Zero emissions platform

The Costs of CO_2 Capture

Post-demonstration CCS in the EU

European Technology Platform for Zero Emission Fossil Fuel Power Plants

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Executive Summary

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. Members of its Taskforce Technology have therefore now 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[2] and CO_2 storage[3] respectively. The resulting integrated CCS value chains, based on these three individual reports, are presented in a summary report.[4]

This report focuses on CO_2 capture.

- **Best estimates for new power plants with CO_2 capture in Europe, based on new, actualised data**

The cost calculations made in this study utilise new, actualised data provided by the industrial and utility members of ZEP and reviewed by the working group, based on their own extensive knowledge and experience. Indeed, many are already undertaking detailed engineering studies for EU CCS demonstration projects. This has enabled ZEP to estimate the Levelised Cost of Electricity (LCOE) and CO_2 avoidance costs for new-build commercial power plants with CO_2 capture that would enter into operation in the early 2020s, located at a generic greenfield site in Northern Europe. **N.B. Cost estimates do not include any additional site-specific investments.**

Costs for CO_2 capture include the capture process, plus the conditioning and compression/liquefaction of the captured CO_2 required for transport. The technologies studied are first-generation capture technologies: post-combustion CO_2 capture; IGCC with pre-combustion capture; and oxy-fuel for hard coal, lignite and natural gas, where applicable. (Costs for the transport and storage of CO_2 are not included.)

For each technology, a range of costs has been developed, with low-end costs based on more ambitious power plant designs that depend on a completely successful demonstration of the technology, the inclusion of technology improvements, refined solutions and improved integration. In this study, such plants have been termed "*OPTI*", which represents an optimised cost estimation.

The more conservative, high-cost plant designs are termed "*BASE*" for a plant representing today's technology choices, employing the most commercial designs while adopting a conservative approach to risk,

[1] International Energy Agency, World Energy Outlook, 2009
[2] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[3] www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html
[4] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

component redundancy and design performance margins. This case represents a highly conservative cost level. No development curve has been used to derive the OPTI power plant from a BASE power plant; and indeed if the demonstration phase is completely successful, it may be possible to skip the BASE and build an OPTI straight away. In addition, as CO_2 capture is an emerging technology, cost improvement through learning curves can be expected for both the BASE and OPTI designs.

All costs have been referenced to second quarter 2009 investment costs, with the LCOE and CO_2 avoidance costs of each plant concept calculated according to the boundary conditions and fuel costs established in the study. Importantly, the clear definition of the boundary conditions will enable future comparison with other studies. Whilst the costs obtained in this study are not definitive final costs, they represent the current best estimation of ZEP supported by their considerable experience. In short, they represent a "snapshot" based on current engineering knowledge and will be refined on an ongoing basis in line with technology developments and the progress of EU CCS demonstration projects.

- **The results**

For a hard coal-fired power plant (based on second quarter 2009, equipment cost levels and a fuel cost of €2.4/GJ), it has been calculated that the addition of CO_2 capture and the processing of the CO_2 for transport will increase the LCOE from ~€45/MWh to ~€70/MWh, depending on the capture technology for a new-build OPTI power plant design (Figure 1):

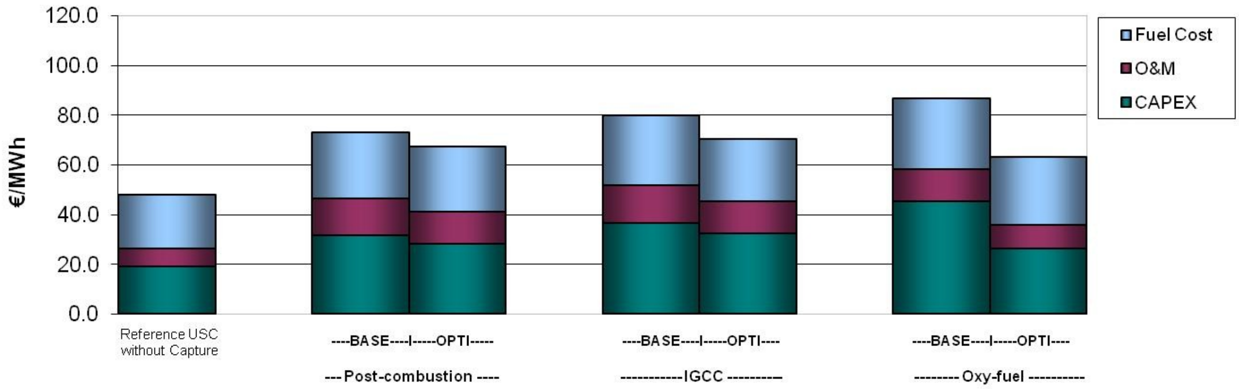


Figure 1: LCOE for hard coal-fired power plants with CO_2 capture

The CO_2 avoidance costs for capture are calculated to be in the range €30-40/tonne of CO_2 for an OPTI early commercial power plant design (Figure 2):

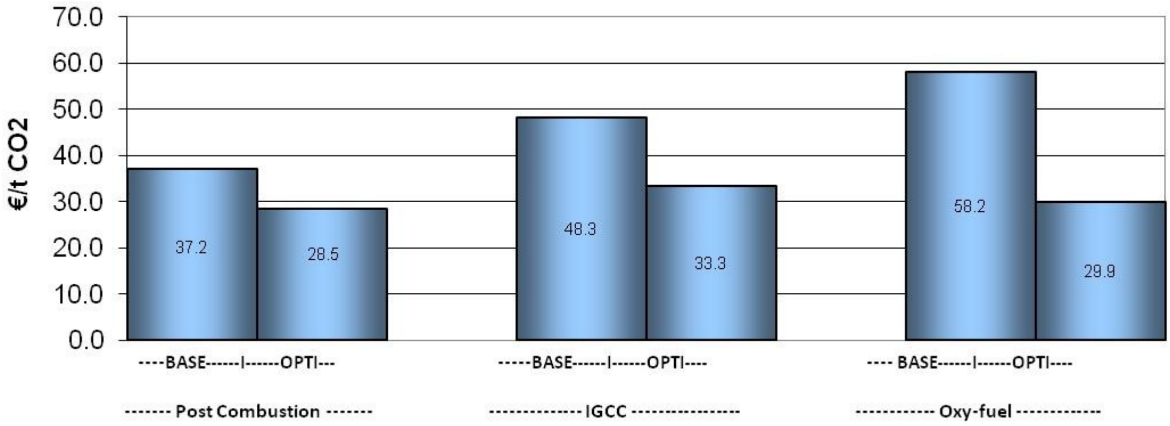


Figure 2: CO_2 avoidance costs for hard coal-fired power plants with CO_2 capture

Calculations undertaken for lignite-fired power plants with CO_2 capture also 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 (including pre-drying of the lignite), while results for an OPTI natural gas combined cycle power plant with post-combustion capture show the heavy dependence of fuel costs on the final result (Figure 3). Indeed, at the lower end of the cost range for natural gas, the LCOE is competitive with other fuel sources, being ~€65/MWh for a fuel price slightly under €5/GJ.

Although the results place the costs of IGCC with pre-combustion capture slightly higher than those of post-combustion capture, and oxy-fuel appears to have a larger range of values with some studies indicating that this technology has the lowest cost, there is no clear difference between any of the capture technologies and all three could be competitive in the future, if successfully demonstrated.

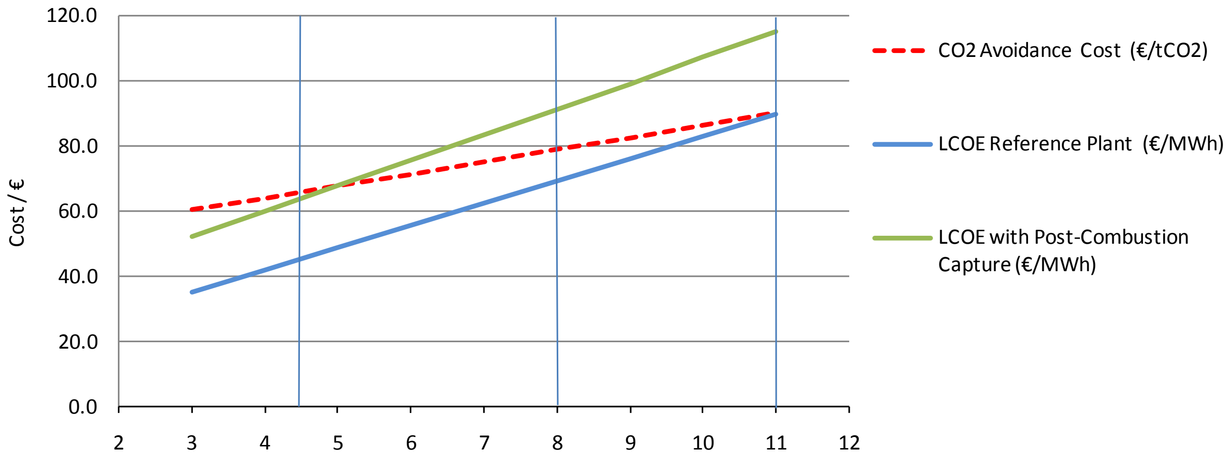


Figure 3: Dependence on the natural gas price for post-combustion capture

The EU CCS demonstration programme is therefore essential in order to:

- Validate each capture technology and power plant concept using different fuels;
- Confirm that capture technologies can achieve high plant availabilities so costs remain competitive; and, most importantly,
- Determine the real costs for each case.

There is also an urgent need to drive down the costs of CO_2 capture and compression through new, well-targeted R&D programmes, such as those defined in ZEP's 2010 report "Recommendations for research to support the deployment of CCS in Europe beyond 2020".[5] CO_2 capture is an emerging technology and historical experience with comparable processes suggests that significant improvements are achievable. The potential cost benefits of future promising capture technologies are therefore also briefly discussed.

The costs obtained in this study cannot be compared directly to other published studies, as the boundary conditions tend to be different, which impacts on the final result. However, a simplistic comparison has been made by extracting the technical and economic data, and recalculating the costs according to the boundary conditions for this study.

This shows that as CO_2 avoidance costs are higher for less efficient subcritical steam power plants, state-of-the-art ultra supercritical steam conditions need to be considered as standard for new-build European power plants. The LCOE and CO_2 avoidance costs calculated in this study are also higher than those of previous European cost studies, probably 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, although this simplistic analysis does not permit any further detailed comparison.[6]

In all cost studies, there are degrees of technical and economic uncertainty in the power plant concepts and no value can be considered to be a definitive cost. However, the conclusions of this study are based on new, actualised data and the extensive experience of key industry players, many of whom are now developing large-scale CCS projects.

In short, ZEP considers the costs determined in this study to represent the best current estimate for new-build commercial power plants with first-generation CO_2 capture technologies, entering into operation in Europe in the early 2020s.

[5] www.zeroemissionsplatform.eu/library/publication/95-zep-report-on-long-term-ccs-rad.html
[6] See Chapter 4, page 53

Key conclusions

CO_2 capture is an emerging technology and historical experience with comparable processes suggests that significant improvements are achievable. However, as it represents 80-90% of the costs of integrated CCS projects (~75% excluding the power plant), cost reduction must focus on capture – while keeping the costs of transport and storage low. The EU CCS demonstration programme is therefore essential in order to validate each capture technology and power plant concept using different fuels; confirm that capture technologies can achieve high plant availabilities so costs remain competitive; and most importantly, determine the real costs for each case.

- For hard coal-fired power plants based on second quarter 2009 equipment cost levels and a fuel cost of €2.4/GJ, the addition of CO_2 capture and the processing of CO_2 for transport increases the LCOE from ~€45/MWh to ~€70/MWh, depending on the capture technology for an optimised (OPTI) power plant design entering into operation in the early 2020s. This is equivalent to CO_2 avoidance costs of €30-40/t.
- Although the results position the costs of IGCC with pre-combustion capture slightly higher than those of post-combustion, and oxy-fuel appears to have a larger range of values (with some studies indicating it has the lowest cost), there is no clear difference between any of the capture technologies and all could be competitive in the future if successfully demonstrated.
- For natural gas CCGT power plants with post-combustion capture, the final result is heavily dependent on the fuel cost. Although CO_2 avoidance costs are more than double those of hard coal-fired power plants, due in part to the lower CO_2 production, when the natural gas fuel cost is lower than €5/GJ, the LCOE is competitive with that of hard coal-fired power plants.
- For lignite-fired power plants with CO_2 capture, CO_2 avoidance costs could be in the range of €30/t CO_2 for an OPTI power plant with pre-drying of the lignite.

