and sinks achieve economies of scale for CO_2 transport and storage

Wide-scale CCS deployment may well require the use of storage sites located further away from the power plant and the use of both on- *and* offshore storage sites. While costs for pipeline transport of CO_2 over long distances from a single plant to a single sink increase proportionally to the distance, clustering power plants to a local transport network results in economies of scale in both CO_2 transport and CO_2 storage in larger storage sites.

This is illustrated by calculating costs for a cluster arrangement consisting of natural gas and hard coal-fired power plants, utilising a common 500 km pipeline and a cluster of storage sites offshore:

- Two natural gas-fired plants – each with 2 x 350 MW_{el} power plant blocks with CO_2 capture – together producing ~2 Mt CO_2 per year per plant.

- One hard coal-fired plant – with 1 x 700 MW_{el} power plant block with CO_2 capture – producing ~5 Mt CO_2 per year.

- One hard coal-fired plant – with 2 x 700 MW_{el} power plant blocks with CO_2 capture – together producing ~10 Mt CO_2 per year.

The offshore 20 Mt/year CO_2 transport network[15] comprises (see Figure 3 above):

- A 5 Mt point source at the collecting point (one hard coal-fired plant, with 1 x power plant block with CO_2 capture).

- 2.5 Mt (from one natural gas-fired plant, with 2 x power plant blocks with CO_2 capture), transported to the collecting point via a 10 km onshore pipeline.

- Another 2.5 Mt CO_2 (from the other natural gas-fired plant, also with 2 x power plant blocks with CO_2 capture), transported 750 km by ship to the hub.

- A final 10 Mt CO_2 (from one hard coal-fired plant, with two power plant blocks with CO_2 capture), transported 180 km offshore by pipeline.

From the hub, 20 Mt CO_2 is transported in an offshore pipeline (500 km) and finally distributed to the storage sites – SA or DOGF – via two 10 km pipelines, each carrying 10 Mt CO_2.

[15] Further described in the CO_2 Transport Cost Report, as Network # 8b

c) The costs of CCS for various deployment scenarios

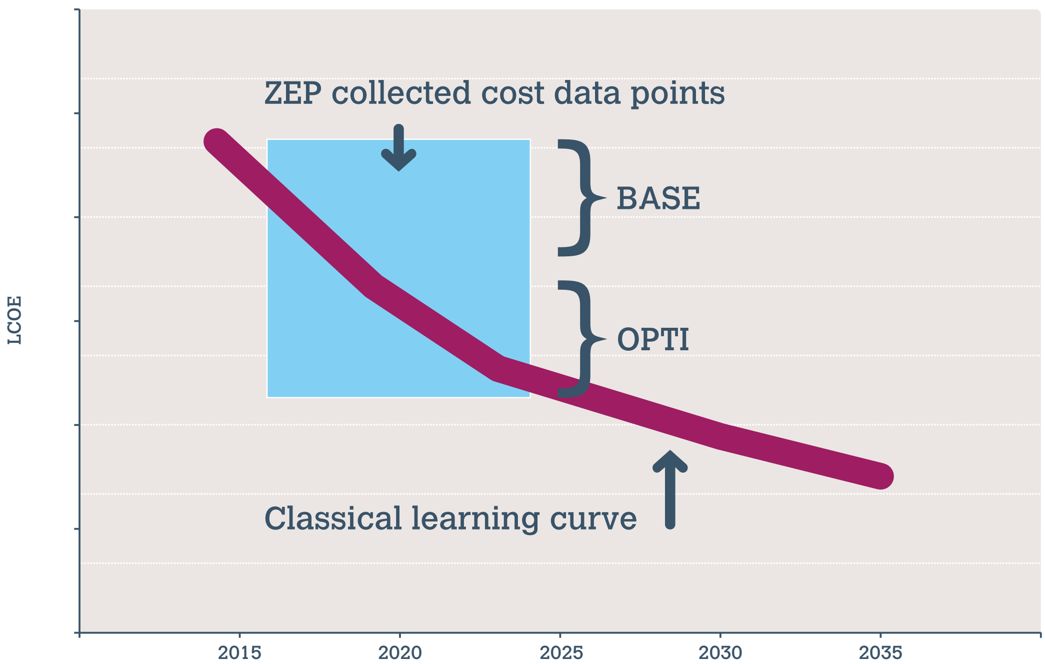
For each capture technology, two sets of costs were developed for new-build power plants with CO_2 capture: a base plant (BASE) represents an early, more conservative plant design with higher costs; an optimised plant (OPTI) represents a design based on first commercial experience – including technology improvements, refined solutions and improved integration – but still using the three main capture technologies (see also page 11).

No precise date can be attached to the raw data points collected from ZEP contributors. As illustrated in Figure 4, they are representative of costs estimated in 2009/2010 for a commercial plant whose Final Investment Decision is taken between 2015 and 2025. The data were normalised through a common cost calculation template, ensuring that the resulting numbers would be grounded into a defined set of assumptions. The highest cost numbers correspond to the BASE plant definition and have been normalised and averaged, while the lowest numbers correspond to OPTI plants, based on first commercial experience.

This approach is not based on a classical industrial learning curve approach, but constructed from the anonymous collection of the various contributions from ZEP members, each with their own views on the learning curve. However, ZEP believes that the cost boundaries between BASE and OPTI represent the most accurate view to date on the expected cost span for first commercial plants to be commissioned post 2020. (Several studies exist describing the potential of cost reduction for CCS as a result of the learning process, such as from Edward Rubin at Carnegie Mellon University.[16])

For the integrated CCS cases described below, average expected costs for OPTI plants have been used, since it is considered that the majority of commercial CCS projects will be based on OPTI plant designs, rather than the more expensive BASE designs. Low, Medium/Base and High cost assumptions are used for CO_2 storage. For detailed data for power plant concepts with CO_2 capture and CO_2 storage cost assumptions, see Table 6 in Annex 1.

Figure 4: An illustration of ZEP data collected for base (BASE) and optimised (OPTI) power plants with CO_2 capture (post-combustion, IGCC with pre-combustion and oxy-fuel)



[16] www.cmu.edu/epp/iecm/IECM_Publications/2007a%20Rubin%20et%20al,%20Intl%20Jour%20of%20GHG%20(Feb).pdf

Figure 5: Total LCOE for integrated CCS projects vs. reference plants without CCS (including various assumed costs for EUAs under the EU ETS and using Middle fuel costs)

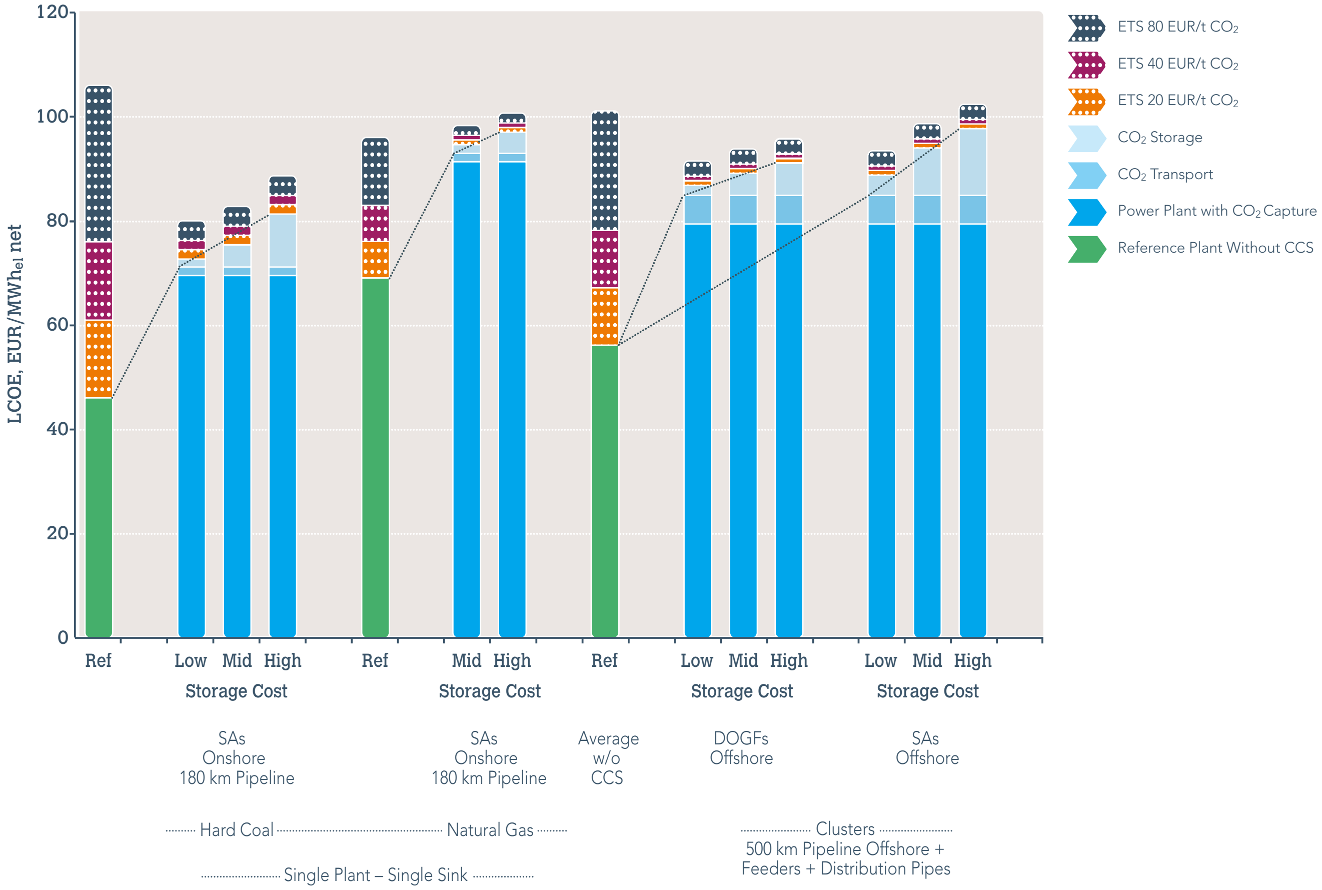


Figure 5 shows the calculated LCOE for various cases, with the green bars representing the reference plants for each case. The blue bars represent the Single Plant hard coal and natural gas CCS power plants to the left and a Cluster of plants to the right. On top of each bar, transport and storage costs are added, while the striped colours show EUA costs for different price levels. The dotted lines highlight the LCOE for each CCS case (excluding any costs for EUAs) vs. reference cases without CCS.

- The combined cost of the power plant with capture accounts for the majority of total costs.
- Based on study assumptions, coal-fired power plants will primarily be fitted with CCS, since they are more competitive if EUA costs are high enough.

While Figure 5 shows total LCOE for integrated CCS projects vs. reference plants without CCS (including various assumed costs for EUAs) using *Middle fuel* costs, Table 4 (page 40) and Figure 11 (page 23) show the *ranges* of LCOE for power plants with CCS resulting from uncertainties and variations in CO_2 capture, transport and storage costs.

Other calculations may also be made from Figure 5, such as the CO_2 avoidance costs and the additional cost of CCS for generated electricity. This is illustrated in Figures 6-10.

Figure 6 shows costs per tonne of CO_2 captured for integrated CCS projects (hard coal and natural gas) calculated with Low, Middle and High Fuel Costs. Transport and Storage costs are also added (Single Source – Single Sink).

From Figure 6 we can conclude that:

- CO_2 capture costs per tonne for the natural gas-fired Single Plant case are much higher than for the hard coal-fired Single Plant case, due to the higher fuel price and the lower CO_2 concentrations in gas turbine exhaust gases than in boiler flue gases (requiring larger absorbers for the same quantities of CO_2).

- The impact of the fuel price on the total cost per tonne of CO_2 captured is higher for gas than for coal.

- When calculated on a *per tonne basis*, the CO_2 transport and storage is more expensive for gas than for coal, since smaller quantities give higher specific costs. Total cost per kWh, on the other hand, is lower for gas, since it produces less than half the amount of CO_2 (see also Figure 7).

Figure 7 shows additional LCOE for integrated CCS projects (hard coal and natural gas) vs. reference plants without CCS (Single Plant – Single Sink). Calculations are made for Low, Middle and High fuel costs (excluding any saved costs for EUAs).

From Figure 7 we can conclude that:

- Total additional LCOE is higher for the hard coal case than for the natural gas case for all fuel cost scenarios.