1 Study on CO_2 Capture Costs

1.1 Background

In 2006, ZEP launched its first Strategic Deployment Document (SDD) and Strategic Research Agenda (SRA) for CO_2 Capture and Storage (CCS). The goal: to provide a clear strategy for accelerating its deployment as a critical technology for combating climate change. The conclusion: an integrated network of demonstration projects should be implemented urgently EU-wide in order to ensure CCS is commercially available by 2020.

In 2008, ZEP then carried out an in-depth study[7] into how such a demonstration programme could work in practice, from every perspective – technological, operational, geographical, political, economic and commercial. This approach was endorsed by both the European Commission and European Council; and by 2009, two key objectives had already 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.[8]

As importantly, ZEP has published its long-term R&D[9] plan for next-generation CCS technologies to ensure rapid deployment post-2020. Now, ZEP experts have identified the key cost elements and forecast the long-term cost of CO_2 capture – in the context of CO_2 transport and storage solutions – in order to provide the most complete and consistent analysis to date. Indeed, this has been undertaken in parallel with similar work on transport[10] and storage[11] costs, and should be assessed in conjunction with these results.

An analysis of integrated CCS value chains, based on the results of the three individual reports, are presented in a summary report.[12]

1.2 Use of new, actualised data

The technical and economical data used to calculate the cost estimates are *new actualised data,* provided and reviewed by members of ZEP's Taskforce Technology. Indeed, many are participating in EU CCS demonstration projects and are already undertaking detailed engineering and/or pre-FEED studies for new-build first-generation CO_2 capture power plants using different fuels. The technologies studied include post-combustion CO_2 capture, IGCC with pre-combustion capture and oxy-fuel for hard coal, lignite and natural gas, where applicable.

While not definitive, the results may therefore be considered a current snapshot of perceived 'real' costs for developing new-build commercial power plants with first-generation CO_2 capture technologies that would enter into operation in the early 2020s. The plants are assumed to be located at a generic location in Europe. **N.B. Cost estimates do not include any additional site-specific investments.**

1.3 Calculation of the Levelised Cost of Electricity and CO_2 avoidance costs

Investment, operation and maintenance cost data, combined with the design parameters and net plant efficiency, have then been used to calculate the Levelised Cost of Electricity (LCOE) of the different power plant concepts with *and* without capture, while the CO_2 avoidance cost has been determined by referencing the costs and emissions of power plants with capture to those of a state-of-the-art thermal power plant *without* CO_2 capture.

[7] www.zeroemissionsplatform.eu/library/publication/2-eu-demonstration-programme-co-2-capture-storage.html
[8] www.zeroemissionsplatform.eu/library/publication/125-sdd.html
[9] www.zeroemissionsplatform.eu/library/publication/95-zep-report-on-long-term-ccs-rad.html
[10] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[11] www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html
[12] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

The total investment cost for each concept includes the Engineering Procurement and Construction costs (EPC) of the power plant, as well as the Owner's Costs to develop the project. The Owner's Costs are those incurred during the planning, designing and commissioning phases of the power plant and include a contingency for any deviations. However, no site-specific costs have been included for grid connection etc.

Boundary conditions established for the study also, of course, have a significant impact on the final results and their transparent definition should enable future comparison with other studies (see pages 12-17). In this study, all investment costs are fixed to materials' costs for the second of quarter 2009. For plant and equipment costs based on other time periods, data have been adjusted to second quarter 2009 costs by applying the Cambridge Energy Research Associates (CERA) cost index curve (see page 14).

For each technology, a range of costs has been developed, with low-end costs based on more ambitious power plant designs that depend on a completely successful demonstration of the technology, the inclusion of technology improvements, refined solutions and improved integration. In this study, such plants have been termed "*OPTI*", which represents an optimised cost estimation.

The more conservative, high-cost plant designs are termed "*BASE*" for a plant representing today's technology choices, employing the most commercial designs while adopting a conservative approach to risk, component redundancy and design performance margins. This case represents a highly conservative cost level. No development curve has been used to derive the OPTI power plant from a BASE power plant; and indeed if the demonstration phase is completely successful, it may be possible to skip the BASE and build an OPTI straight away. In addition, as CO_2 capture is an emerging technology, cost improvement learning curve can be expected for both BASE and OPTI designs.

2 Boundary Conditions

This study has calculated the LCOE and CO_2 avoidance costs for various types of new-build commercial power plants with CO_2 capture that are expected to enter into operation in the early 2020s.

The LCOE takes into consideration plant capital costs, O&M costs, fuel costs, site location and financial assumptions over the lifetime of the power plant in order to calculate the electricity cost without profit. The CO_2 avoidance cost of a capture technology is determined by comparing the LCOE and CO_2 emissions of a power plant concept with CO_2 capture against a reference power plant without CO_2 capture.

Some of the data employed in these calculations is obviously specific to the capture technology option, whilst other data is common/reference data specific to this cost study and applied in all cases. As these boundary conditions have a significant effect on the final results, the values assumed in this study are shown below so that the results may be compared to those of other cost studies in a transparent manner.

2.1 Technical boundary conditions

2.1.1 Reference power plants without CO_2 capture

In order to calculate the CO_2 avoidance costs for the power plant concepts with capture, the following reference power plants without CO_2 capture have been used in this study:

- Natural gas-fired single-shaft F-class Combined Cycle Gas Turbine producing 420 MWe net at an efficiency of 58% (LHV for BASE) or 60% (LHV for OPTI).
- Hard coal 736 MWe net pulverised fuel (PF) ultra supercritical (280 bar 600/620ºC steam cycle) power plant
- Lignite-fired 989 MWe net PF ultra supercritical (280 bar 600/620ºC steam cycle) power plant and a lignite-fired 920MWe net PF ultra supercritical (280 bar 600/620ºC steam cycle) power plant with pre-drying of the lignite.

The generic technical parameters of each reference power plant case are shown in the following table:

Parameters		**PF Hard Coal**	**PF Lignite-Fired**		**CCGT (F-class)**
Net Electricity Output	MWe	736	989	920	420
HP Turbine Steam Inlet Pressure	Bara	280	280	280	113.8/27.7/3.99
HP Turbine Inlet Temperature	ºC	600	600	600	549
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620	620	549
Net Full Load Plant Efficiency	% LHV	46%	43%	48%	58% (BASE) 60% (OPTI)
Plant Load Factor	h/year	7,500	7,500		7,500
Plant Life	Year	40	40		25
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.759	0.930		0.347

N.B. An IGCC plant without CO_2 capture has not been selected as a reference power plant case because these types of plants have not been constructed in the last decade and the four existing IGCC power plants are best described as first-of-a-kind demonstration plants. As no reliable cost data therefore exists, it was therefore decided to reference the IGCC power plants with CO_2 capture against the pulverised coal power plants without CO_2 capture. The pulverised coal thermal power plant is the standard state-of-the-art model used today for coal-fired generation.

Both the reference power plants and those with capture analysed in this study are designed to comply with the future Industrial Emissions Directive (IED), which will supersede the Large Combustion Plant Directive (LCPD) in 2016. This directive limits the amount of NOx, SOx, CO and particulates that power plants may emit and thus determines the clean-up technologies that must be employed.

2.1.2 Ambient site conditions

As ambient conditions are site-specific, it was decided to use a fictional location that corresponds to ISO standard conditions for an inland construction site with natural draught cooling towers:

- Ambient temperature: 15°C
- Ambient relative moisture: 60%
- Ambient pressure (absolute) 1013 mbar
- Condensing pressure: 48 mbar
- Cooling water temperature 18.2°C

It was also assumed that the site would be a greenfield site in Northern Europe, with no specific site development costs or on-site utility system investments to connect the power plant to the grid.

2.1.3 Operating conditions

Due to the inherent higher investment costs of thermal power plants with CO_2 capture, it is assumed that the power plants would operate in base load, operating for 7,500 hours per year.

2.1.4 CO_2 quality and compression/processing

Including the compression/processing of the captured CO_2 (to meet the requirements of the transport process) in the design and cost of the power plant concept enables any benefits arising from the integration of streams between the compression/processing island, capture plant and the power plant to be taken into account, as well as those synergies arising from using common plant infrastructures and utilities. This methodology also ensures that all the internally consumed electricity required for the CO_2 compression and processing is part of the capture penalty.

Requirements for CO_2 quality are defined by those for CO_2 transport, storage, environmental regulations and overall cost. There are generally no strong technical barriers to providing high purity captured CO_2, but high purity requirements are likely to incur additional costs and energy requirements, resulting in a loss of power plant efficiency. Significant work is ongoing, both via various demonstration projects and R&D institutes to determine the limits for impurities in the CO_2 stream related to both transport options and storage.

For this study, the following criteria have been assumed as a basis for CO_2 compression pressure and quality requirements for pipeline transport conditions that should permit the use of cost-effective carbon steel materials in CO_2 pipelines:

- CO_2 delivery pressure 100-110 bar
- CO_2 delivery temperature max. 30°C
- CO_2 quality:
    - CO_2 concentration >95.5%
    - Water content sufficiently low to ensure that no free water can form in any mode of operation
    - Total content of all non-condensable gases < 4% volume
    - Due to health and safety limits that would be associated with short-term sudden leakages in case of a rupture, the following were also assumed:

- H_2S <200ppm
- CO <2000ppm
- SO_2 <100ppm
- NOx <100ppm

N.B. The above criteria are those employed for this cost study and in no way reflect a CO_2 specification for pipeline transport.

However, if the initial transport from the power plant is possible by ship and the CO_2 can be loaded directly into the boat, the CO_2 needs to be conditioned and liquefied to the following conditions:

- CO_2 delivery pressure: around 7 bar
- CO_2 delivery temperature: down to around –55ºC
- CO_2 quality: as above

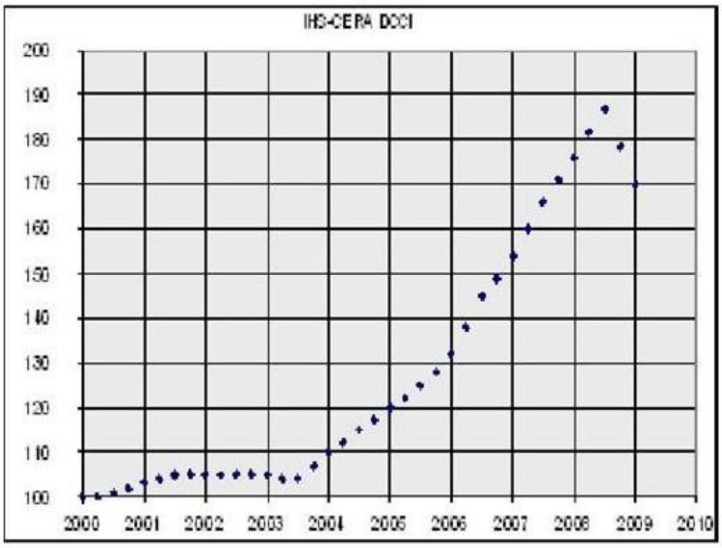
From the cost data supplied it is considered that both the investment and O&M costs, based on the same CO_2 capture and flow rate, are very similar for both options. The data also indicate that the processing of the captured CO_2 into conditions suitable for ship transport would require a slightly larger internal power penalty than that required for compression and processing for pipeline conditions. This larger internal power penalty results in a net final power plant efficiency of ~0.5% points lower. This difference is, however, well within the margin of variation for the estimations of such plants and the costs presented in this study can therefore be considered relevant for both transport options.

2.2 Financial boundary conditions: key assumptions

The following economic assumptions have been used in this study.

2.2.1 Investment costs

All the investment costs in this study are referenced to the second quarter of 2009 for materials costs. Cost data with plant and equipment costs referenced to a different time period have been adjusted to second quarter 2009 costs by applying the Cambridge Energy Research Associates (CERA) cost index curve below:



The total investment cost includes the Engineering Procurement and Construction (EPC) costs of the power plant, as well as the Owner's Costs to develop the project. The EPC costs include the complete power plant and a coal yard, where relevant, but exclude any harbour and mining facilities for fuel supply and transport. The Owner's Costs are those incurred during the planning, designing and commissioning phases of the power plant. They also include a contingency for any deviations. In this study, the Owner's Costs and contingency have been added as a percentage of the EPC costs as shown below:

- 10% for CCGT power plant
- 10% for hard coal PF power plants (15% for OPTI oxy-fuel power plant)
- 20% for the lignite power plant.