- The additional LCOE for CO_2 capture is mildly dependent on fuel price. The LCOE for natural gas compared to hard coal is around the same for the Middle fuel cost; lower for the Low fuel cost; and higher for the High fuel cost.

- The additional LCOE for CO_2 transport and storage is lower for the natural gas case than for the hard coal case.

If only transport and storage costs are calculated, Figures 8 and 9 can be created, where Clusters are also included. These give cost elements for the different cases and show that:

- Single Source – Single Sink cases do not give high transport costs because shorter distances are assumed than for a larger Cluster.

- SA are always more expensive than DOGF.

- Storage costs are higher for coal than for gas when calculated as LCOE, but lower per tonne of CO_2.

Figure 6: Costs per tonne of CO_2 captured for integrated CCS projects (hard coal and natural gas) calculated with Low, Middle and High Fuel costs. Transport and Storage costs are also added (Single Source – Single Sink)

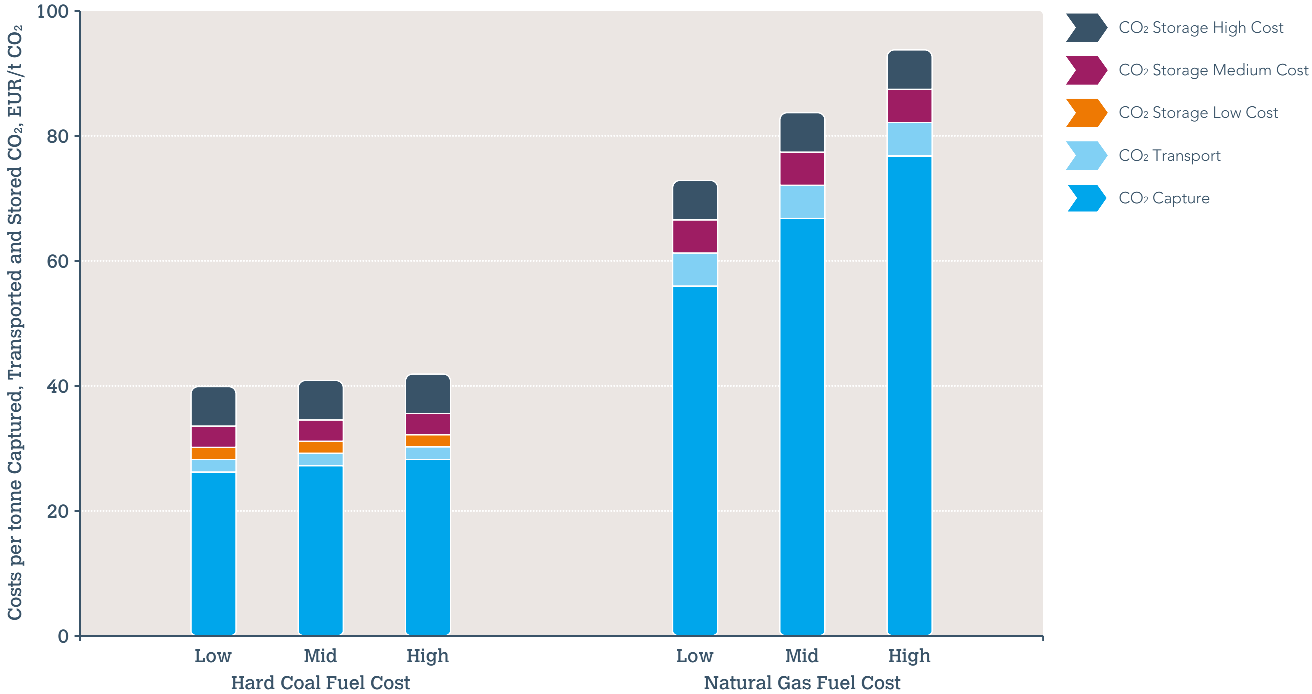


Figure 7: Additional LCOE for integrated CCS projects (hard coal and natural gas) vs. reference plants without CCS (Single Plant – Single Sink). Calculations are made for Low, Middle and High fuel costs (excluding any saved costs for EUAs)

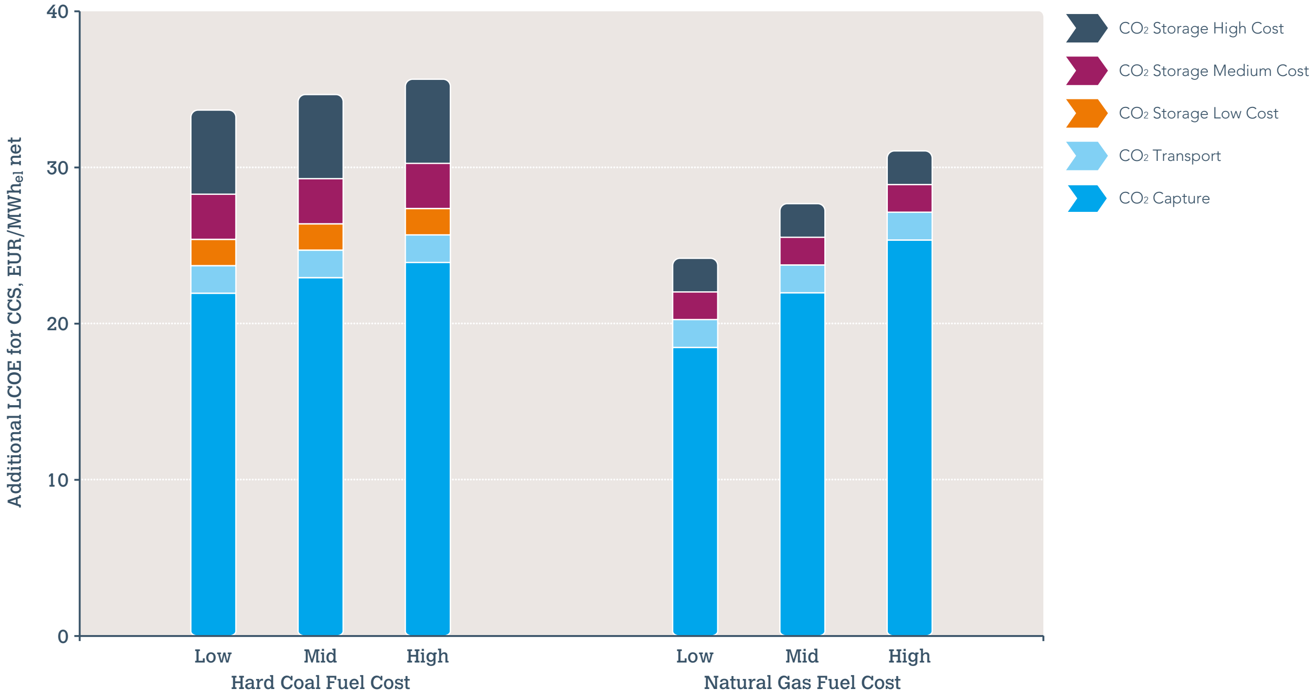


Figure 8: Calculated costs per tonne of CO_2 captured for transport and storage for integrated projects. For the Clusters, the use of SA and DOGF are highlighted

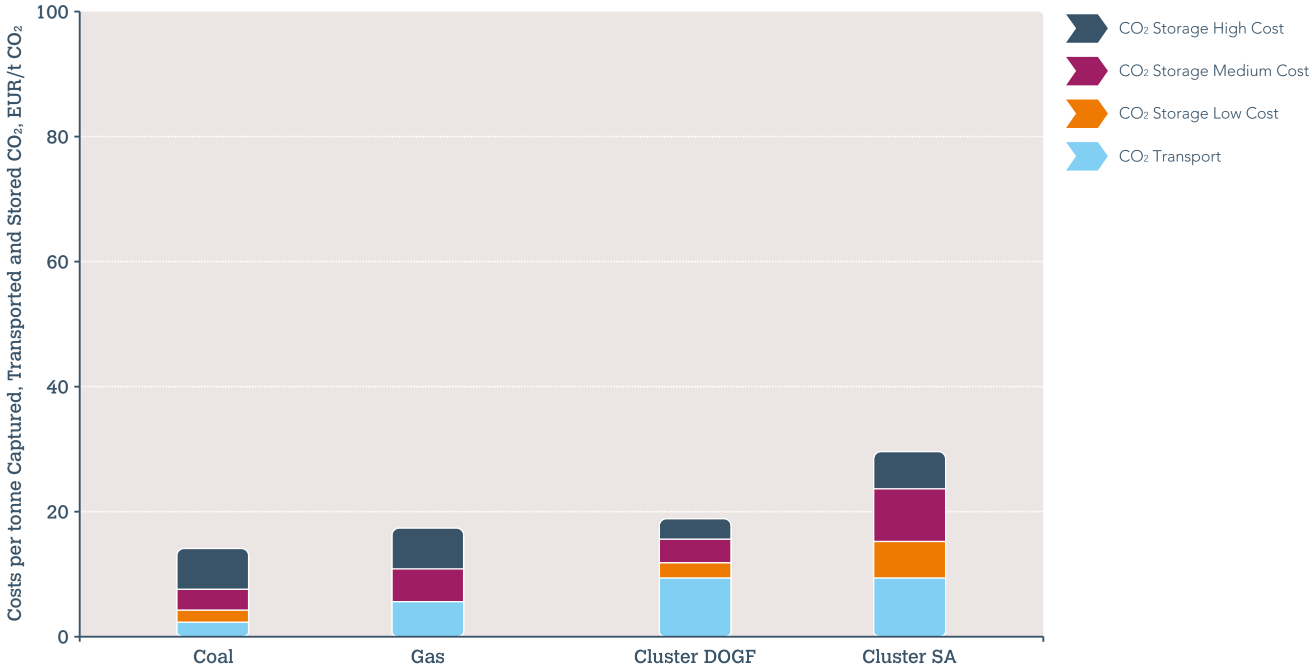


Figure 9: Calculated costs as LCOE for transport and storage for integrated projects. For the Clusters, the use of SA and DOGF are highlighted.

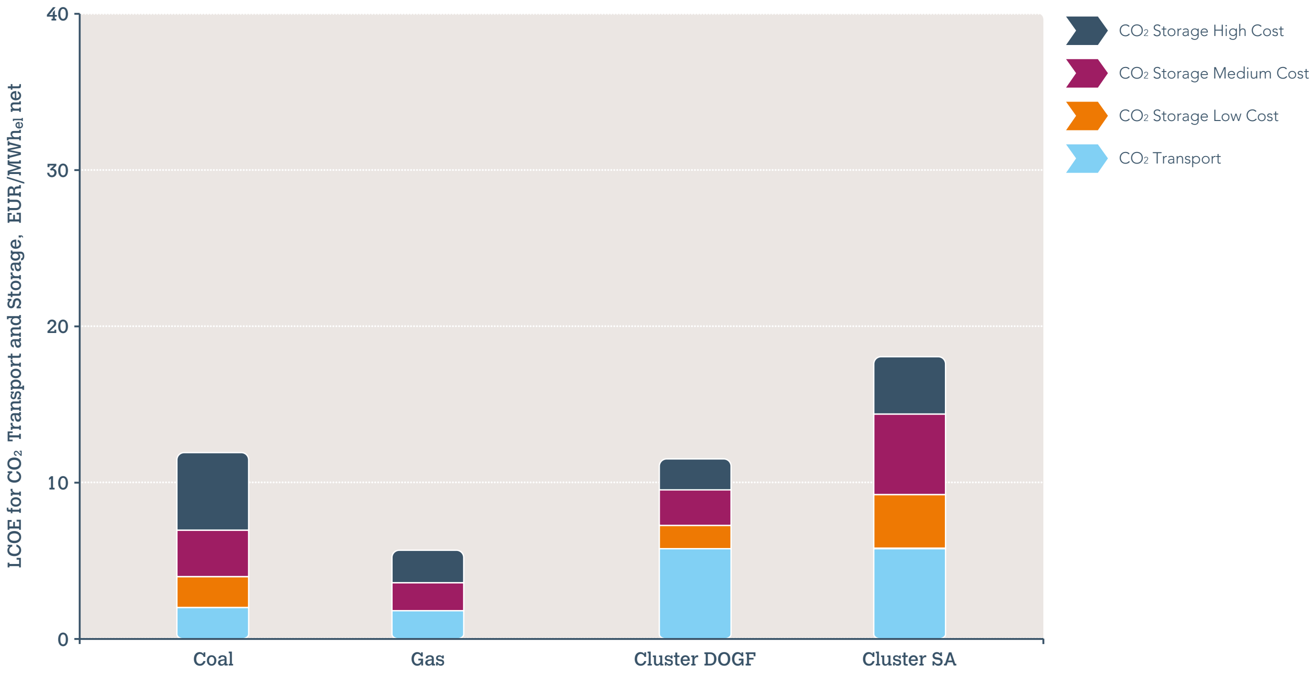


Figure 10: Total CO_2 avoidance costs for integrated CCS projects – the price of EUAs required to justify building CCS projects vs. a plant without CCS from a purely economic point of view.

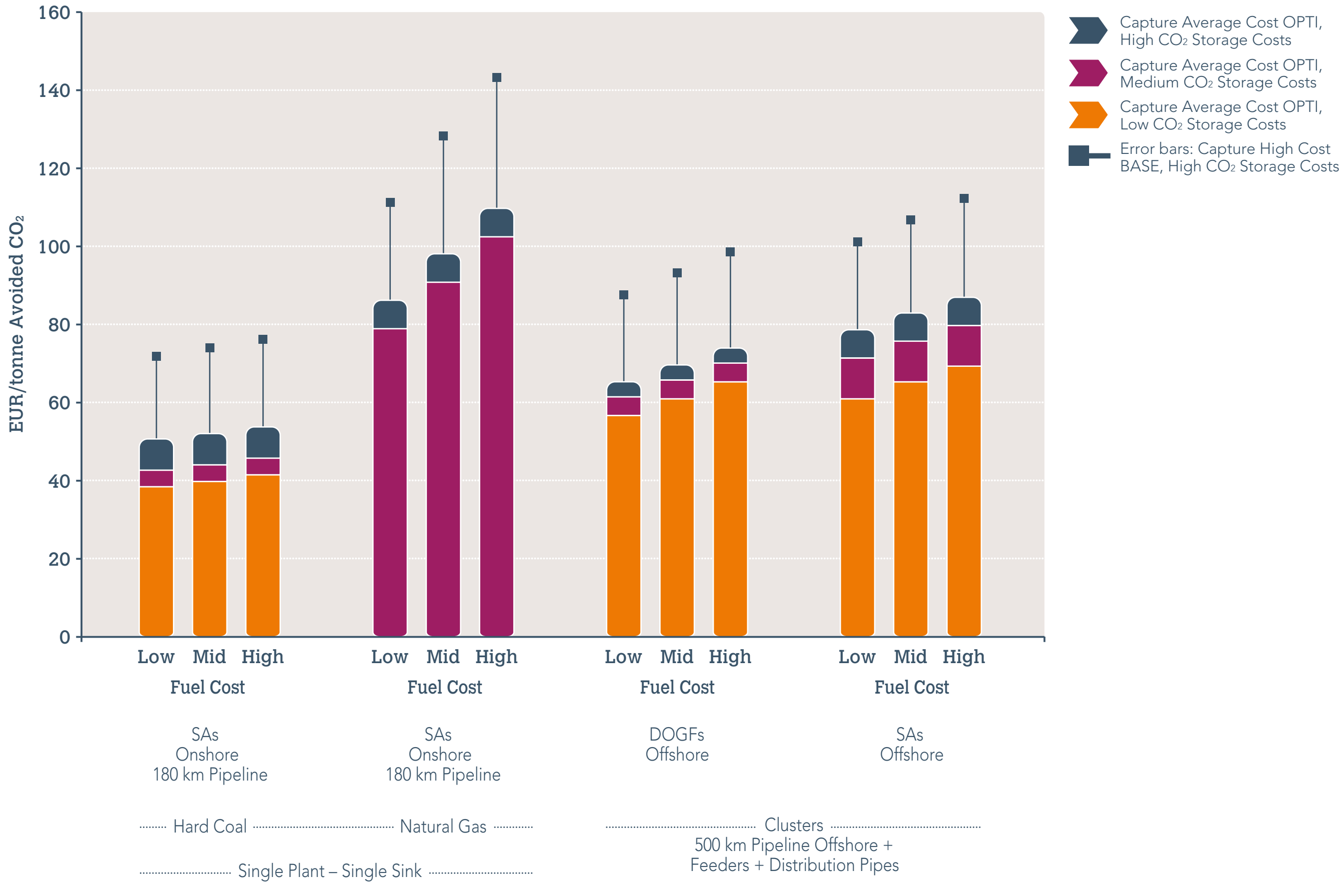


Figure 10 shows CO_2 avoidance costs for the integrated cases. This mirrors the EUA price and shows how high it must rise before it is more feasible to build a power plant with CCS than a corresponding reference plant without. If the higher cost for a BASE plant with CO_2 capture is also combined with the high CO_2 storage cost assumptions, the resulting total avoidance cost rise is illustrated by the error bars.

- For the hard coal Single Plant – Single Sink case, CO_2 avoidance costs are €40-50/t CO_2 (mainly dependent on the level of CO_2 storage costs), while those for natural gas are much higher and strongly dependent on fuel prices. It will therefore be cheaper to build natural gas-fired plants without CCS and pay for EUAs, than to build them with CCS for EUA prices lower than €80-110/t CO_2.
- For the Cluster with storage in offshore DOGF, CO_2 avoidance costs are €55-70/t CO_2 due to its mix of natural gas- and coal-fired plants. The difference between using a Low and High fuel cost equates to a range of ~€10/t CO_2. For storage in offshore SA, CO_2 avoidance costs increase by €5-15/t CO_2 over the DOGF case.
- If the same transport network and storage system (DOGF) is applied to a Cluster consisting only of hard coal-fired plants, CO_2 avoidance costs are €45-60/t CO_2.

d) Impact of fuel prices on costs

As fuel price is one factor which will influence the deployment of CCS considerably, it is important to disseminate the results for varying prices (Figure 11).

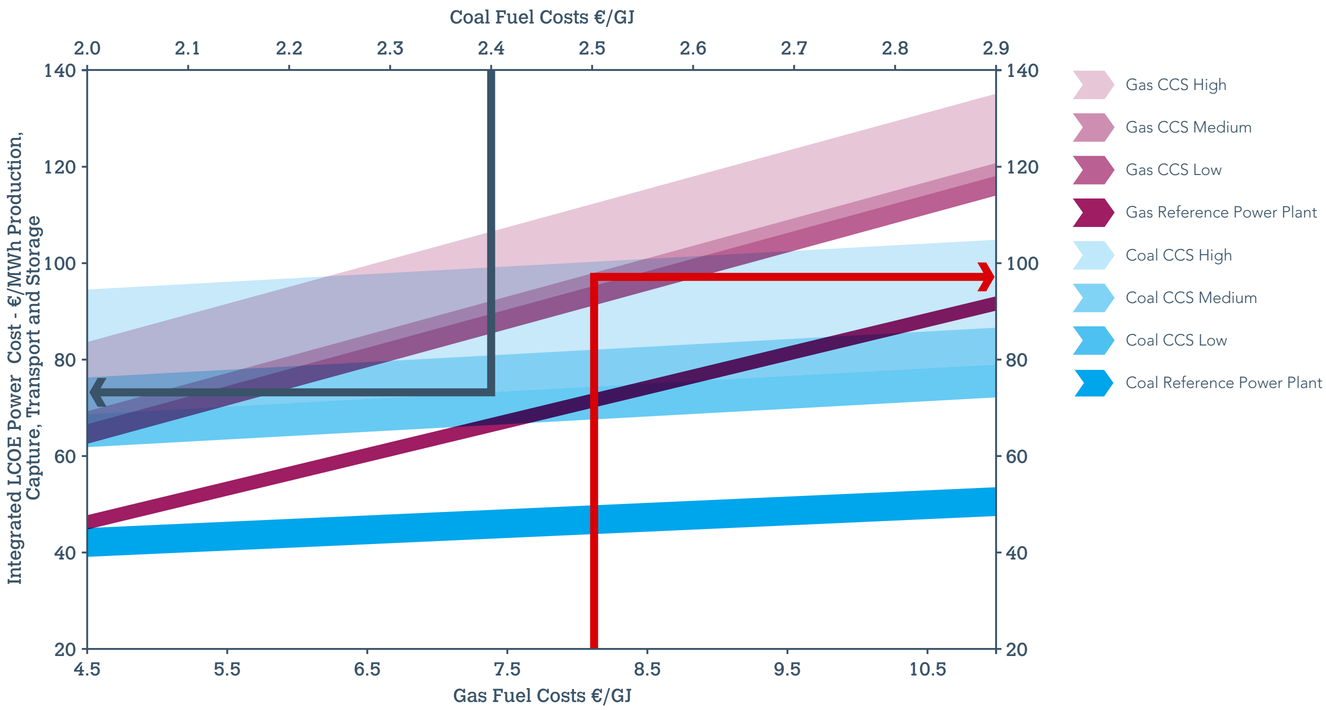
N.B. Figure 16 on page 29 shows the impact of fuel prices on CO_2 capture costs; Figure 11 below includes the entire CCS value chain.

Figure 11 describes the LCOE for the reference plants (lower curves) and the CCS plants as a function of fuel prices. The figure actually contains two diagrams: the upper horizontal axis shows the coal prices, while the lower axis shows the gas prices with the fuel price ranges used in this study.

N.B. These two prices do not have a fixed relation to each other, as may be the impression given by the diagram.

In this study, the Middle fuel cost for coal is €2.4/GJ; €8.0/GJ for gas. These two assumptions are illustrated as solid blue (for coal) and red (for gas) lines in the diagram.

Figure 11: LCOE ranges for Single Plant – Single Sink cases vs. reference plants without CCS, using the fuel cost ranges used in the study (excluding any EUA costs).



The LCOEs cover the ranges from Low OPTI CO_2 capture costs combined with Low CO_2 storage cost assumptions, up to High BASE CO_2 capture costs combined with High CO_2 storage cost assumptions. Natural gas LCOEs are strongly dependent on the fuel costs. As no low OPTI data were provided for natural gas, they have been estimated to be €5/MWh lower than for the reported OPTI data.

- For the hard coal-fired, Single Plant – Single Sink case, CCS increases the LCOE from €40-50/MWh (excluding any EUA costs) to €70-90/MWh. (This does depend somewhat on the fuel cost (here €2-3/GJ) and cost levels for CO_2 storage).
- For the natural gas CCGT power plant with CCS, the final result is heavily dependent on the fuel cost (here €4.5-11/GJ). For natural gas prices lower than ~€6/GJ, the LCOE is competitive with the hard coal Middle fuel cost-based cases. This is a little higher than when only the capture cost was calculated (Figure 16).

For clarity, two tables with basic data for the integrated CCS projects are included in Annex 1: Table 4 shows all data for the LCOE calculations, while the amount of investment that will have to be made is illustrated by the CAPEX shown in Table 5.

e) CCS: a cost-effective source of low-carbon power

This study has assumed that all power plants will operate in base load since:

a) A CCS power plant will be dispatched before any unabated fossil fuelled power plant as the variable costs will be considerably lower (taking EUA prices into account).

b) A CCS power plant investment will need forecasted base-load utilisation as LCOE costs have a high dependency on plant load factor – especially for coal.