In Chapter 4 (see page 53) comparing the results obtained in this study with those of other previously published studies, the following currency exchange rates have been applied:

- Studies undertaken in 2005: €0.825 = $1
- Studies undertaken in 2006: €0.785 = $1
- Studies undertaken in 2007: €0.740 = $1
- Studies undertaken in 2008: €0.635 = $1
- Studies undertaken in 2009: €0.770 = $1 and £1.10

N.B. An exchange rate representative of the actual date of the original study has been applied.

2.2.2 Plant life

The operating life of all the new-build power plant concepts in this study, with and without capture, is considered to be:

- Natural gas-fired CCGT: 25 years
- Bituminous coal-fired power plants: 40 years
- Lignite-fired coal power plants: 40 years

2.2.3 Operation and maintenance costs

O&M costs are divided into fixed (€/year) and variable O&M costs (€/MWh). The fixed O&M costs include personnel and administration costs, spare parts and planned maintenance overhauls; variable O&M costs include the costs of consumables (water, limestone etc.) and disposal costs (ash, gypsum etc.).

The annual O&M cost escalation is assumed to be 2% in all cases.

2.2.4 Fuel costs

The selected fuel costs used in this study are ZEP's best estimations of a representative 2020 fuel cost. Due to the considerable uncertainty in predicting future fuel costs – especially in the case of natural gas, where there is a considerable difference of opinion on the future 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 selected are consistent with other detailed reviews, such as the EC Second Strategic Energy Review of November 2008 (for the year 2020), assuming the Base Case of Average Oil Scenarios and the current UK Electricity Generation Cost Update taken from the DECC website.

The following table identifies the fuel costs of the EC Second Strategic Energy review:

	Fuel cost in €/GJ					
	2010		2015		2020	
Oil price scenario	61$/bbl	100$/bbl	61$/bbl	100$/bbl	61$/bbl	100$/bbl
Oil	7.6	9.7	8.0	11.6	8.5	13.9
Gas	5.8	6.4	6.0	8.5	6.4	10.8
Coal	1.9	2.2	2.0	2.8	2.0	3.4

Inflation: 2%/year

EC Working Document "Europe's current and future energy position. Demand-resources-investments" for EU Second Strategic Energy Review, {COM(2008) 781 final}, Nov 2008

The table below identified the predicted fuel prices of the UK Electricity Generation Cost Update:

Average price 2015-2020 converted in €/GJ			
Scenario	Gas	Coal	Coal adv.
Low	4.29	1.53	2.75
Middle	8.11	2.35	5.75
High	11.23	2.90	8.33

Source: Mott MacDonald estimates based on DECC assumptions

The following fuel costs were selected for this study:

Fuel Costs	Low	Middle	High
Hard Coal – €/GJ	2.0	2.4	2.9
Lignite – €/GJ	1.39		
Natural Gas – €/GJ	4.5	8.0	11.0

A fuel escalation cost of 1.5% per annum is applied in the calculation.

2.2.5 Interest costs and other charges

In this study, the weighted average cost of capital (WACC) takes into account the equity rate, inflation and required rate of return on equity, i.e. it assumes that the inflation rate is equal for all costs and incomes during the project life. The WACC is assumed here to be 8.0%.

2.3 Summary of boundary conditions

The table below identifies the main assumptions and costs used in this study:

		Hard coal plant			Natural gas plant			Lignite plant
Reference year of study	year	Second quarter 2009						
Economic lifetime	years	40			25			40
Depreciation	years	40			25			40
Fuel price	EUR/GJ (LHV)	2	2.4	2.9	4.5	8	11	1.39
Fuel price escalation	% per year	1.5%			1.5%			1.5%
Operating hours per year	hours per year	7,500			7,500			7,500
Standard Emission factor	t/MWh_{th}	0.344			0.210			0.402
Common Inputs								
O&M cost escalation		2%						
Debt/Equity ratio	%	50%						
Loan interest rate	%	6%						
Interest during construction	%	6%						
Return on Equity	%	12%						
Start of debt service		Commercial operation						
Tax rate	%	35%						
WACC		8%						
Discount rate	%	9%						

Figure 4: Financial and other boundary conditions used in the study

3 CO_2 Capture Costs for First-Generation Technologies

In any calculations of this type, there will be degrees of technical and economic uncertainty in the power plant concepts. However, as the study shows no clear differences in the LCOE between any of the CO_2 capture technologies – post-combustion, pre-combustion and oxy-fuel – all three could be competitive in the future, if successfully demonstrated.

For example, the results suggest that the costs of the IGCC power plant with pre-combustion capture are slightly higher than those of the advance pulverised fuel (PF) power plant with post-combustion capture. However, there is more conservatism in the IGCC power plant design as it is not a common technology within the electrical sector and there are concerns regarding its ability to achieve high plant availabilities.

With respect to oxy-fuel capture, there is also a considerable spread in the cost results, with BASE plants with hard coal having the highest LCOE, but OPTI plants having the lowest. However, this reflects the fact that this technology is the least well-developed of the three options, causing greater uncertainty in the final power plant configuration.

The EU CCS demonstration programme is therefore essential as it will enable the validation of each power plant concept and determine the real costs of each technology. There is also an urgent need to drive down the costs of CO_2 capture and compression via new, well-targeted R&D programmes such as those defined in ZEP's 2010 report, "Recommendations for research to support the deployment of CCS in Europe beyond 2020".[13]

CO_2 capture is an emerging technology and historical experience with comparable processes suggests that significant improvements are achievable.

3.1 Hard coal

For hard coal, the following power plant concepts have been considered:

- Hard coal PF ultra supercritical (280 bar 600/620ºC steam cycle) power plant with post-combustion capture based on advanced amines
- Hard coal-fired 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)
- Hard coal oxy-fired PF power plant with ultra supercritical steam conditions (280 bar 600/620ºC steam cycle).

As previously stated, power plant costs are referenced to the second quarter of 2009 and three fuel prices assumed:

Fuel Costs	**Low**	**Middle**	**High**
Hard Coal – €/GJ	2.0	2.4	2.9

The following costs have been determined for each of the concepts studied. N.B. These costs are for CO_2 capture only and exclude costs for CO_2 transport and storage.

[13] www.zeroemissionsplatform.eu/library/publication/95-zep-report-on-long-term-ccs-rad.html

		Levelised Electricity Costs (LCOE) €/MWh	CO_2 Avoidance Cost €/t CO_2
Low Fuel Cost €2.0/GJ			
Reference Case – No Capture	State-of-the-Art	**44.4-44.6**	–
Hard Coal PF Post-Combustion Capture	BASE Early Commercial	68.5	36.0
	AVERAGE	65.9	32.1
	OPTI Early Commercial	62.9	27.5
Hard Coal IGCC with Pre-Combustion Capture	BASE Early Commercial	75.3	46.7
	AVERAGE	70.2	38.6
	OPTI Early Commercial	66.3	32.5
Hard Coal PF Oxy-Fuel	BASE Early Commercial	71.3-**81.9**	40.5-**56.6**
	(Ref Plant) OPTI Early Commercial	(39.1) **58.5**-64.3	**28.5**-37.6
Middle Fuel Cost €2.4/GJ			
Reference Case – No Capture	State-of-the-Art	**48.1-48.3**	–
Hard Coal PF Post-Combustion Capture	BASE Early Commercial	72.9	37.2
	AVERAGE	70.3	33.3
	OPTI Early Commercial	67.2	28.5
Hard Coal IGCC with Pre-Combustion Capture	BASE Early Commercial	80.0	48.3
	AVERAGE	74.7	39.8
	OPTI Early Commercial	70.5	33.3
Hard Coal PF Oxy-fuel	BASE Early Commercial	76.0-**86.7**	42.1-**58.2**
	(Ref Plant) OPTI Early Commercial	(42.8) **63.0**-69.1	**29.9**-39.3
High Fuel Cost €2.9/GJ			
Reference Case – No Capture	State-of-the-Art	**52.7-52.8**	–
Hard Coal PF Post-Combustion Capture	BASE Early Commercial	78.5	38.8
	AVERAGE	75.9	34.7
	OPTI Early Commercial	72.6	29.7
Hard Coal IGCC with Pre-Combustion Capture	BASE Early Commercial	85.9	50.3
	AVERAGE	80.2	41.2
	OPTI Early Commercial	75.8	34.4
Hard Coal PF Oxy-fuel	BASE Early Commercial	82.0-**92.6**	44.2-**60.2**
	(Ref Plant) OPTI Early Commercial	(47.4) **68.7**-75.1	**31.6**-41.4

N.B. In the case of oxy-fuel, where there exists a range of values for both the BASE and OPTI cases, the values identified in ***bold text*** *are those that have been used in the figures.*

Figures 5 and 6 show the data from the above table for the middle fuel cost of €2.4/GJ:

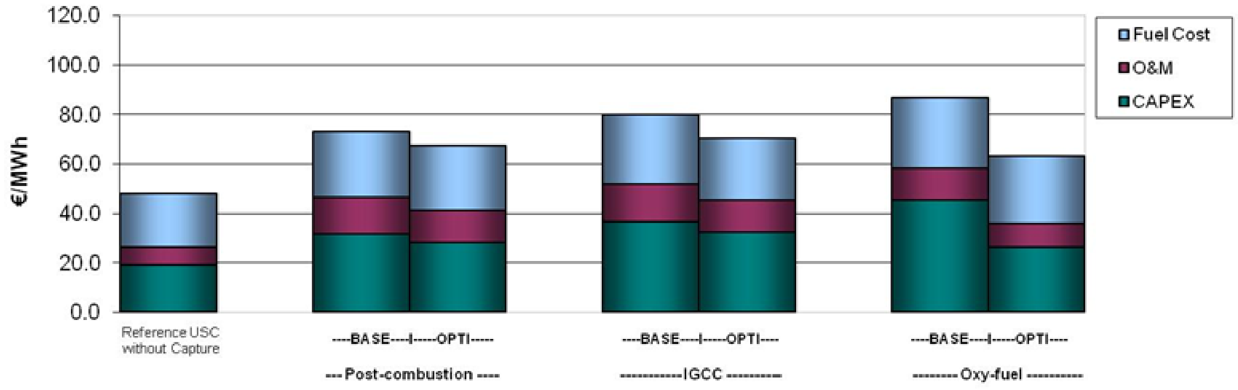


Figure 5: LCOE for hard coal-fired power plants with CO_2 capture

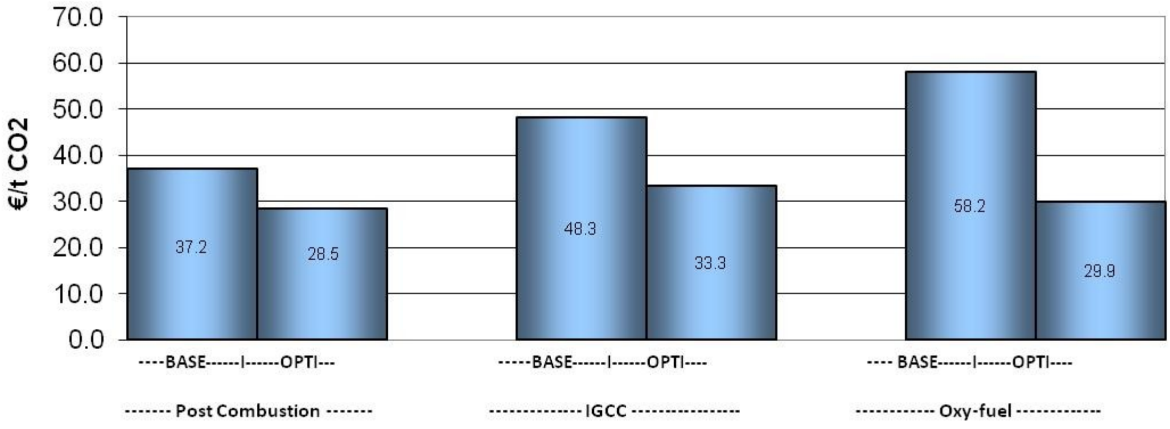


Figure 6: CO_2 avoidance costs for hard coal-fired power plants with CO_2 capture

Changing the fuel costs simply displaces the values, in a fairly consistent manner, as the plant efficiencies for each case are similar.