Figure 12: The LCOE of integrated CCS projects (blue bars) compared to the reference plants without CCS (green bars)

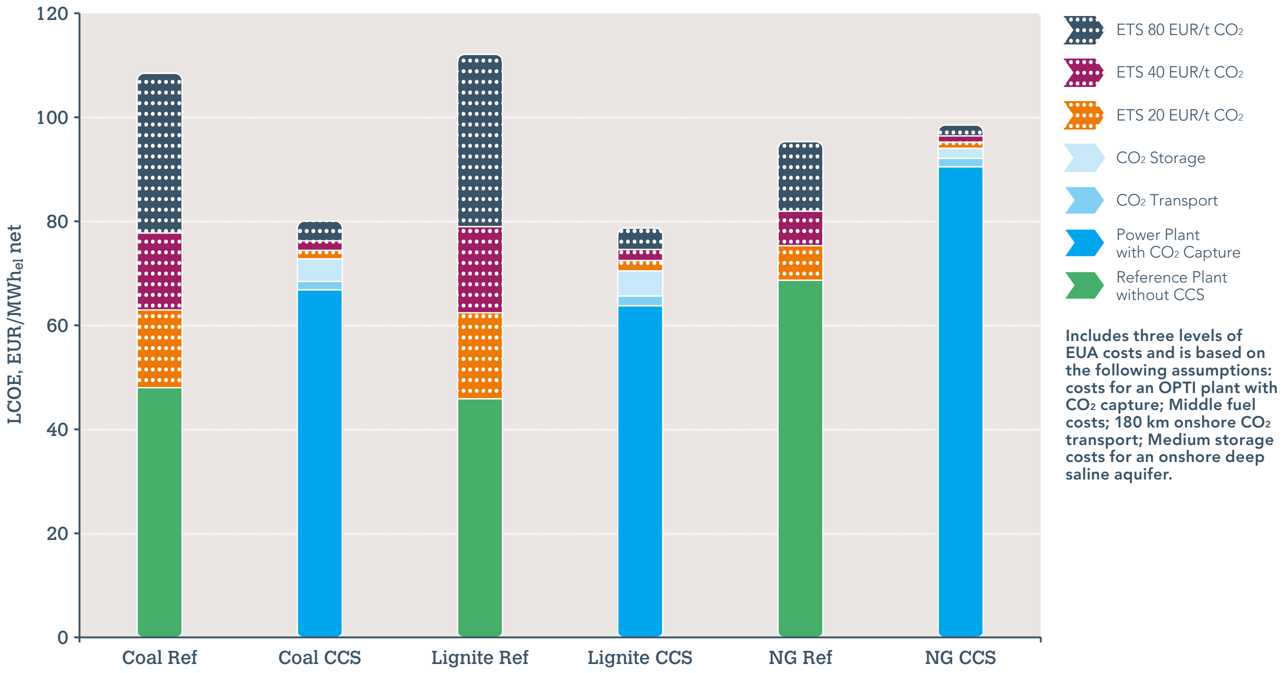


Figure 12 shows estimated LCOE for an OPTI power plant with CCS, including three levels of EUA costs, and is based on the following assumptions:

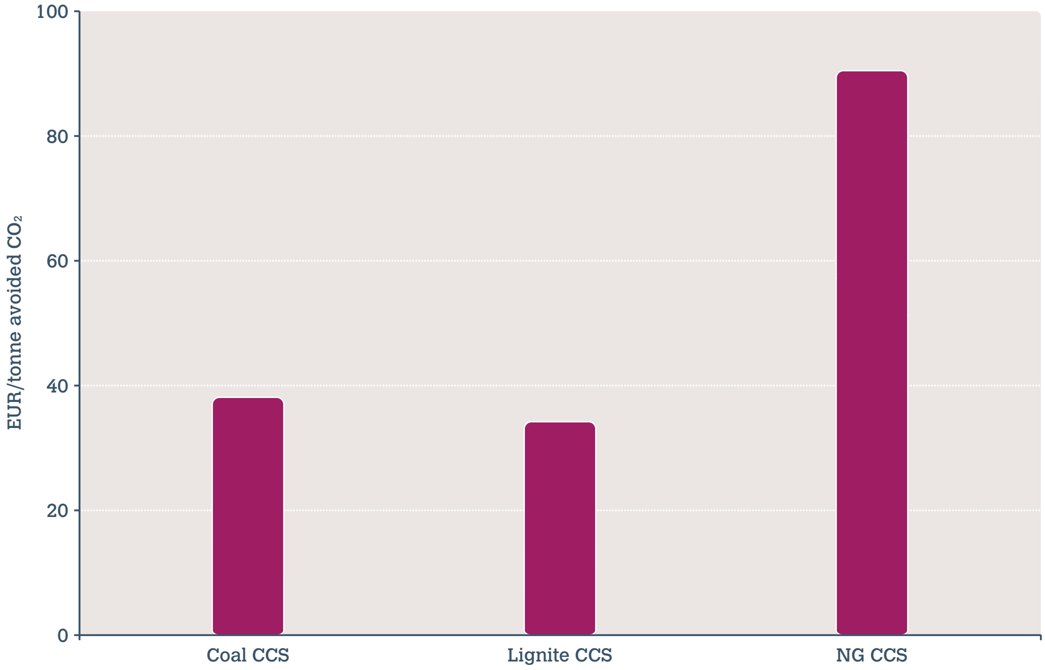
- *Costs for a OPTI power plant with CO_2 capture*
- *Middle fuel costs*
- *180 km onshore CO_2 transport*
- *Medium storage costs for an onshore SA.*

- The two coal cases are similar in cost, while the gas case shows a higher cost. At lower EUA prices, the coal cases with CCS also come out more favourably than the gas case when compared to the reference plants.

- The blue bars show that the combined cost of the power plant with capture comprises 80-90% of the total LCOE (~75% of the additional LCOE for CCS vs. the reference plants). However, transport and storage are a vital part of the CCS value chain and to a large extent determine the location and decision to proceed with a project. The need to obtain permits and public support must also be taken into account.

- The corresponding avoidance costs for CCS, compared to the reference plants with the same fuel, are shown in Figure 13 below.

Figure 13: CO_2 avoidance costs for possible plants commissioned in the mid 2020s – the price of EUAs required to justify building CCS projects vs. a plant without CCS from a purely economic point of view (calculated on the same basis as Figure 12)



- The associated EUA break-even cost would correspond to a price of ~€37/tonne of CO_2 for hard coal; ~€34/tonne of CO_2 for lignite; ~€90/ tonne of CO_2 for gas.

- At an EUA price of €35/tonne[17] of CO_2, these full-size, coal-fired CCS power plants are therefore close to becoming commercial and competitive with coal-fired power plants without CCS, while the gas case is not. However, unabated gas power plants remain a commercial option with the assumptions made, as can be seen in Figure 12.

N.B. Costs for OPTI plants assume a completely successful demonstration of the technology and/or that the first full-size CCS plants (following the EU CCS demonstration programme) have already been in operation. All reported costs exclude the exceptional development and other costs associated with the demonstration programme itself.

There is a small but noticeable difference between Figures 5-10 and Figures 12 and 13. While the latter use lowest-cost capture technology, Figures 5-10 use a mean value for the three different technologies. When we compare selected cases, primarily the best capture technology will be chosen in each case. Figures 5-10 also do not include any lignite cases as this would complicate the figures significantly. However, as Figures 12 and 13 do not include any variations for storage, fuel or transport costs, lignite can be included.

[17] This is in accordance with EU estimates of EUA prices for 2025: http://ec.europa.eu/clima/documentation/roadmap/docs/sec_2011_288_en.pdf

f) Co-firing with biomass

Biomass is a more expensive fuel than coal (calculated per energy unit), and at current EUA prices and without support regimes, increases the price of CCS if it is used for co-combustion.

Under the ETS Directive, biomass combustion has a zero emission factor. In order to incentivise biomass combustion for CCS, a negative emission factor for such use of biomass is therefore necessary in order to create a level playing field between renewable and fossil fuel-based CCS. This can be achieved through project-specific applications to the European Commission, which has signalled that it would welcome such requests from Member States.

The break-even point for the commercial viability of CCS and biomass co-combustion would then be an EUA price of ~€50/tonne of CO_2, at today's relative fuel costs for coal and biomass in Northern Europe. This evaluation is not addressed in this study, but will be covered in future updates.

CO_2 Capture

ZEP has calculated the LCOE and CO_2 avoidance costs for power plants commissioned in the early 2020s, located at a generic greenfield site in Northern Europe. The aim: to establish the perceived "real" investment, O&M costs for the first, state-of-the-art commercial power plants with CO_2 capture in Europe. Costs for CO_2 capture include the capture process, plus the conditioning and compression/liquefaction of the captured CO_2 required for transport.

N.B. Cost estimates do not include any additional site-specific investments. Costs for power plants with first-generation CO_2 capture technologies are calculated for High, Middle and Low fuel costs respectively. See page 17 for a description of BASE and OPTI power plants with capture.

Figure 14 shows that for hard coal-fired power plants based on second-quarter 2009 equipment cost levels, a fuel cost of €2.4/GJ and 7,500 equivalent full-load operating hours, the addition of CO_2 capture and the processing of the CO_2 for transport is estimated to increase the LCOE from ~€48/MWh to €60-70/MWh, depending on the capture technology for a new-build OPTI power plant design. (Costs for the first (BASE) plants are higher, as anticipated.)

Corresponding CO_2 avoidance costs range from €30-35/t CO_2, as shown in Figure 15 below.

Figure 14: The LCOE for hard coal-fired power plants with CO_2 capture (using Middle fuel costs)

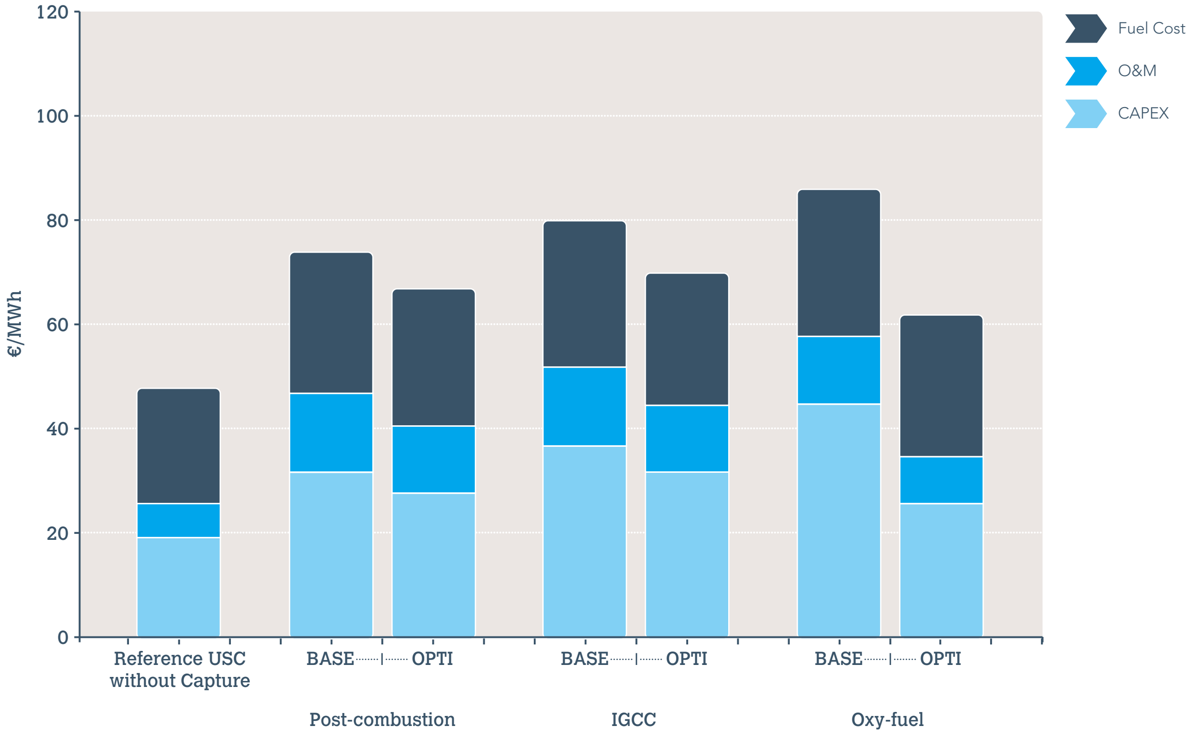
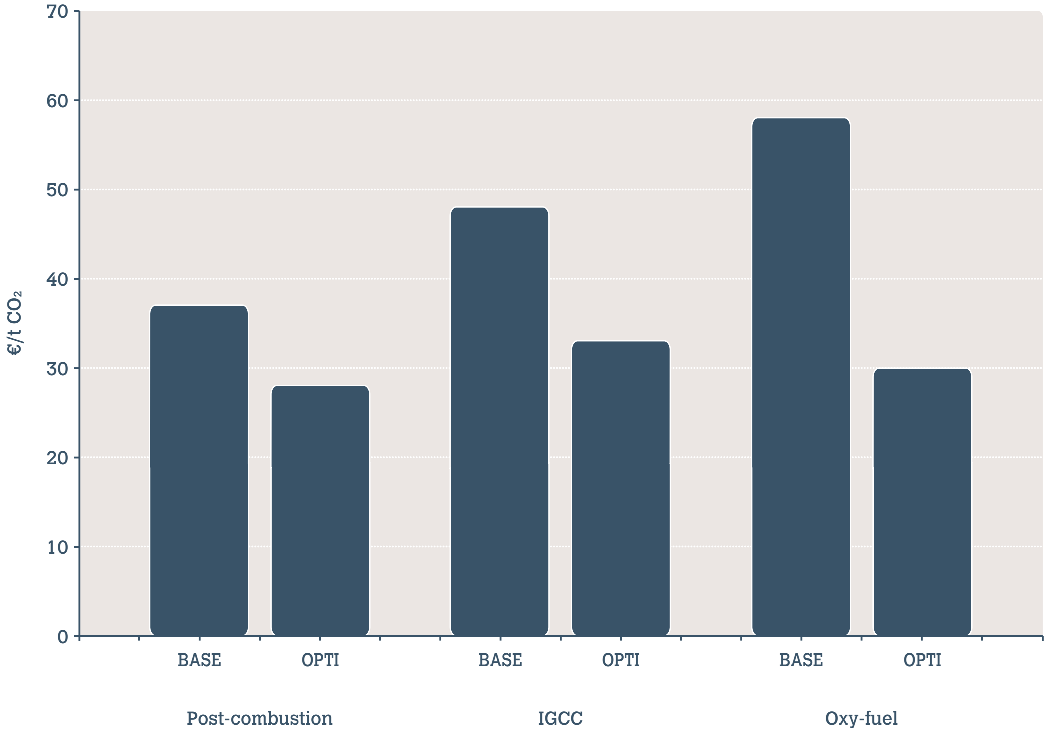


Figure 15: CO_2 avoidance costs for hard coal-fired power plants with CO_2 capture



Studies have also been undertaken for lignite-fired power plants with CO_2 capture that imply that a CO_2 avoidance cost in the range of €30/t CO_2 is possible for an OPTI advanced power plant with CO_2 capture and pre-drying of the lignite.