While it is difficult to draw concrete conclusions as the values represent a “snapshot” of the perceived real costs, the following observations can be made:

- As there is currently uncertainty as to the values of all three technologies, there is a clear need to demonstrate all options.
- The difference between the values of each technology is not sufficient to discard any of them and all three could be competitive.
- Costs for hard coal IGCC pre-combustion capture appear to be higher than those for post-combustion capture, but as electricity utilities are less familiar with pre-combustion, the cost figures

may simply be more conservative. Nevertheless, there is a clear need to target efforts at reducing the costs of the IGCC power plant and, in particular, the air separation process.

- The lower end of the LCOE for an OPTI plant with hard coal oxy-fuel is the lowest of the three first-generation capture technologies and potentially represents the cheapest option. However, there is a much larger spread of costs for oxy-fuel technology, as it is the newest technology.

In the following sub-sections, details are given for each hard coal power plant concept studied.

3.1.1 Hard coal PF coal-fired power plant with post-combustion capture

A post-combustion capture plant employing advanced amines with CO_2 compression was integrated into the reference hard coal PF ultra supercritical thermal power plant. The addition of the capture plant and compression island caused the net efficiency and power output of the reference power plant to decrease due to the energy demands of these processes. The parameters of the reference and power plant with capture are shown in the following table:

Parameters		Reference PF Hard Coal without Capture	PF Hard Coal with Post-Combustion Capture
Net Electricity Output	MWe	736	616
HP Turbine Steam Inlet Pressure	Bara	280	280
HP Turbine Inlet Temperature	ºC	600	600
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620
Net Full Load Plant Efficiency	% LHV	46%	38%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.759	0.918
CO_2 Capture Rate	%	–	90
CO_2 Captured	t/MWh	–	0.827

The following considerations can be made concerning the hard coal PF power plant with post-combustion capture:

- Its design is representative of one of the early commercial power plants – the higher cost range being indicative of a BASE power plant employing today's technologies and lower cost range of an OPTI commercial power plant, assuming foreseen improvements and improved integration.
- The capture power plant consists of two parallel capture trains based on a commercially available advanced amine for the most optimistic design (OPTI) and a three parallel capture trains system for the more conservative design (BASE).
- The steam turbine design has not been modified to reflect large steam extraction required for the CO_2 capture plant. Steam extraction is assumed to be taken from an overflow line and a valve is employed to hold pressure during part load operation.
- The main additional energy requirements leading to a 7%-9% real drop in power plant efficiency when compared to the reference power plant without capture are attributable to:
  - Steam extraction taken from between the intermediate pressure (IP) and low pressure (LP) turbine for the reboiler of the capture power plant
  - CO_2 compressor electrical drive
  - Additional ID fan.

The capture power plant design is essentially fairly conservative, as no improvements to the steam turbine are considered. There exists the possibility in the future of modifying the steam turbine, e.g. the LP turbine could be reduced in capacity, resulting in possible future cost savings. Improvements in amine sorbent performance and standardisation of the capture plant will also lead to future cost savings and efficiency improvements.

The economics of the power plants are shown in the following table:

Economics		**Reference PF Hard Coal without Capture**			**PF Hard Coal with Post-Combustion Capture**		
Performance Data							
Power plant capacity	MWe	736			616		
Investment Cost							
EPC cost	mill €	1,144 1,141-1,152			1,509 1,416-1,601		
EPC cost, net	€/kW	1,555 1,550-1,565			2,450 2,300-2,600		
Owner's Cost (including contingencies)	% EPC	10			10		
Total investment cost	mill €	1,259 1,255-1,267			1,660 1,558-1,762		
Fuel costs	€/GJ (LHV)	Low 2.0	Mid 2.4	High 2.9	Low 2.0	Mid 2.4	High 2.9
Operating Cost							
Fixed O&M	mill €/year	26.2			36.0 35.0-37.0		
Variable O&M	€/MWh	1			3,3 3.0-3.7		
Low Fuel Cost (€2/GJ)							
Levelised CAPEX	€/MWh	19 19.0-19.1			30 28.1-31.8		
Levelised O&M	€/MWh	7.1			13.7 13.1-14.5		
Levelised Fuel Cost	€/MWh	18.3			22.2 21.6-22.2		
Levelised Electricity Cost (LCOE)	€/MWh	**44.5 44.4-44.6**			**65.9 62.9-68.5**		
CO_2 Avoidance Cost	€/t CO_2	–			**32.1 27.5-36.0**		
Middle Fuel Cost (€2.4/GJ)							
Levelised CAPEX	€/MWh	19 19.0-19.1			30 28.1-31.8		
Levelised O&M	€/MWh	7.1			13.7 13.1-14.5		

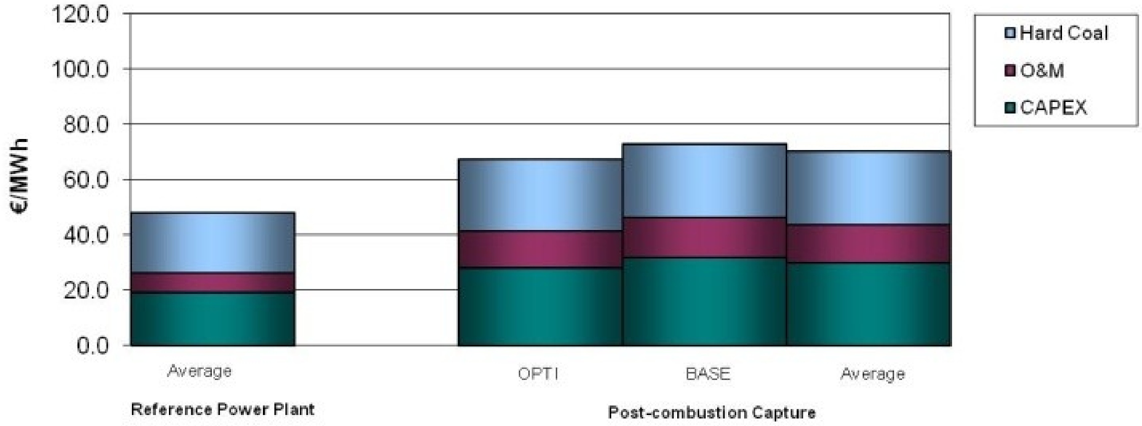
Levelised Fuel Cost	€/MWh	22.0	26.6 25.9-26.6
Levelised Electricity Cost (LCOE)	€/MWh	**48.1** **48.1-48.3**	**70.3** **67.2-72.9**
CO_2 Avoidance Cost	€/t CO_2	–	**33.3** **28.5-37.2**
High Fuel Cost (€2.9/GJ)			
Levelised CAPEX	€/MWh	19 19.0-19.1	30 28.1-31.8
Levelised O&M	€/MWh	7.1	13.7 13.1-14.5
Levelised Fuel Cost	€/MWh	26.6	32.2 31.3-32.2
Levelised Electricity Cost (LCOE)	€/MWh	**52.7** **52.7-52.8**	**75.9** **72.6-78.5**
CO_2 Avoidance Cost	€/t CO_2	–	**34.7** **29.7-38.6**

CO_2 avoidance costs are calculated to be in the range of €28.5 to €37.2/t CO_2 for the middle fuel cost of €2.4/GJ. The high end of the cost figure is considered to be more representative of a BASE early commercial power plant with three parallel capture trains, whilst the low end of the costs are deemed to be more representative of an OPTI early commercial power plant based on two parallel capture trains.

The fixed O&M costs for a power plant with capture are more than 35% higher than those for the reference power plant without capture. This increase takes into consideration both the maintenance of the capture plant as well as the additional labour required. This cost is considered to be on the high side, as it includes a conservative factor for the novel technological aspect of the capture plant. As the capture plants become standard and plant personnel become familiar with them, fixed O&M costs, in particular personnel costs, should reduce.

Variable O&M costs are expected to triple with respect to the reference plant without capture due to the additional chemical costs, cooling water charges and waste disposal costs. Indeed, future solvent costs and the quality of waste materials are two current "big unknowns" for this technology, with considerable uncertainty regarding these values.

In summary, Figure 7 (below) identifies the LCOE and CO_2 avoidance costs calculated for the hard coal PF power plant with post-combustion capture, based on the middle fuel cost of €2.4/GJ:



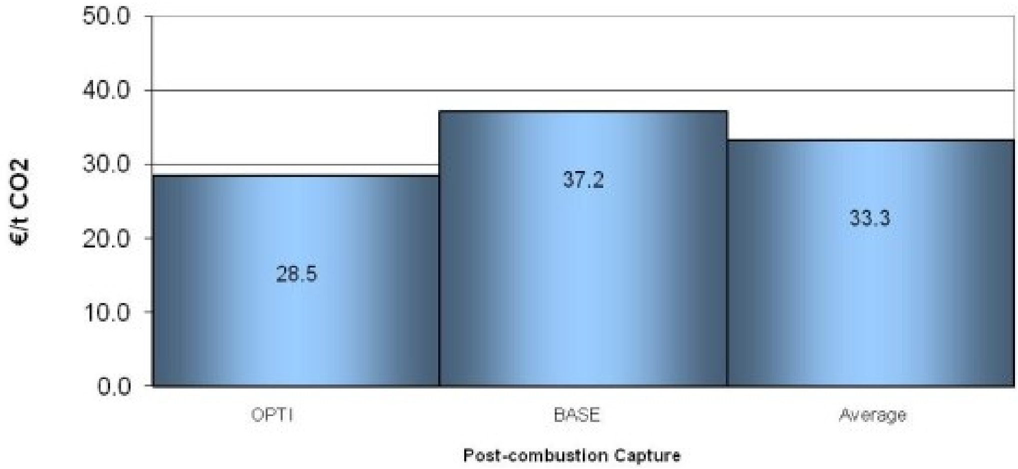


Figure 7: LCOE and CO_2 avoidance costs for hard coal-fired power plants with post-combustion capture

Figure 8 shows the impact on the LCOE and CO_2 avoidance costs for the OPTI post-combustion capture case varying the fuel costs:

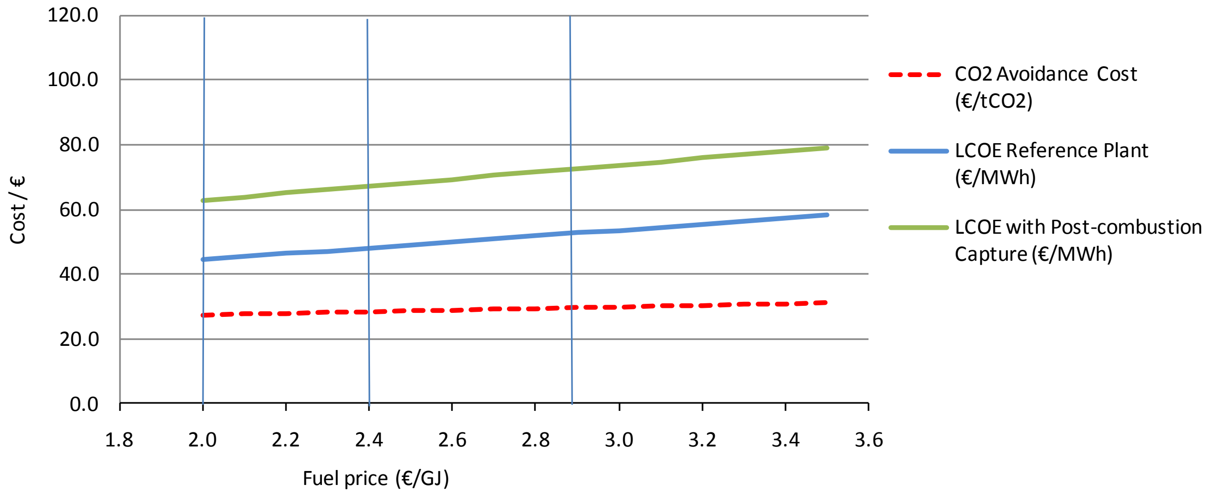


Figure 8: Dependence on the coal price for post-combustion capture (OPTI power plant)

3.1.2 Hard coal IGCC with pre-combustion capture

For this study, it was decided that it would be more representative to reference the IGCC power plant with CO_2 capture against the PF reference coal-fired power plant. Their design parameters are shown in the following table:

Parameters		Reference PF Hard Coal without Capture	IGCC – Full Water Quench design; Sour CO-Shift, H2Syngas Saturation and Dilution
Net Electricity Output	MWe	736	900
Net Full Load Plant Efficiency	% LHV	46%	38% 35.7%-40%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.759	0.918 0.873-0.978
CO_2 Capture Rate	%	-	90
CO_2 Captured	t/MWh	-	0.827 0.785-0.880

With respect to the IGCC power plant with pre-combustion CO_2 capture, the following can be assumed:

- A design representative of an OPTI early commercial power plant entering service into operation in 2020
- The use of a conventional cryogenic air separation plant
- An entrained pressurised gasifier with full water quench of 1,000 MWt
- No Air Side Integration
- Two-stage sour CO-Shift
- CO_2 separation with a physical solvent such as Rectisol or Selexol
- The design includes Claus tail gas treatment
- Resulting H_2 rich syngas is saturated and diluted before combustion
- Electrical drive CO_2 compressor.