As anticipated, an analysis of *natural gas* CCGT power plants with post-combustion capture shows a heavy dependence of fuel costs on the final result, as can be observed in Figure 16 for an OPTI power plant.

At the lower end of the cost range of natural gas, CO_2 avoidance costs are still more than double those of a hard coal-fired power plant, but due in part to the lower quantities of CO_2 to be captured, the LCOE is competitive with other fuel sources, being ~€65/MWh for a natural gas price slightly under €5/GJ (see Figure 16).

Availability may slightly differ for the different capture technologies and the development of renewable power may also limit the plant's operational time in the future. However, the achievement of high plant availability must be a key objective of the EU CCS demonstration programme so that costs remain competitive. This is especially important for pre-combustion capture, as the IGCC power plant design contains a considerably larger number of components and is not a common technology within the power industry.

Nevertheless, a CCS plant will always be dispatched before any other fossil-fuelled power plant, due to the lower variable operating costs (when EUA prices are taken into account). An unabated plant, on the other hand, will suffer from the cost of EUAs.

In order to illustrate the impact of availability for hard coal-fired power plants with CO_2 capture, a calculation of the generation costs has been made as a function of equivalent operating hours (Figure 17, pages 29-30).

Figure 16: LCOE and CO_2 avoidance costs for natural gas-fired power plants with CO_2 capture are heavily dependent on the fuel cost. The vertical blue lines for €4.5, €8 and €11/GJ represent the Low, Middle and High cases used for gas fuel cost.

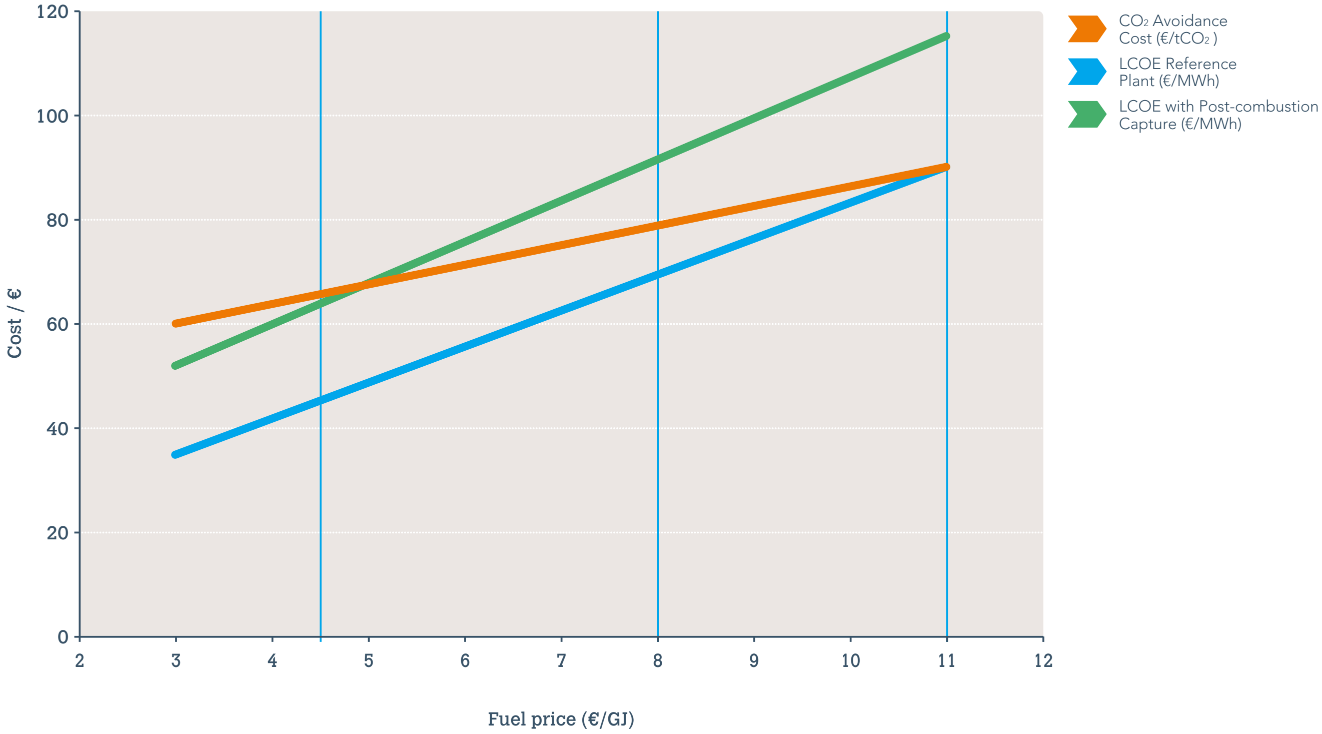
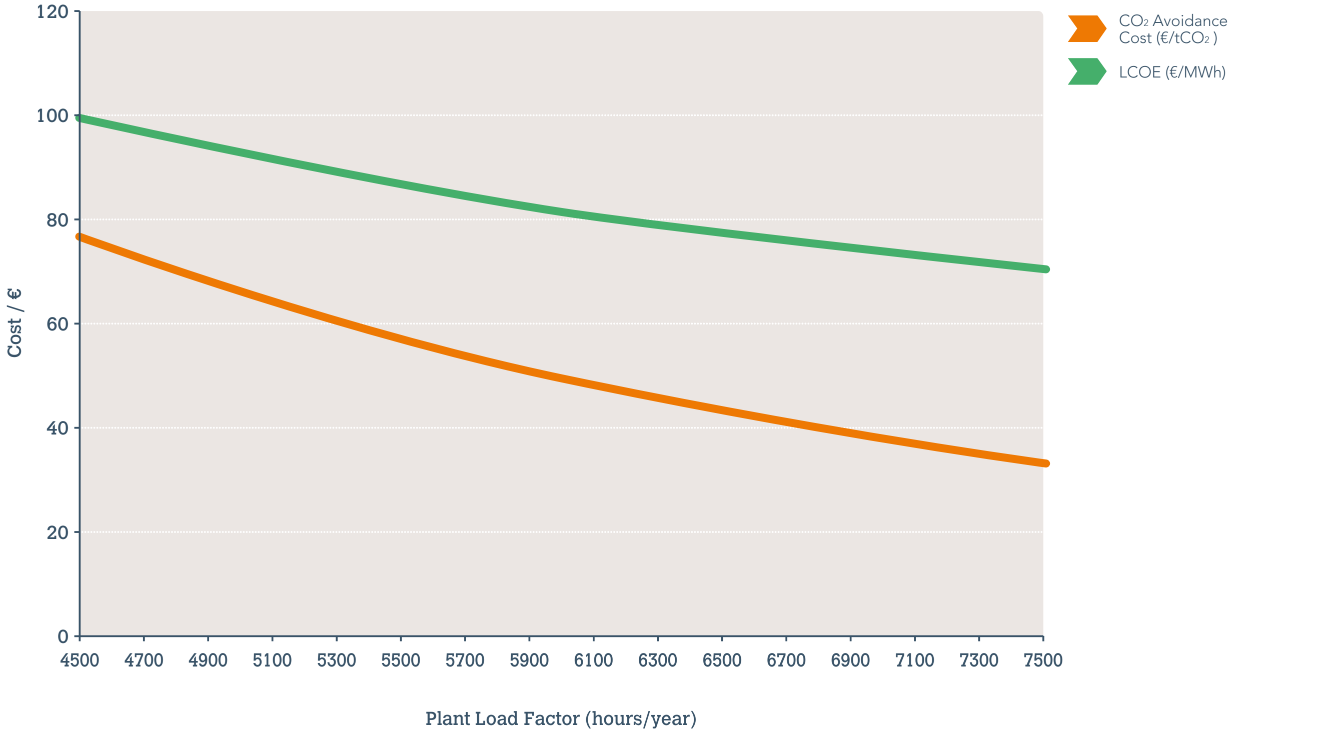
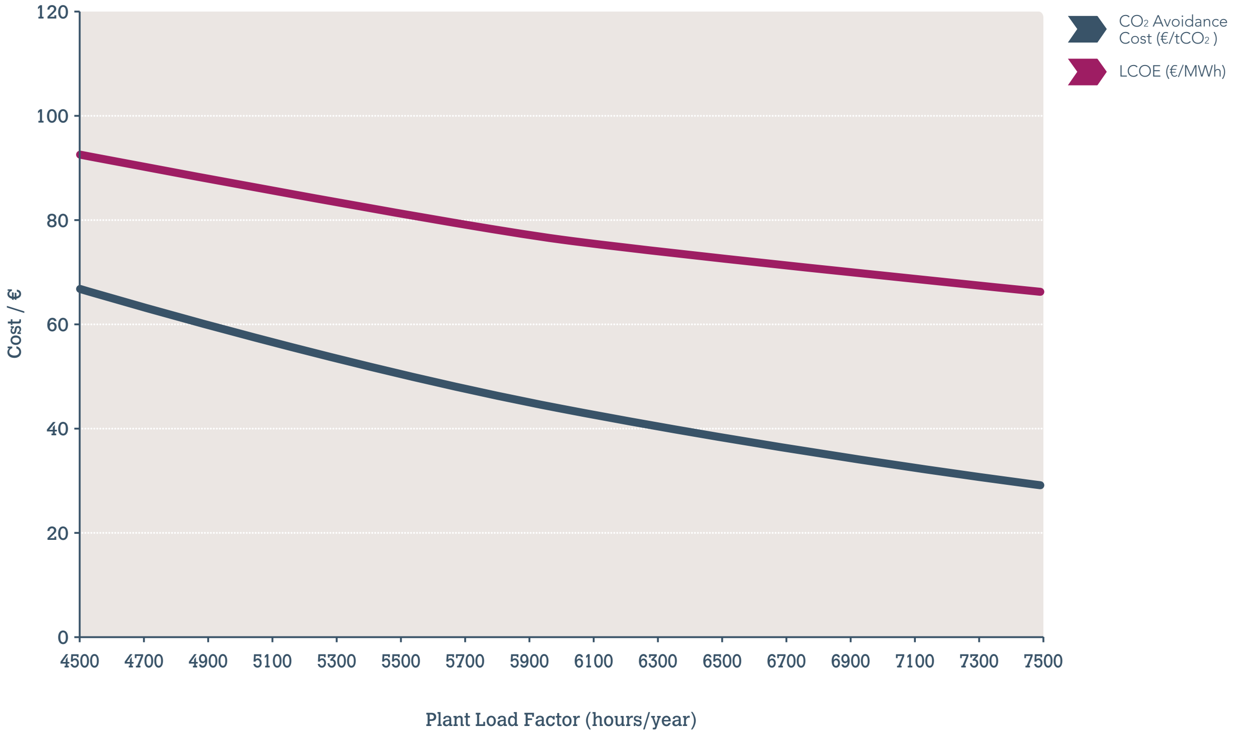


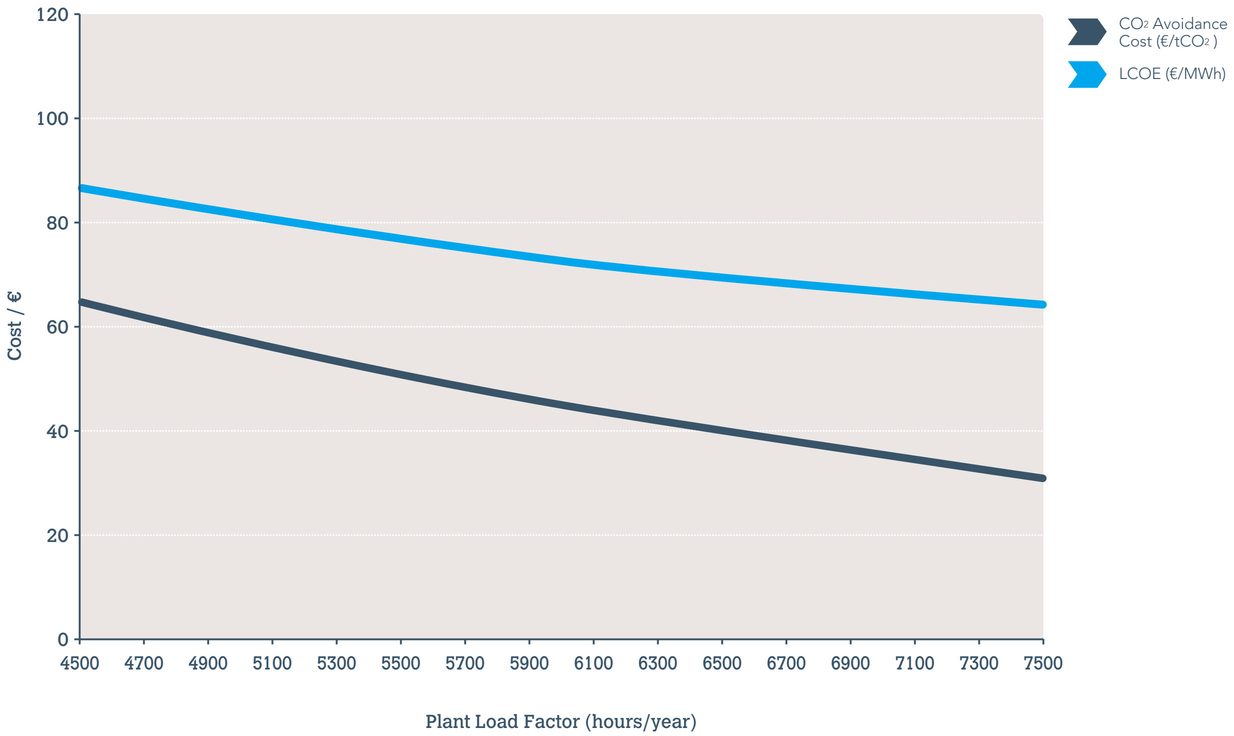
Figure 17: Dependence on Plant Load Factor for all three coal technologies, based on OPTI plants. Reference power plant load is kept at 7,500 hours per year for the calculation of CO_2 avoidance costs. Achieving high plant availability is key to keeping costs competitive.



Hard coal IGCC power plants with pre-combustion capture



Hard coal-fired power plants with post-combustion capture



Hard coal-fired power plants with oxy-fuel

Analysis of other CO_2 capture cost studies

The costs obtained in this study cannot directly be compared to other previously published studies as the boundary conditions tend to be different, which impacts on the final result. However, a simple comparison has been made by extracting the technical and economic data from other studies and recalculating the costs with the boundary conditions of this study. This shows that as CO_2 avoidance costs are higher for less efficient sub-critical steam power plants, state-of-the-art ultra supercritical steam conditions need to be considered as standard for new-build European power plants (which may in the future be retrofitted with CCS, as well as built directly with CCS).

The LCOE and CO_2 avoidance costs calculated in this study are also higher than those of previous European cost studies[18] due to a better current understanding of the capture processes. However, they tend to be slightly lower than the majority of other recent international studies.[19]

For full details of underlying assumptions and cost calculations, see the individual report on CO_2 capture: www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html.

[18] E.g. “EU Demonstration Programme for CO_2 Capture and Storage (CCS): ZEP’s Proposal”, November 2008; ENCAP: “Power systems evaluation and benchmarking. Public Version”, February 2009

[19] E.g. Global CCS Institute: “Strategic Analysis of the Global Status of Carbon Capture and Storage: Report 2 Economic Assessment of Carbon Capture and Storage Technologies”, 2009; NETL: “Cost and Performance Baseline for Fossil Energy Plants”, DOE/NETL-2007/1281, August 2007

CO_2 Transport

This study describes the two major methods of transportation – pipelines (on- and offshore) and ships (including utilities) – and for each of these presents detailed cost elements and key cost drivers. These may be combined in a variety of ways – from a single source to a single sink, developing into qualified systems with several sources, networks and several storage sites over time.

Several likely transport networks of varying distances are therefore presented, including total annual costs and a cost per tonne of CO_2 transported. The cost models operate with three legs of transport: feeders, spines and distribution, each of which may comprise on- or offshore pipelines or ships. For some pipeline cases, CAPEX per tonne per km is also presented, providing a tool for comparison.

Table 1: Cost estimates (in €/t CO_2) for commercial natural gas-fired power plants with CCS or coal-based CCS demonstration projects with a transported volume of 2.5 Mtpa

Distance km	180	500	750	1500
Onshore pipeline	5.4	n. a.	n. a.	n. a.
Offshore pipeline	9.3	20.4	28.7	51.7
Ship	8.2	9.5	10.6	14.5
Liquefaction (for ship transport)	5.3	5.3	5.3	5.3

For commercial natural gas-fired power plants with CCS, or coal-based CCS demonstration projects, a typical capacity of 2.5 Mtpa and "point-to-point" connections are assumed. Table 1 shows the unit transportation cost (€/tonne) for such projects, depending on transport method and distance:

- Pipeline costs are roughly proportional to distance, while shipping costs are only marginally influenced by distance. Pipeline costs consist mainly (normally over 90%) of CAPEX, while for shipping, CAPEX is normally under 50% of total annual costs.
- If the technical and commercial risks are also considered, the construction of a "point-to-point" offshore pipeline for a single demonstration project is obviously less attractive than ship transportation for distances also below 500 km. (Pipeline costs here exclude any compression costs at the capture site, while the liquefaction cost required for ship transportation is specified.)

Table 2: Cost estimates for large-scale networks of 20 Mtpa (€/tonne CO_2). In addition to the spine distance, networks also include 10 km-long feeders (2*10 Mtpa) and distribution pipelines (2*10 Mtpa)

Spine Distance km	180	500	750	1500
Onshore pipeline	1.5	3.7	5.3	n. a.
Offshore pipeline	3.4	6.0	8.2	16.3
Ship (including liquefaction)	11.1	12.2	13.2	16.1

Once CCS is a commercially driven reality, it is assumed that typical volumes are in the range of 10 Mtpa serving one full-scale coal-fired power plant, or 20 Mtpa serving a cluster of CO_2 sources. The unit transportation cost for such a network with double feeders and double distribution pipelines is estimated in Table 2.

- Pipelines benefit significantly from scale when comparing costs with the 2.5 Mtpa point-to-point solutions in Table 1, whereas the scale effects on ship transport costs are less significant. (Shipping costs here include the costs for a stand-alone liquefaction unit, i.e. remote from the power plant.)

- Ship investments are further assumed to have a residual value for hydrocarbon transportation, as well as being able to serve other CO_2 projects, which will be considered in any evaluation of project risks. All cost estimates are based on custom design and new investment, i.e. no re-use of existing pipelines or existing semi-refrigerated LPG tonnage.

These figures assume full capacity utilisation from day one, which will probably be unrealistic for a cluster scenario. If, for example, volumes are assumed to be linearly ramped up over the first 10 years, this increases the unit cost of pipeline networks by 35-50% depending on maximum flows. For ships, ramp-up is achieved by adding ships and utilities when required, resulting in only marginal unit cost increases. To illustrate this, a calculation of the sensitivity of four key factors on pipeline transport was performed (Figure 18).

Figure 18: Sensitivity of four key factors on offshore pipeline costs, 10 Mtpa and 500 km when calculated as €/tonne CO_2 (see ZEP report on the Costs of CO_2 Transport)

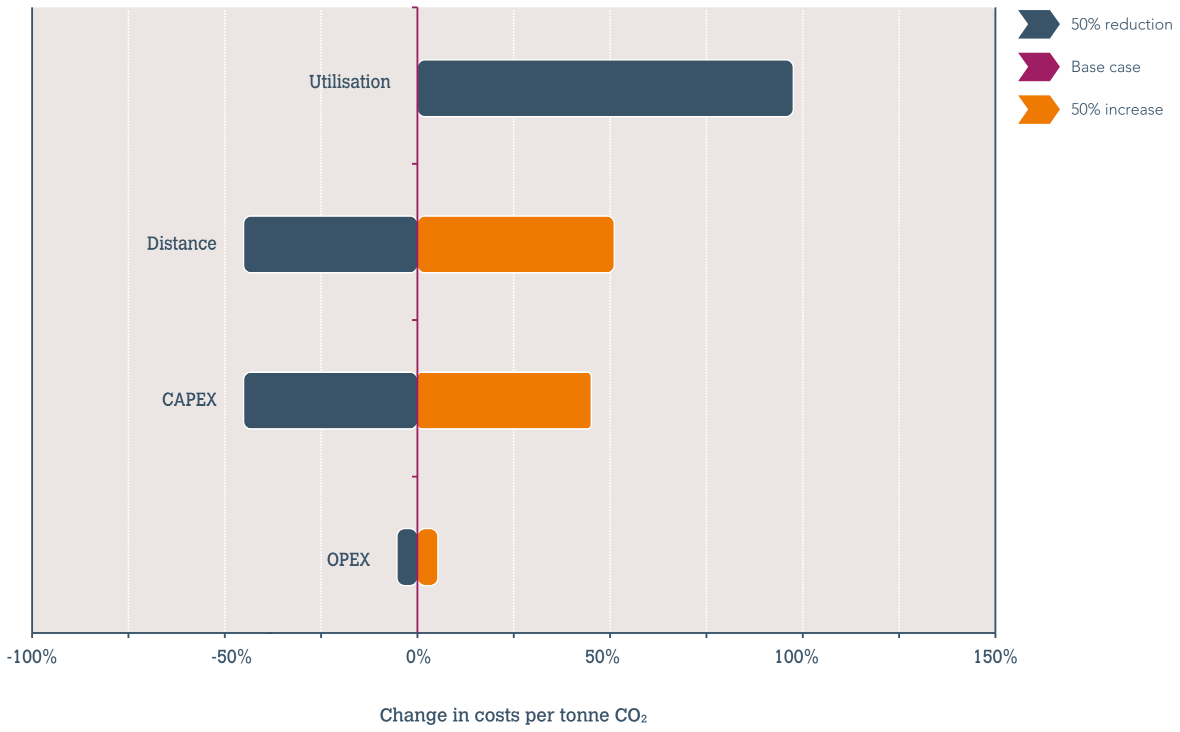


Figure 18 shows that utilisation, distance and CAPEX almost linearly influence the cost, since this is dominated by capital costs, which are almost linear to length of the pipe.

In conclusion, the main aim of this report is to provide cost estimates for large-scale CCS, rather than recommend generic modes of transport. However, assuming that high CAPEX and high risk are obstacles to rapid CCS deployment, combining ship and pipe transport in the development of clusters could provide cost-effective solutions – especially for volume ramp-up scenarios. For short to medium distances and large volumes, on the other hand, pipelines are by far the most cost-effective solution, but require strong central coordination.

For full details of underlying assumptions and cost calculations, see the individual report on CO_2 transport: www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html

CO_2 Storage

Publicly available data on CO_2 storage costs barely exists. As the development of a generic model was not possible from a time and resources perspective, the study utilised the technical and economical knowledge of ZEP members who have substantial research and experimental experience in the area of CO_2 storage and associated costs. As the IEA Greenhouse Gas R&D Programme[20] was also planning a similar project, the work was carried out as joint venture: a "bottom-up" approach was taken, based on potentially relevant cost components, and data consolidated into a robust and consistent model.

The availability and capacity of suitable storage sites developed into a key consideration. Data were made available from the EU GeoCapacity Project[21] database, comprising 991 potential storage sites in deep saline aquifers (SA) and 1,388 depleted oil and gas fields (DOGF) in Europe.