The economics of such a power plant are shown in the following table:

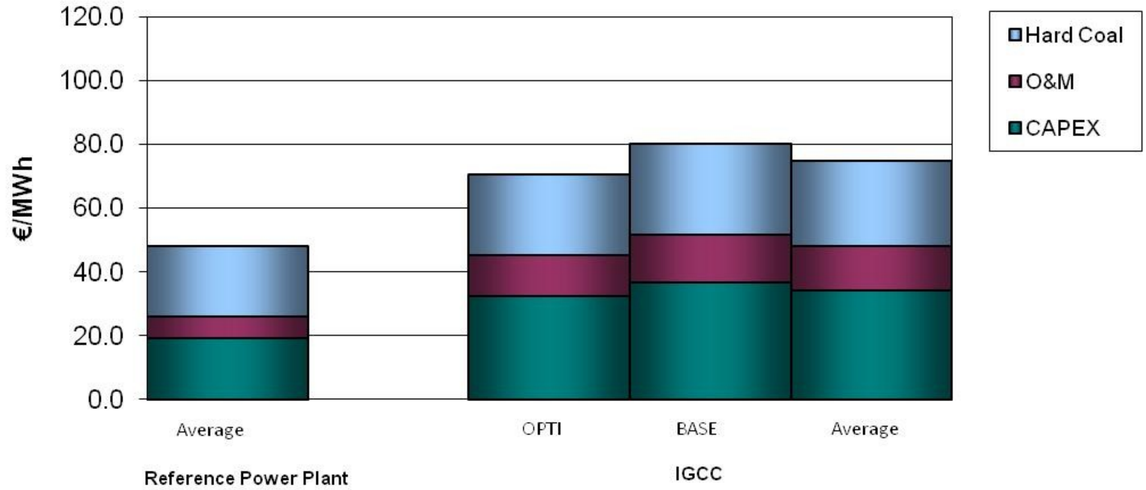
Economics			Reference PF Hard Coal without Capture			IGCC – Full Water Quench Design; Sour CO-Shift, H2Syngas Saturation and Dilution	
Performance Data							
Power plant capacity	MWe	736			900		
Investment Cost							
EPC cost	mill €	1,144 1,141-1,152			2,520 2,385-2,700		
EPC cost, net	€/kW	1,555 1,550-1,565			2,800 2,650-3,000		
Owner's Cost (including contingencies)	% EPC	10			10		
Total investment cost	mill €	1,259 1,255-1,267			2,772 2,624-2,970		
Fuel cost	€/GJ (LHV)	Low	Mid	High	Low	Mid	High
		2.0	2.4	2.9	2.0	2.4	2.9
Operating Cost							
Fixed O&M	mill €/year	26.2			63 60-68		
Variable O&M	€/MWh	1			1.8 1.5-2.1		
Low Fuel Cost (€2.0/GJ)							
Levelised CAPEX	€/MWh	19 19.0-19.1			34.3 32.4-36.7		
Levelised O&M	€/MWh	7.1			13.8 12.8-15.0		
Levelised Fuel Cost	€/MWh	18.3			22.2 21.1-23.6		
Levelised Electricity Cost (LCOE)	€/MWh	**44.5** **44.4-44.6**			**70.2** **66.3-75.3**		
CO_2 Avoidance Cost	€/t CO_2	–			**38.6** **32.5-46.7**		
Middle Fuel Cost (€2.4/GJ)							
Levelised CAPEX	€/MWh	19 19.0-19.1			34.3 32.4-36.7		
Levelised O&M	€/MWh	7.1			13.8 12.8-15.0		
Levelised Fuel Cost	€/MWh	22.0			26.6 25.3-28.3		
Levelised Electricity Cost (LCOE)	€/MWh	**48.1** **48.1-48.3**			**74.7** **70.5-80.0**		

CO_2 Avoidance Cost	€/t CO_2	–	**39.8** **33.3-48.3**
High Fuel Cost (€2.9/GJ)			
Levelised CAPEX	€/MWh	19 19.0-19.1	34.3 32.4-36.7
Levelised O&M	€/MWh	7.1	13.8 12.8-15.0
Levelised Fuel Cost	€/MWh	26.6	32.2 30.6-34.2
Levelised Electricity Cost (LCOE)	€/MWh	**52.7** **52.7-52.8**	**80.2** **75.8-85.9**
CO_2 Avoidance Cost	€/t CO_2	–	**41.2** **34.4-50.3**

The calculated CO_2 avoidance costs appear much higher than those published in other studies as the reference power plant in this case is a lower cost PF coal-fired power plant without capture.

There is a considerable spread for the costs between the BASE and OPTI cases, which is a reflection of the fact that the IGCC is not a common technology in the electricity sector and power companies are less familiar with these power plants. Compared to the reference PF power plant, the LCOE of an IGCC with CO_2 capture is predicted to be 46%-66% more expensive for the middle fuel price. The lower end of the CO_2 avoidance cost is similar to that of the PF power plant with post-combustion capture, but the top end is significantly higher. The increase in the fixed and variable O&M costs does take into account both the additional plant and extra chemical and catalyst costs.

In summary, Figure 9 identifies the LCOE and CO_2 avoidance costs calculated for a hard coal IGCC with pre-combustion capture based on a middle fuel cost of €2.4/GJ:



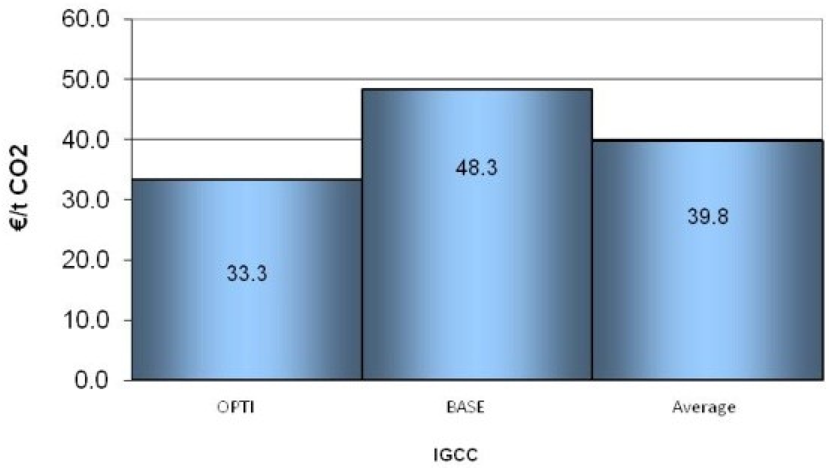
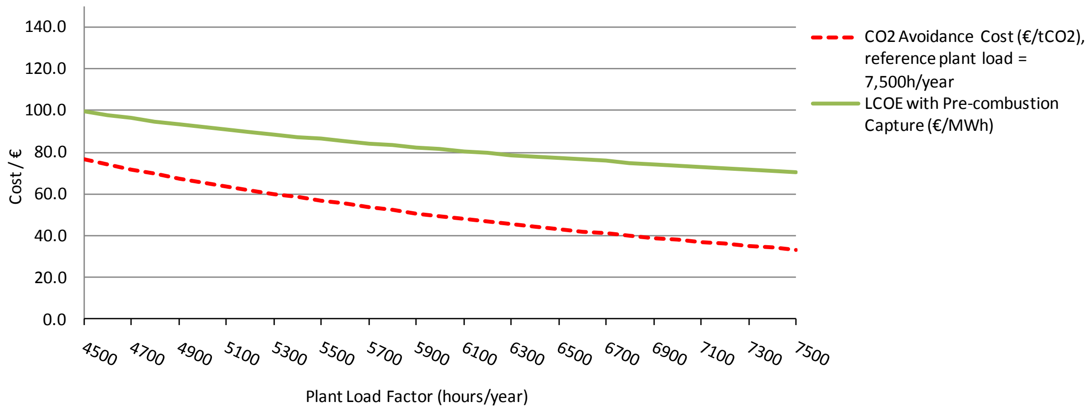


Figure 9: LCOE and CO_2 avoidance costs for hard coal-fired IGCC power plants

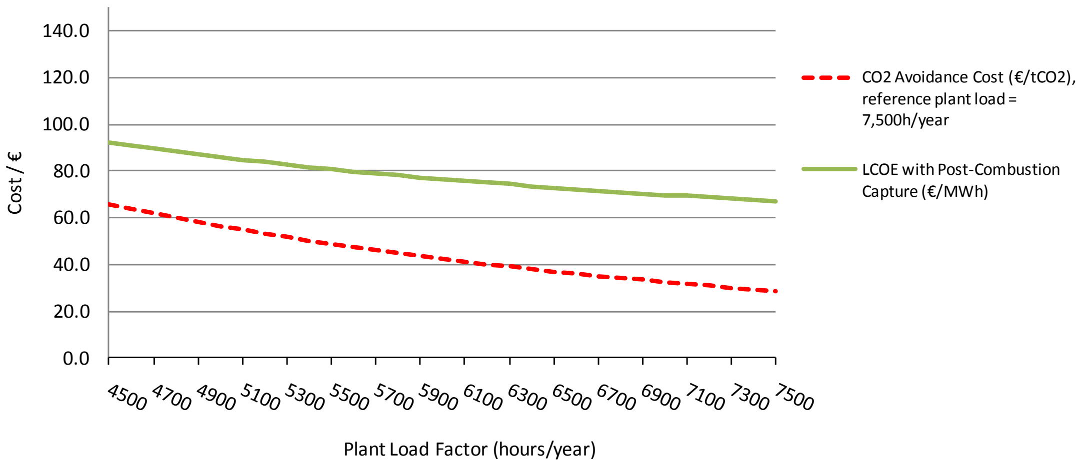
A key aspect for the demonstration of the next-generation of IGCC power plants with CO_2 capture is that these plants achieve high levels of plant availability and operate in base load, operating for 7,500 hours per year, so that costs can remain competitive (Figure 10).

This is particularly important for the pre-combustion case, as the IGCC power plant design is not a common technology within the electrical sector and there are some concerns as to whether these plants can achieve the high plant availability required.

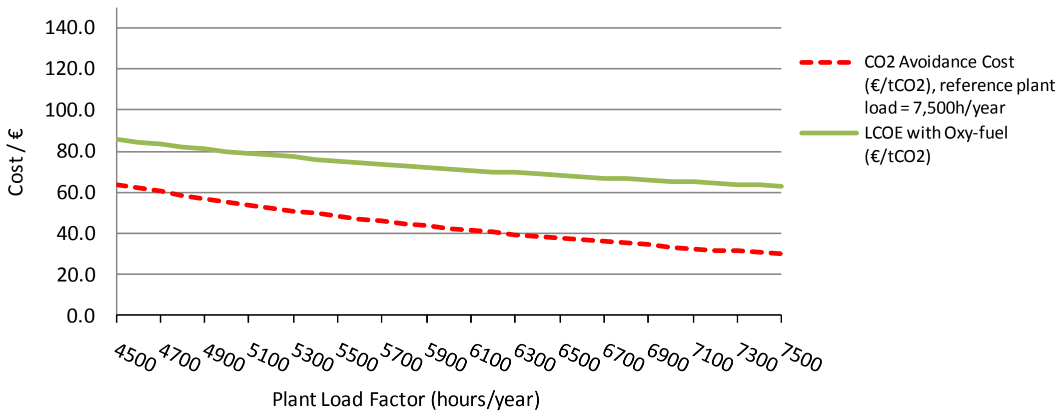
The possible impact of a reduction in operating hours on the LCOE and CO_2 avoidance costs is shown in the following graph (based on OPTI plant costs).