In terms of *numbers*, the majority are below an estimated capacity of 25-50 Mt, which corresponds to the need for more than five reservoirs to store the 5 Mtpa[22] reference single stream of CO_2 for 40 years and is assumed to be uneconomical. However, the majority of estimated capacity is found in very large DOGF and SA (>200 Mt capacity). In the commercial phase, exploration activities should therefore focus on large reservoirs which are capable of storing CO_2 from both single *and* multiple sources.

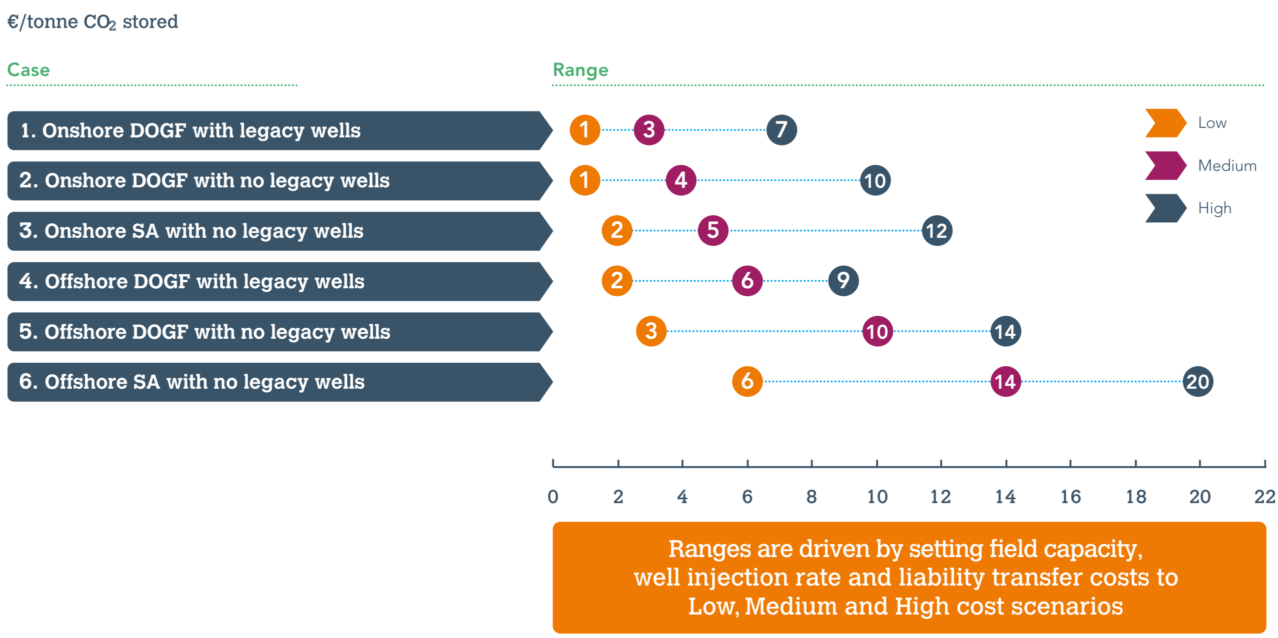
In order to cover the range of potential storage configurations and still provide reliable cost estimates, storage was divided in six main "typical" cases according to major differentiating elements:

- DOGF vs. SA; offshore vs. onshore.
- Whether there is the possibility of re-using existing ("legacy") wells.

For each of the six cases, three scenarios (Low, Medium and High) were defined to give a cost range estimate for each case (Figure 19).

N.B. The decision was made to restrict this costing exercise to reservoirs with a depth of 1,000 to 3,000 m.

Figure 19: Storage cost per case, with uncertainty ranges; purple dots correspond to base assumptions



[20] www.ieagreen.org.uk
[21] www.geology.cz/geocapacity
[22] In the commercial phase

Figure 19 shows that:

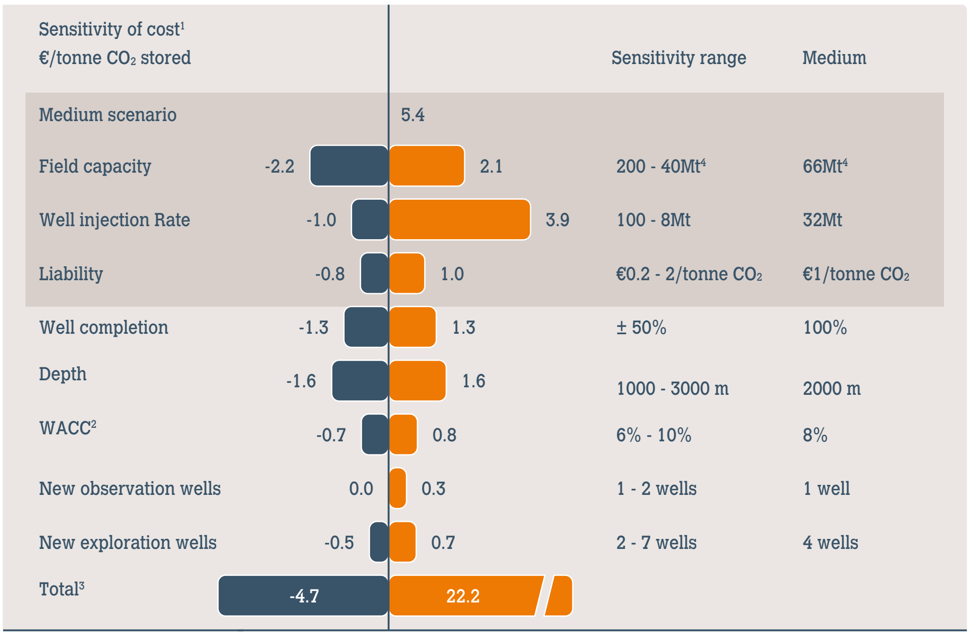
- There is a wide cost range within each case, the High cost scenario being up to 10 times more expensive than the Low cost scenario. This is mainly due to natural variability between storage reservoirs (i.e. field capacity and well injectivity) and only to a lesser degree to uncertainty in cost parameters. Despite this, the following trends stand out:
  – onshore is cheaper than offshore
  – DOGF are cheaper than SA (even more so if they have re-usable legacy wells)
  – the highest costs, as well as the widest cost range, occur for offshore SA.

- The capacity of storage reservoirs in Europe, according to current understanding, exhibits a mirror image of these cost trends: there is more storage capacity offshore than onshore (especially for DOGF) and more in SA than in DOGF. In short, the cheapest storage reservoirs also contribute the least to total available capacity.

Sensitivity analyses were also carried out to determine which of 26 considered cost elements carried the most weight in terms of the variability of the final cost. To allow a transparent comparison between cost figures for the various cases, a 1:3 source-to-sink ratio was assumed as the base setting in all cases. (This may represent a slightly conservative assumption for SA.)

This is quantified in the sensitivity analysis illustrated below for one of the cases, showing the effect of eight major cost drivers: field capacity, well capacity (injectivity times the lifetime of the well), cost of liability, well completion, depth, WACC, number of new observation wells and number of new exploration wells. (The impact of the remaining 18 cost elements was found not to be significant enough to be taken into account).

Figure 20: Illustration of sensitivities in the storage cost calculations for one storage case



[1] The sensitivity denotes the individual effect of ranging a parameter on the total cost in Medium scenario
[2] Weighted Average Cost of Capital
[3] Parts do not add to total. Combined effect of variables is larger due to independencies
[4] High scenario is 1 emitter to 1 field; Medium scenario is 1 emitter to 3 fields; Low scenario is 1 emitter to 5 fields

Figure 20 shows that:

- Field capacity has either the largest or second largest effect in all cases – the selection of storage reservoirs with respect to their capacity is therefore a key element in reducing the cost of CO_2 storage.

- Well capacity is also an important factor in cost variations. Storage reservoir selection and the design and placement of wells are therefore of key importance for onshore storage. For offshore cases, well completion cost is the second contributor to variations in cost, reflecting the specificities of that environment.

For full details of underlying assumptions and cost calculations, see the individual report on CO_2 storage: www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

Sensitivity analysis for the integrated CCS cases

In order to analyse the robustness of the cost calculations for the CCS integrated projects, the variation of the results for some ingoing factors has been examined for a supercritical OPTI hard coal-fired power plant, with post-combustion capture and storage in an onshore SA (Table 3 and Figure 21 below).

- As anticipated, the capital cost dominates, in the sense that reduced running hours result in much higher cost; CAPEX and WACC also give relatively large variations. It is noted that plant life has a low sensitivity, since the cost calculation is based on the net present value of the investment and that which happens far in the future has little influence on the present situation. Storage costs also make a small contribution to overall costs, as does the efficiency of the capture (absorption–desorption) process due to the relatively cheap fuel.

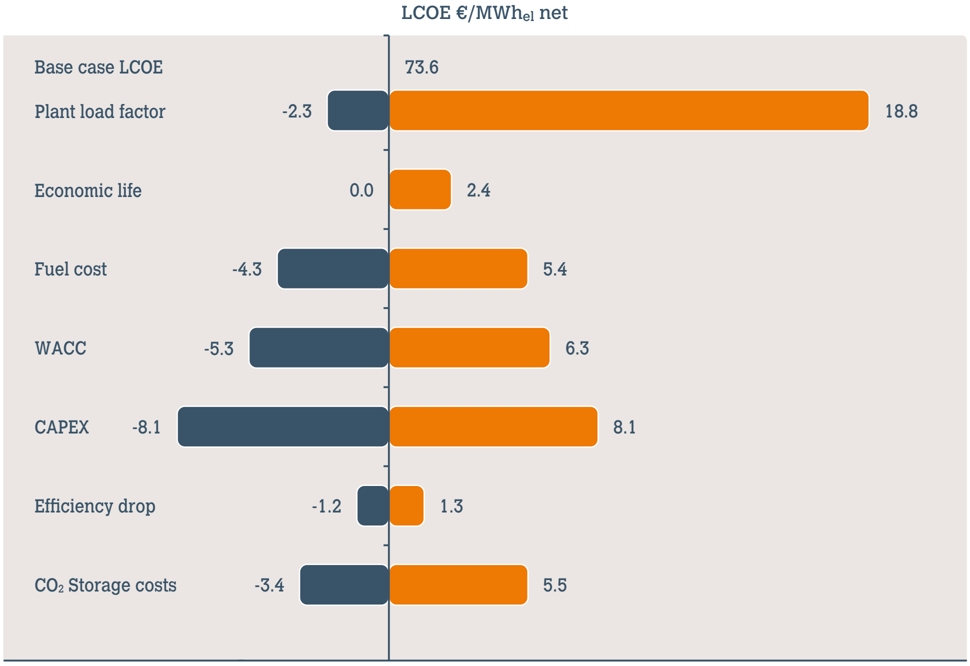
Table 3: Sensitivity parameters and ingoing factors for a supercritical OPTI hard coal-fired power plant, with post-combustion capture; short (180 km) point-to-point transport; and storage in an onshore SA

		Sensitivity parameters		
Ingoing factors		**Low LCOE**	**Medium LCOE***	**High LCOE**
Plant load factor	Hours/year	8,000	7,500	5,000
Economic life	Years	-	40	25
Fuel cost	€/GJ LHV	2	2.4	2.9
WACC	%	6%	8%	10%
CAPEX		–25%	-	25%
Reboiler duty; efficiency drop vs. Reference USC w/o capture	% points	5.5%	7.0%	8.5%

* Base case

CO_2 storage costs		**Low**	**Medium**	**High**
– CO_2 stored (capacity one field)	Mt	200	66	40
– CO_2 store rate (one field)	Mtpa	5.00	1.65	1.00
– CAPEX storage (one field)	M€	69.5	69.5	89.1
– CAPEX storage (one field)	M€ per (Mtpa)	13.9	42.1	89.1
– OPEX storage (one field)	M€ pa	2	3.1	4.2
– OPEX storage (one field)	€/tonne	0.40	1.88	4.20

Figure 21: Sensitivities of the calculated cost results for a hard coal-fired, supercritical OPTI power plant with post-combustion capture; short (180 km) point-to-point transport; and Medium storage costs for an onshore SA. The nominal cost for this case is €73.6/MWh



Glossary

CAPEX	Capital expenditure or investment
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CO_2	Carbon dioxide
DOGF	Depleted oil and gas fields
EU	European Union
EUA	Emission Unit Allowance
EUR	Euro
BASE	Base power plant with CO_2 capture
GJ	Gigajoule
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
Km	Kilometre
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
Leg	Re-usable Legacy Wells
LPG	Liquefied Petroleum Gas
M	Metre (metric)
M€	Millions of euros
Mt	Million tonnes
Mtpa	Million tonnes per annum
MWh	Megawatt hour
MW_{el}	Megawatt of electricity
OPTI	Optimised power plant with CO_2 capture
n.a.	Not applicable
NG	Natural gas
NPV	Net Present Value
NoLeg	Non Re-usable Legacy Wells
NGO	Non-governmental organisation
Offs	Offshore
Ons	Onshore
O&M	Operation and Maintenance
Pa	Per annum
PF	Pulverised Fuel
R&D	Research and Development
SA	Deep saline aquifer(s)
t	Tonne
TFT	ZEP Taskforce Technology
USC	Ultra supercritical
WACC	Weighted Average Cost of Capital
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants, known as the Zero Emissions Platform

Annexes

Annex 1: Basic data for integrated CCS projects

Table 4: Total LCOE for integrated CCS projects vs. reference plants without CCS (including various assumed costs for EUAs) using Low and High Fuel costs

	Single Plant - Single Sink Hard Coal				Single Plant - Single Sink Natural Gas		
	Ref	With CCS			Ref	With CCS	
Power Plant and CO_2 Capture							
• Power production (MWh_{el} net)	2 x 736	2 x 700			2 x 420	2 x 360	
• LCOE (€/MWh_{el} net) (Averages for OPTI plants) for Low - High fuel prices	43 - 51	65 - 75			46 - 90	64 - 115	
• LCOE Average All Plants (€/MWh_{el} net) for Low - High fuel prices	43 - 51	65 - 75			46 - 90	64 - 115	
CO_2 Transport							
• CO_2 volumes (Mtpa)	-	10			-	2.5	
• Distance (km)	-	180 + Feeder			-	180	
• LCOE (€/MWh_{el} net)	-	1.8			-	1.8	
CO_2 Storage							
• Type of storage		SAs Onshore				SAs Onshore	
• Cost scenario	-	Low	Mid	High	-	Mid	High
• CO_2 stored over 40 years (Number of reservoirs)x(Mt per reservoir)	-	2x200	6x66	10x40	-	1.5x66	2.5x40
• LCOE (€/MWh_{el} net)	-	1.7	4.6	9.9	-	1.8	3.9
TOTAL LCOE (€/MWh_{el} net) (Excluding Emission Unit Allowances) for Low - High fuel prices	43-51	69-79	72-82	77-87	46-90	68-119	70-121
Emission Unit Allowances within EU ETS Contribution to LCOE (€/MWh_{el} net)							
• For ETS 20 €/tonne CO_2	15	2			7	1	
• For ETS 40 €/tonne CO_2	30	4			13	2	
• For ETS 80 €/tonne CO_2	61	7			27	4	

Cluster			
Ref		With CCS	
Hard Coal	Nat Gas	Hard Coal	Nat Gas
3 x 736	2 x 420	3 x 700	2 x 360
43 - 51	46 - 90	65 - 75	64 - 115
	44 - 69		64 - 94
-		20	
-		500 + Feeders + Distribution Pipelines	
-		5.8	
		DOGFs Offshore	
-		Low / Mid / High	
-		4x200 / 12x66 / 20x40	
-		1.5 / 3.8 / 5.7	
	44-69	**71-101 / 74-104 / 75-105**	
11		2	
23		3	
45		6	

Cluster			
Ref		With CCS	
Hard Coal	Nat Gas	Hard Coal	Nat Gas
3 x 736	2 x 420	3 x 700	2 x 360
43 - 51	46 - 90	65 - 75	64 - 115
	44 - 69		64 - 94
-		20	
-		500 + Feeders + Distribution Pipelines	
-		5.8	
		SAs Offshore	
-		Low / Mid / High	
-		4x200 / 12x66 / 20x40	
-		3.5 / 8.7 / 12.4	
	44-69	**73-103 / 78-108 / 82-112**	
11		2	
23		3	
45		6	

Table 5: CAPEX for integrated CCS projects vs. reference plants without CCS

	Single Plant - Single Sink Hard Coal: Ref	Single Plant - Single Sink Hard Coal: With CCS			Single Plant - Single Sink Natural Gas: Ref	Single Plant - Single Sink Natural Gas: With CCS	
Power Plant and CO_2 Capture							
• Power production (MWh_{el} net)	2 x 736		2 x 700		2 x 420		2 x 360
• CAPEX (€/KW_{el} net) (Averages for OPTI plants)	1600		2660		786		1511
• CAPEX (M€)	2355		3916		660		1100
• CAPEX All Plants (M€)	2355		3916		660		1100
CO_2 Transport							
• CO_2 volumes (Mtpa)	-		10		-		2.5
• Distance (km)	-		180 + Feeder		-		180
• CAPEX (M€)	-		240		-		150
CO_2 Storage							
• Type of storage			SAs Onshore			SAs Onshore	
• Cost scenario	-	Low	Mid	High	-	Mid	High
• CO_2 stored over 40 years (Number of reservoirs)x(Mt per reservoir)	-	2x200	6x66	10x40	-	1.5x66	2.5x40
• CAPEX (M€ per reservoir)	-	69.5	69.5	89.1	-	69.5	89.1
• CAPEX (M€)	-	139	417	891	-	104	223
TOTAL CAPEX (M€)	**2355**	**4295**	**4573**	**5047**	**660**	**1354**	**1473**

- Table 5 shows that the capital intensity of fossil power plants will increase significantly with the addition of CCS. The overall CAPEX for gas power with CCS remains lower than for coal.

- As long as electricity market prices match the LCOEs (shown in Figure 5 for the Middle fuel costs), annual incomes will be sufficient to cover the annual costs for fuels, EUAs, O&M costs, as well as return the CAPEX (at the required interest rate) during the project lifetime. (For detailed data on annual costs for fuels, O&M and CAPEX, see the individual cost reports for CO_2 capture, transport and storage.)

Cluster			
Ref		With CCS	
Hard Coal	Nat Gas	Hard Coal	Nat Gas
3 x 736	2 x 420	3 x 700	2 x 360
1600	786	2660	1511
3533	660	5873	1100
	4193		6973

Ref	With CCS
-	20
-	500 + Feeders + Distribution Pipelines
-	1710

Ref	DOGFs Offshore		
-	Low	Mid	High
-	4x200	12x66	20x40
-	55.5	47.8	44.1
-	222	574	882
4193	**8905**	**9257**	**9565**

Cluster			
Ref		With CCS	
Hard Coal	Nat Gas	Hard Coal	Nat Gas
3 x 736	2 x 420	3 x 700	2 x 360
1600	786	2660	1511
3533	660	5873	1100
	4193		6973

Ref	With CCS
-	20
-	500 + Feeders + Distribution Pipelines
-	1710

Ref	SAs Offshore		
-	Low	Mid	High
-	4x200	12x66	20x40
-	237.6	198.6	169.3
-	950	2383	3386
4193	**9634**	**11066**	**12069**

The Costs of CO_2 Capture, Transport and Storage
The Costs of CO_2 Capture, Transport and Storage

Table 6: Overview of data for Integrated CCS cases – costs for power plants and CO_2 capture calculated for Middle fuel costs

Power Plants with Capture and CO_2 Compression/Conditioning

	Reference plant	Capacity	Additional	Captured CO_2			Avoided CO_2		Blocks
	Power Cost without Capture	One Block with Capture	Power Cost for Capture			Cost		Cost	
	(EUR/MWh$_{el}$ net)	(MWh$_{el}$ net)	(EUR/MWh$_{el}$)	(t/MWh$_{el}$)	(Mt CO_2 pa)	(EUR/t)	(t/MWh$_{el}$)	(EUR/t)	Nr of
Commercial hard coal									
Hard coal-fired plant	46	~ 700	23	0.85	~ 4.5	27	0.67	34	2
Commercial natural gas. In terms of CO_2 quantity, also demonstration hard coal/lignite with the same transport and storage costs per tonne CO_2.									
Natural gas combined cycle	69	~ 350	22	0.33	~ 1	67	0.28	79	~ 2
Natural gas combined cycle	69	~ 350	22	0.33	~ 1	67	0.28	79	~ 2
Natural gas combined cycle	69	~ 350	22	0.33	~ 1	67	0.28	79	~ 2
Hard coal-fired plant	46	~ 700	23	0.85	~ 4.5	27	0.67	34	2
Hard coal-fired plant	46	~ 700	23	0.85	~ 4.5	27	0.67	34	2*2
Weighted average:	**57**		**23**	**0.61**		**37**	**0.49**	**46**	

Similar costs for the capture technologies.
Average values for OPTI plants with capture according to ZEP CO_2 capture cost report.

1 gas turbine as in ZEP capture cost report. However, many other studies assume 2 gas turbines.
Post-combustion capture, OPTI, according to ZEP CO_2 capture cost report.

Transportation

	Network	Volume	Source/s/	Transport						Store/s/	Cost		Accumulated
				Feeder/s/		Spine		Distribution					Mt CO_2
		(Mtpa)	(#*Mtpa)	(km)	Type	(km)	Type	(km)	Type	(#)	(EUR/t)	EUR/MWh$_{el}$	(40 years)
Single Plant - Single Sink cases Demonstration and commercial CCS projects. Short transport distance onshore	1 a	10	1*10	10	Onshore	180	Onshore	0	–	1	2.1	1.8	400
Short transport distance onshore		2.5	1*2.5			180	Onshore			1	5.4	1.8	100
Clusters to benefit from large-scale infrastructure Could be developed if/when many commercial CCS projects are realised. Offshore	8 b	20	2.5	10	Onshore	500	Offshore	2*10	Offshore	2	9.5	5.8	800
			2.5	750	Ship								
			5	–	–								
			10	180	Offshore								

The Costs of CO_2 Capture, Transport and Storage
The Costs of CO_2 Capture, Transport and Storage

Table 6: Overview of data for Integrated CCS cases – costs for power plants and CO_2 capture calculated for Middle fuel costs

	Storage																INTEGRATED CCS CASE COSTS					
	Location	Type	Data quality	Legacy	Low Cost Scenario				Medium Cost Scenario				High Cost Scenario				Low Storage Cost Scenario		Medium Storage Cost Scenario		High Storage Cost Scenario	
					Field capacity	Fields	Cost		Field capacity	Fields	Cost		Field capacity	Fields	Cost			For CCS		For CCS		For CCS
				Wells	Mt CO_2	Nr of	€/t CO_2	€/MWh_{el}	Mt CO_2	Nr of	€/t CO_2	€/MWh_{el}	Mt CO_2	Nr of	€/t CO_2	€/MWh_{el}	€/t CO_2	€/MWh_{el}	€/t CO_2	€/MWh_{el}	€/t CO_2	€/MWh_{el}
Single Plant - Single Sink																						
Hard coal-fired plant	Onshore	Aquifer	Data-Poor	No	200	2.0	2.0	1.7	66	6.1	5.4	4.6	40	10	11.7	9.9	~ 31.2	~ 27	~ 34.6	~ 29	~ 40.9	~ 35
Natural gas combined cycle	Onshore	Aquifer	Data-Poor	No					66	1.5	5.4	1.8	40	2.5	11.7	3.9			~ 77	~ 26	~ 84	~ 28
Clusters																						
Natural gas combined cycle; Natural gas combined cycle; Hard coal-fired plant; Hard coal-fired plant	Offshore	DOGF	Data-Rich	Yes	200	4.0	2.4	1.5	66	12.1	6.2	3.8	40	20	9.4	5.7	~ 49	~ 30	~ 53	~ 32	~ 56	~ 34
	Offshore	Aquifer	Data-Rich	No	200	4.0	5.8	3.5	66	12.1	14.3	8.7	40	20	20.3	12.4	~ 52	~ 32	~ 61	~ 37	~ 67	~ 41
Weighted average:																						

Annex II: Participants in the ZEP CCS cost study

Surname	Name	Organisation	Remark
Antilla	Miko	Metso Power Oy	
Apeland	Sigve	Gassco	
Bassano	Claudia	ENEA	
Bauduin	Guy	GE Energy	
Berg Cortesi	Hanne	Bellona	
Bergmann	Heinz	RWE, ZEP Coordination Group Chair	
Buddenberg	Torsten	Hitachi Power Europe	
Buttinelli	Mauro	INGV	
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