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 capture

Figure 10: Dependence on Plant Load Factor for all three coal technologies

A reduction from 7,500 hours of operation each year to 6,500 hours results in an increase in the LCOE from €74.7/MWh to €81.7/MWh, equivalent to an increase in the CO_2 avoidance cost of €5/tonne.

3.1.3 Hard coal oxy-fuel PF power plant

The studies concerning the hard coal PF oxy-fuel power plant are based around a state-of-the-art ultra supercritical steam cycle of 600/620ºC, 280 bar. Oxy-fuel is considered to be the least well-developed of the first-generation capture technologies and for this reason there is considerable variability in the cost estimations. This is due to differing assumptions in the final design configurations, the amount of contingencies considered for the less defined areas and future O&M costs.

For this reason, two separate cost studies have been developed:

- A conservative approach, which represents a BASE commercial power plant.
- An expected OPTI early commercial power plant design that represents a more ambitious design. Due to the more ambitious design of this power plant, the Owner's Costs were subsequently increased to 15% to allow for more contingency. It must also be noted that, in this study, this power plant was developed starting from a slightly different reference plant than for the conservative power plant design, hence the CO_2 avoidance cost is calculated against this reference power plant.

Consequently, two separate tables of data are presented identifying the parameters of each case:

Parameters – BASE		**Reference PF Hard Coal without Capture**	**Base Conservative Hard Coal Oxy-fuel PF Power Plant**
Net Electricity Output	MWe	736	568
HP Turbine Steam Inlet Pressure	Bara	280	280
HP Turbine Inlet Temperature	ºC	600	600
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620
Net Full Load Plant Efficiency	% LHV	46%	35.4% 35.4-35.5
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.759	0.986 0.983-0.986
CO_2 Capture Rate	%	-	90
CO_2 Captured	t/MWh	-	0.887 0.885-0.887

Parameters – OPTI		**Reference PF Hard Coal without Capture**	**OPTI Hard Coal Oxy-fuel PF Power Plant**
Net Electricity Output	MWe	600	480
HP Turbine Steam Inlet Pressure	Bara	280	280
HP Turbine Inlet Temperature	ºC	600	600
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620
Net Full Load Plant Efficiency	% LHV	46%	36.3% 35.4-37%

Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.759	0.961 0.943-0.986
CO_2 Capture Rate	%	–	90
CO_2 Captured	t/MWh	–	0.865 0.849-0.887

With respect to the design of both hard coal oxy-fuel power plants, the following can be stated:

- Both oxy-fuel power plants employ cryogenic air separation plants
- Both plants have flue gas recirculation and can operate in either oxy-fuel or air firing conditions
- Both power plants contemplate a full-scale flue gas desulphurisation (FGD) plant. In some OPTI power plant concepts, sulphur is separated during the CO_2 liquefaction process that could result in additional minor cost and net-efficiency benefits.
- The principal additional energy requirements leading to a 9%-11% real drop in the power plant efficiency when referenced to power plant without capture are related to:
    - Cryogenic air separation processes
    - Recycle fan
    - CO_2 compression.

The determination of the energy requirement for the cryogenic air separation process is a subject under considerable discussion, as some manufacturers claim that improvements can easily be achieved that will result in a higher overall plant efficiency. However, the cost data for such concepts were not available for this study.

The economics of the BASE and OPTI plants are shown in the following two tables:

Economics		**Reference PF Hard Coal without Capture**			**BASE Conservative Hard Coal Oxy-fuel PF Power Plant**		
Performance Data							
Power plant capacity	MWe	736			568		
Investment Cost							
EPC cost	mill €	1,150			1,889 1,770-2,096		
EPC cost, net	€/kW	1,562.5			3,325 3,116-3,691		
Owner's Cost (including contingencies)	% EPC	10			10		
Total investment cost	mill €	1,265			2,077 1,947-2,306		
Fuel cost	€/GJ (LHV)	Low 2.0	Mid 2.4	High 2.9	Low 2.0	Mid 2.4	High 2.9

Operating Cost			
Fixed O&M	mill €/year	26.2	31.8 26.1-37.5
Variable O&M	€/MWh	1	1.55 1.4-1.7
Low Fuel Cost (€2.0/GJ)			
Levelised CAPEX	€/MWh	19.1 19.0-19.1	40.7 38.1-45.2
Levelised O&M	€/MWh	7.1	11.2 9.3-13.0
Levelised Fuel Cost	€/MWh	18.3	23.8 23.7-23.8
Levelised Electricity Cost (LCOE)	€/MWh	**44.6** **44.4-44.6**	71.3-**81.9**
CO_2 Avoidance Cost	€/t CO_2	–	40.5-**56.6**
Middle Fuel Cost (€2.4/GJ)			
Levelised CAPEX	€/MWh	19 19.0-19.1	40.7 38.1-45.2
Levelised O&M	€/MWh	7.1	11.2 9.3-13.0
Levelised Fuel Cost	€/MWh	22.0	28.6 28.5-28.6
Levelised Electricity Cost (LCOE)	€/MWh	**48.2** **48.1-48.3**	76.0-**86.7**
CO_2 Avoidance Cost	€/t CO_2	–	42.1-**58.2**
High Fuel Cost (€2.9/GJ)			
Levelised CAPEX	€/MWh	19 19.0-19.1	40.7 38.1-45.2
Levelised O&M	€/MWh	7.1	11.2 9.3-13.0
Levelised Fuel Cost	€/MWh	26.6	34.5 34.4-34.5
Levelised Electricity Cost (LCOE)	€/MWh	**52.8** **52.7-52.8**	82.0-**92.6**
CO_2 Avoidance Cost	€/t CO_2	–	44.2-**60.2**

Zep Zero emissions platform

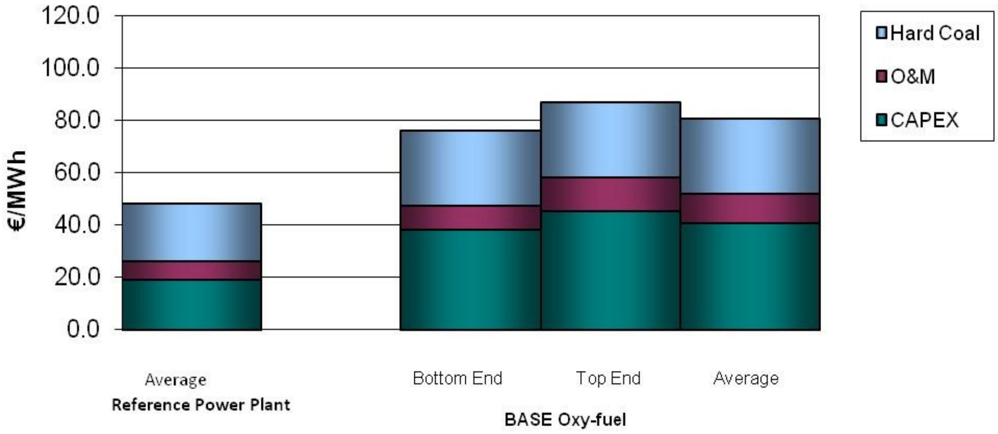
Economics		Reference PF Hard Coal without Capture	OPTI Hard Coal Oxy-fuel PF Power Plant
Performance Data			
Power plant capacity	MWe	600	480
Investment Cost			
EPC cost	mill €	729	1,056 989-1,132
EPC cost, net	€/kW	1,215.2	2,200 2,060-2,359
Owner's Cost (including contingencies)	% EPC	15	15
Total investment cost	mill €	839	1,214 1,137-1,302
Fuel cost	€/GJ (LHV)	Low / Mid / High 2.0 / 2.4 / 2.9	Low / Mid / High 2.0 / 2.4 / 2.9
Operating Cost			
Fixed O&M	mill €/year	15.3	23.0 22.1-24.0
Variable O&M	€/MWh	1.1	1.55 1.4-1.7
Low Fuel Cost (€2.0/GJ)			
Levelised CAPEX	€/MWh	15.5	28.1 26.3-30.2
Levelised O&M	€/MWh	5.2	9.9 9.3-10.4
Levelised Fuel Cost	€/MWh	18.3	23.2 22.8-23.8
Levelised Electricity Cost (LCOE)	€/MWh	**39.1**	**58.5**-64.3
CO_2 Avoidance Cost	€/t CO_2	–	**28.5**-37.6
Middle Fuel Cost (€2.4/GJ)			
Levelised CAPEX	€/MWh	15.5	28.1 26.3-30.2
Levelised O&M	€/MWh	5.2	9.9 9.3-10.4
Levelised Fuel Cost	€/MWh	22.0	27.9 27.3-28.6
Levelised Electricity Cost (LCOE)	€/MWh	**42.8**	**63.0**-69.1
CO_2 Avoidance Cost	€/t CO_2	–	**29.9**-39.3

High Fuel Cost (€2.9/GJ)			
Levelised CAPEX	€/MWh	15.5	28.1 26.3-30.2
Levelised O&M	€/MWh	5.2	9.9 9.3-10.4
Levelised Fuel Cost	€/MWh	26.6	33.7 33.0-34.5
Levelised Electricity Cost (LCOE)	€/MWh	**47.4**	**68.7**-75.1
CO_2 Avoidance Cost	€/t CO_2	–	**31.6**-41.4

The differences in capital costs within each band of the BASE and OPTI plant designs are in the range of 14%-18%, which are probably due to the difference in the costs assumed for the air separation plant and the CO_2 purification and compression islands. For the purposes of this study, and in order to be consistent with the approach adopted for the other technologies, the values for oxy-fuel for the BASE and OPTI cases used in the comparative graphs are identified in bold text.

However, in both cases, the efficiency penalties with respect to the reference plants are similar, being between 9 and 10.5 points, probably due to the fact that both specify a cryogenic air separation plant. There was also a considerable spread in fixed O&M costs, ranging from €46 to €66/KW_{net} per year in the BASE plant design, again attributable to uncertainties in the process and differing assumptions in the maintenance requirements of the air separation plant and CO_2 purification and compression islands. However, the variable O&M costs are similar to those of the reference power plants without capture, mainly due to the fact that oxy-fuel technology does not require additional chemicals and cooling water etc.

In summary, Figures 11 and 12 identify the LCOE and CO_2 avoidance costs considered for the BASE and OPTI hard-coal PF oxy-fired power plant, based on the middle fuel cost of €2.4/GJ.



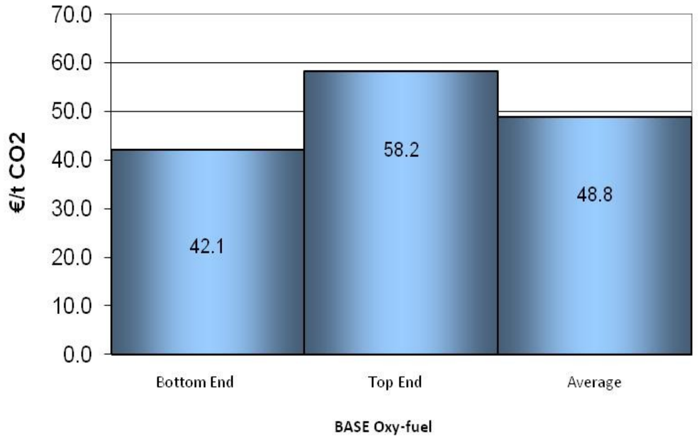


Figure 11: LCOE and CO_2 avoidance costs for BASE hard coal-fired power plants with oxy-fuel capture

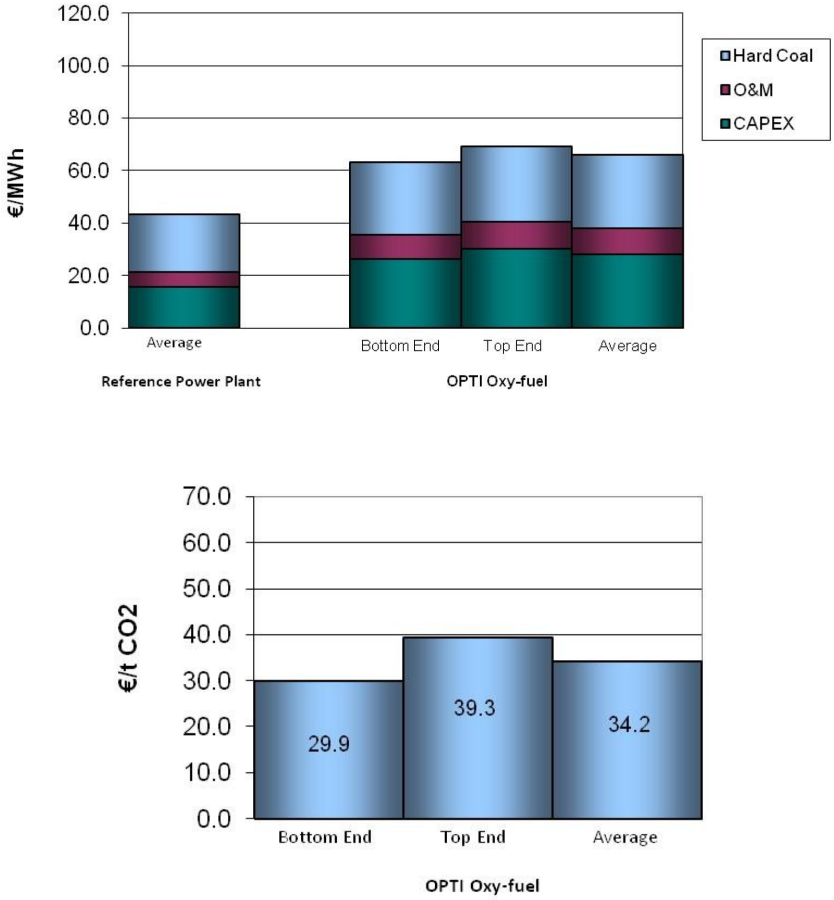
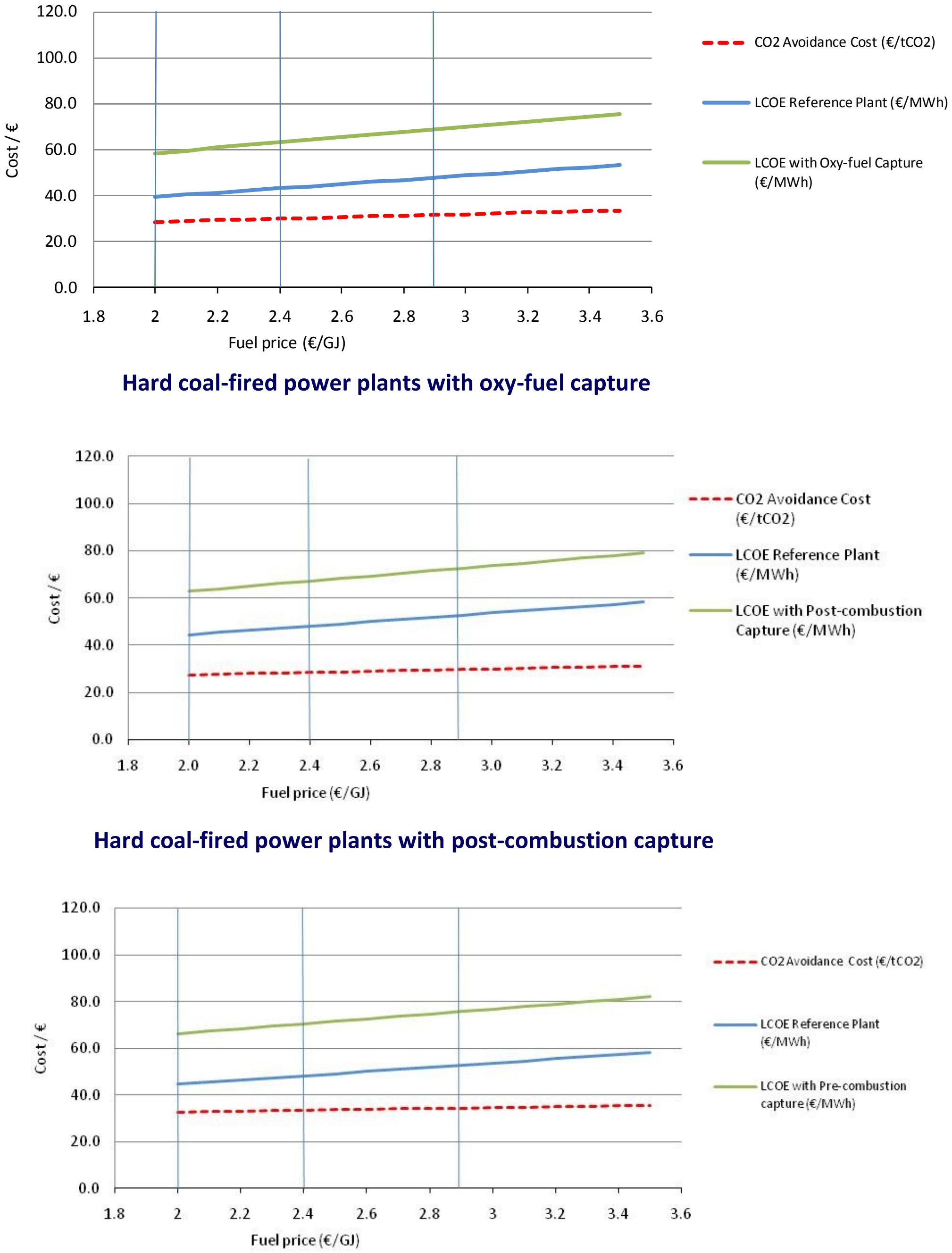


Figure 12: LCOE and CO_2 avoidance costs for OPTI hard coal-fired power plants with oxy-fuel capture

The impact of varying fuel costs for the three capture technologies for hard coal simply displaces the graphs in a vertical direction (Figure 13). The steeper dependence on fuel costs of the oxy-fuel power plant with respect to the other two capture technologies is, in general, due to the lower plant efficiency identified for this power plant concept. These graphs are based on OPTI power plant costs.



Hard coal-fired power plants with oxy-fuel capture

Hard coal-fired power plants with post-combustion capture

Hard coal IGCC power plants with pre-combustion capture

Figure 13: Dependence on the coal price for all three capture technologies

3.2 Lignite

The LCOE and CO_2 avoidance costs have been calculated for the following early commercial CO_2 capture technologies that could enter into operation in the early 2020s:

- BASE lignite-fired PF ultra supercritical (280 bar 600/620ºC steam cycle) power plant with post-combustion capture based on advanced amines
- BASE lignite-fired 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, and lignite pre-dryer).
- OPTI lignite oxy-fuel PF power plant with ultra supercritical steam conditions (280 bar 600/620ºC steam cycle) and lignite pre-dryer.

As previously stated, power plant costs are referenced to the second quarter of 2009 and the lignite fuel price is €1.39/GJ. The following costs have been determined for each of the cases studied:

		Levelised Electricity Costs (LCOE) €/MWh	**CO_2 Avoidance Cost €/t CO_2**
Reference Case – No Capture	State-of-the-art	43.7	–
Lignite PF Post-Combustion Capture	BASE Early Commercial	75.2	38.9
	OPTI Early Commercial		
Lignite IGCC with Pre-Combustion Capture	(Reference) BASE Early Commercial	(45.5) 67.4	29.9
	OPTI Early Commercial		
Lignite PF Oxy-fuel Capture	BASE Early Commercial		
	(Ref Plant) OPTI Early Commercial	(35.6) 49.5	19.3

Figures 14 and 15 show the data from the above table:

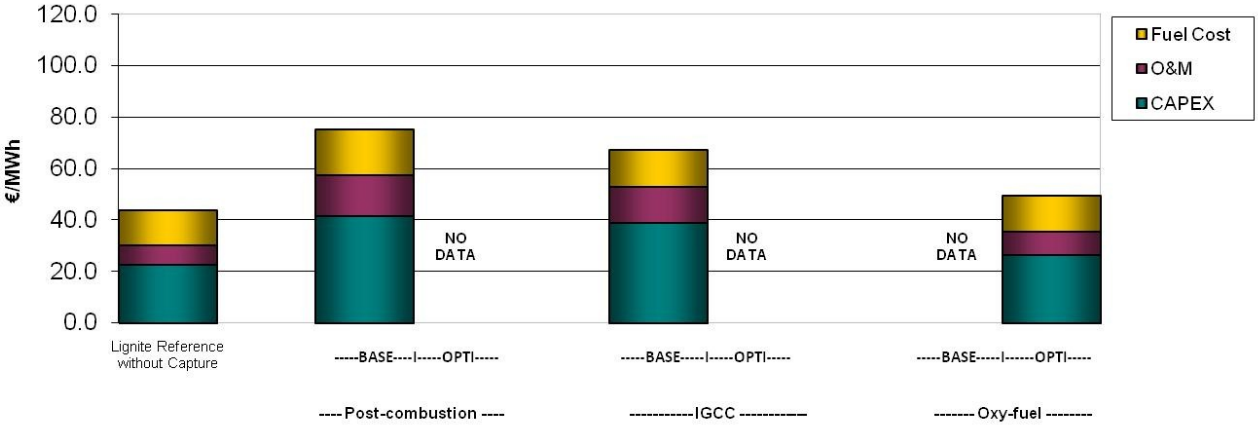


Figure 14: LCOE for lignite-fired power plants with CO_2 capture

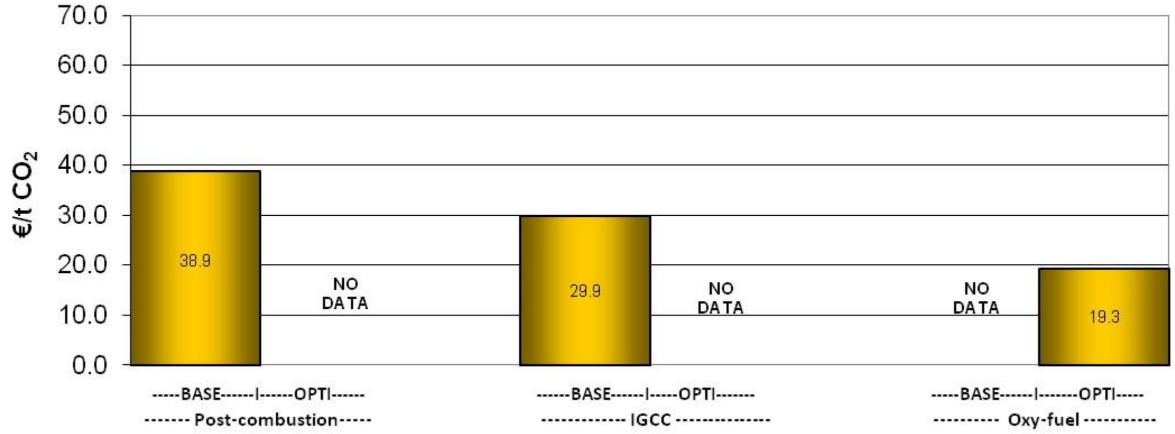


Figure 15: CO_2 avoidance costs for lignite-fired power plants with CO_2 capture

From this sparse dataset, it is not credible to draw any conclusions. Comparing the two BASE plant options, the indication is that the IGCC power plant with capture is significantly more economical than the post-combustion option. However, it must be taken into consideration that the post-combustion option is the only case where pre-drying of the lignite is not included in both the reference and capture plant. However, the results do suggest the need for further studies on lignite-fired power plants and the need to demonstrate such plants as they could prove to be competitive.

In the following sub-sections, details are given of each of the three concepts studied:

3.2.1 Lignite-fired PF coal-fired power plant with post-combustion capture

As with the hard coal case, a CO_2 capture plant and a compression island were integrated into the reference lignite-fired PF coal power plant. The post-combustion capture plant is again based on an advanced amine.

As with the hard coal power plant case, the addition of the capture plant and compression island caused the net efficiency and power output to drop, as shown in the following table:

Parameters		Reference PF Lignite without Capture	PF Lignite with Post-Combustion Capture
Net Electricity Output	MWe	989	759
HP Turbine Steam Inlet Pressure	Bara	280	280
HP Turbine Inlet Temperature	ºC	600	600
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620
Net Full Load Plant Efficiency	% LHV	43%	33%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.930	1.212
CO_2 Capture Rate	%	–	90
CO_2 Captured	t/MWh	–	1.091

The lignite PF power plant with post-combustion capture has the following characteristics:

- A design representative of a BASE early commercial power plant entering into operation around 2020, with the capture plant employing a commercially available advanced amine.
- Neither the reference power plant nor the power plant with capture include pre-drying of the lignite.
- The capture power plant consists of four CO_2 capture trains mounted in parallel and a six-train CO_2 compression plant.
- Heat integration is included in the power plant design with capture.
- The steam turbine design has not been modified to reflect large steam extraction for the capture power plant. Steam extraction for an overflow line is considered, employing a valve to hold pressure during part load operation.
- The main additional energy requirements leading to a 10% real drop in the power plant efficiency are identified as:
  - The steam extraction taken from between the IP and LP turbine for the reboiler of the capture power plant
  - CO_2 compressor electrical drive
  - Additional Induced Draft (ID) fan.

The power plant cost for the lignite power plant with capture can therefore be considered to be very conservative, being representative of a BASE early commercial power plant. The economics are shown in the following table:

Economics		Reference PF Lignite without Capture	PF Lignite with Post-Combustion Capture
Performance Data			
Power plant capacity	MWe	989	759
Investment Cost			
EPC cost	mill €	1,680	2,360
EPC cost, net	€/kW	1,699	3,109
Owner's Cost (including contingencies)	% EPC	20	20
Total investment cost	mill €	2,016	2,832
Fuel cost	€/GJ (LHV)	1.39	1.39
Operating Cost			
Fixed O&M	mill €/year	37.2	51.6
Variable O&M	€/MWh	1	3.8
Levelised CAPEX	€/MWh	22.7	41.5
Levelised O&M	€/MWh	7.4	15.9
Levelised Fuel Cost	€/MWh	13.6	17.8
Levelised Electricity Cost (LCOE)	€/MWh	**43.7**	**75.2**
CO_2 Avoidance Cost	€/t CO_2	–	**38.9**

It must be remembered that the lignite power plant with capture is a BASE power plant design which does not include pre-drying of the lignite. As the reference power plant without capture also does not include pre-drying, this variable is not included in the economics. A reduction in costs would be expected with the incorporation of pre-drying and modification to the steam turbine.

The fixed and variable O&M costs for a lignite-fired post-combustion capture power plant increase in a similar way to those of a hard coal-fired power plant with capture, as would be expected. The increase of 39% in fixed O&M costs takes into account the maintenance of the capture plant as well as the additional labour costs. These costs would be expected to reduce as the capture plants become a standard part of the power plant. With respect to the variable O&M costs, they more than triple for the reference power plant without capture due to the additional chemical costs, cooling water fees and waste disposal costs. As with the hard coal case, future solvent costs and quality of waste materials are currently “unknowns”, resulting in an uncertainty in this cost.

Figure 16 identifies the LCOE and CO_2 avoidance costs for a BASE lignite PF power plant with post-combustion capture:

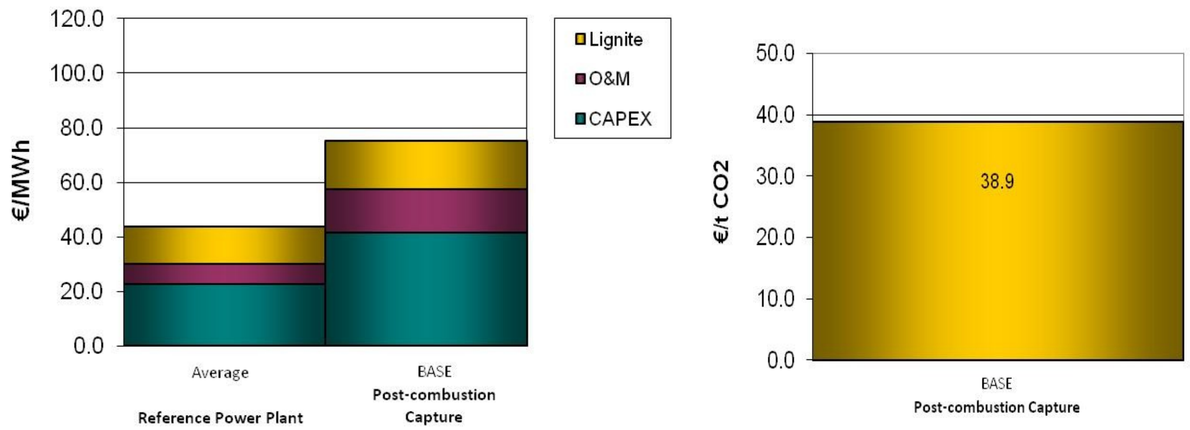


Figure 16: LCOE and CO_2 avoidance costs for lignite-fired power plants with post-combustion capture

3.2.2 Lignite IGCC with pre-combustion capture

As with the hard coal case, the reference power plant selected for this case was a state-of-the-art PF coal-fired power plant. The design parameters of the lignite IGCC power plant with capture and the reference power plant are shown in the following table:

Parameters		**Reference PF Lignite without Capture**	**IGCC – Full Water Quench Design; Sour CO-Shift, H2Syngas Saturation and Dilution**
Net Electricity Output	MWe	1100	900
Net Full Load Plant Efficiency	% LHV	48%	40%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.833	1,000
CO_2 Capture Rate	%	–	90
CO_2 Captured	t/MWh	–	0.900

With respect to the design of the IGCC power plant with pre-combustion CO_2 capture, the following can be assumed:

- A design representative of a BASE early commercial power plant entering into operation in 2020
- The use of a conventional cryogenic air separation plant
- Pre-drying of the lignite fuel (the same as the reference PF power plant)
- An entrained pressurised gasifier with full water quench of 1,000 MWt
- No Air Side Integration
- Two-stage sour CO-Shift
- CO_2 separation with a physical solvent such as Rectisol or Selexol
- Claus tail gas treatment is included
- Resulting H_2 rich syngas is saturated and diluted before combustion
- CO_2 compressor electrical drive.

The economics are shown in the following table:

Economics		**Reference PF Lignite without Capture**	**IGCC – Full Water Quench Design; Sour CO-Shift, H2Syngas Saturation and Dilution**
Performance Data			
Power plant capacity	MWe	1,100	900
Investment Cost			
EPC cost	mill €	2,017	2,620
EPC cost, net	€/kW	1,834	2,911
Owner's Cost (including contingencies)	% EPC	20	20
Total investment cost	mill €	2,420	3,144
Fuel cost	€/GJ (LHV)	1.39	1.39
Operating Cost			
Fixed O&M	mill €/year	50.4	65.5
Variable O&M	€/MWh	1	1.5
Levelised CAPEX	€/MWh	24.5	38.8
Levelised O&M	€/MWh	8.8	13.9
Levelised Fuel Cost	€/MWh	12.2	14.6
Levelised Electricity Cost (LCOE)	€/MWh	**45.5**	**67.4**
CO_2 Avoidance Cost	€/t CO_2	–	**29.9**

As with the hard coal case, the calculated CO_2 avoidance cost is referenced to a PF coal-fired power plant and not an IGCC without capture. This figure can therefore appear higher than those published in other studies.

The LCOE obtained for the lignite-fired IGCC power plant with pre-combustion capture is considerably lower than that for the post-combustion capture option. However, unlike the post-combustion power plant, pre-drying of the lignite is included in both the reference plant and the plant with capture. The lignite IGCC power plant is considered to be a BASE early commercial power plant, although its design may be considered to be slightly more ambitious than the post-combustion plant.

Compared to the reference PF power plant, the LCOE of the lignite IGCC with CO_2 capture is predicted to be ~48% more expensive than the lignite PF ultra supercritical power plant without capture.

In summary, Figure 17 identifies the LCOE and CO_2 avoidance costs for a BASE lignite-fired IGCC with pre-combustion capture and pre-drying of the lignite:

Rue du Trône 61
1050 Brussels, Belgium
info@zero-emissionplatform.eu
www.zeroemissionsplatform.eu

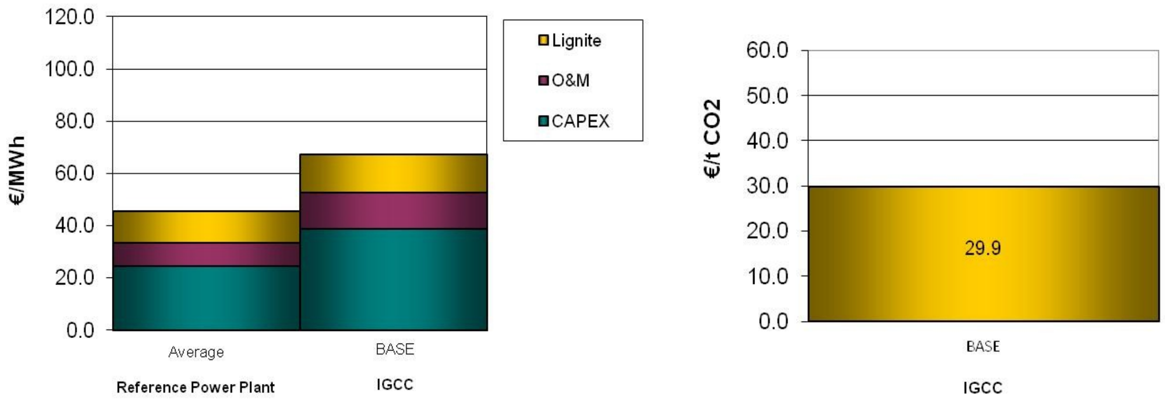


Figure 17: LCOE and CO_2 avoidance costs for lignite-fired IGCC power plants with pre-combustion capture

3.2.3 Lignite oxy-fuel PF power plant

The studies concerning the lignite PF oxy-fuel power plant were again based around a state-of-the-art ultra supercritical steam cycle of 600/620ºC, 280 bar. In this case, it must be noted that both the reference power plant and lignite-fired oxy-fuel power plant concept include pre-drying of the lignite.

The parameters of the power plants are shown in the following table:

Parameters		Reference PF Hard Coal without Capture	Lignite Oxy-fuel PF Power Plant
Net Electricity Output	MWe	920	750
HP Turbine Steam Inlet Pressure	Bara	280	280
HP Turbine Inlet Temperature	ºC	600	600
IP Turbine Inlet Steam Reheat Temperature	ºC	620	620
Net Full Load Plant Efficiency	% LHV	49%	42%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	40	40
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.816	0.952
CO_2 Capture Rate	%	–	90
CO_2 Captured	t/MWh	–	0.857

Key aspects of the design of the lignite oxy-fired power plant include:

- Use of cryogenic air separation plant.
- Pre-drying of the lignite leads to an improvement in plant efficiency of 6%-7% for the reference power plant (42%-43% for large lignite plants without drying and 48%-49% with drier).
- Design has flue gas recirculation and can operate in both oxy-fuel and air firing conditions.

- The sulphur is separated in an FGD plant.
- The principal additional energy requirements that result in a 7% real drop in the power plant efficiency when referenced to power plant without capture are due to:
  - Cryogenic air separation processes
  - Recycle fan
  - CO_2 compression.

This design is considered to be representative of an OPTI early commercial power plant and the economics are as follows:

Economics		**Reference PF Lignite without Capture**	**Lignite Oxy-fuel PF Power Plant**
Performance Data			
Power plant capacity	MWe	920	750
Investment Cost			
EPC cost	mill €	1,167	1,488
EPC cost, net	€/kW	1,268	1,983
Owner's Cost (including contingencies)	% EPC	20	20
Total investment cost	mill €	1,400	1,785
Fuel cost	€/GJ (LHV)	1.39	1.39
Operating Cost			
Fixed O&M	mill €/year	30	33.7
Variable O&M	€/MWh	1.09	1.36
Levelised CAPEX	€/MWh	16.9	26.5
Levelised O&M	€/MWh	6.7	9.1
Levelised Fuel Cost	€/MWh	12.0	13.9
Levelised Electricity Cost (LCOE)	€/MWh	**35.6**	**49.5**
CO_2 Avoidance Cost	€/t CO_2	–	**19.3**

N.B. The supplier of the data accepts that the values are ambitious and on the low side, which impacts on the LCOE and raises the question whether this can be compared directly with other LCOE results in this study. However, this impact is somewhat negated for the CO_2 avoidance costs, as the basis for both the reference plant and the OPTI plant are the same.

In this study, the inclusion of oxy-fuel technology increases the levelised specific investment by €770/KW_{net} from that of the reference power plant, mainly due to the addition of the cryogenic ASU and the CO_2 compression and conditioning equipment. The fixed O&M costs increase from €32.6 to €44.9/KW_{net} per year, which is attributable to the additional plant components. However, as with the hard coal oxy-fuel, the variable O&M costs do not increase significantly over those of the reference plant, as oxy-fuel technology does not require additional chemicals and cooling water etc.

In summary, Figure 18 identifies the LCOE and CO_2 avoidance costs for an OPTI lignite PF oxy-fired power plant.

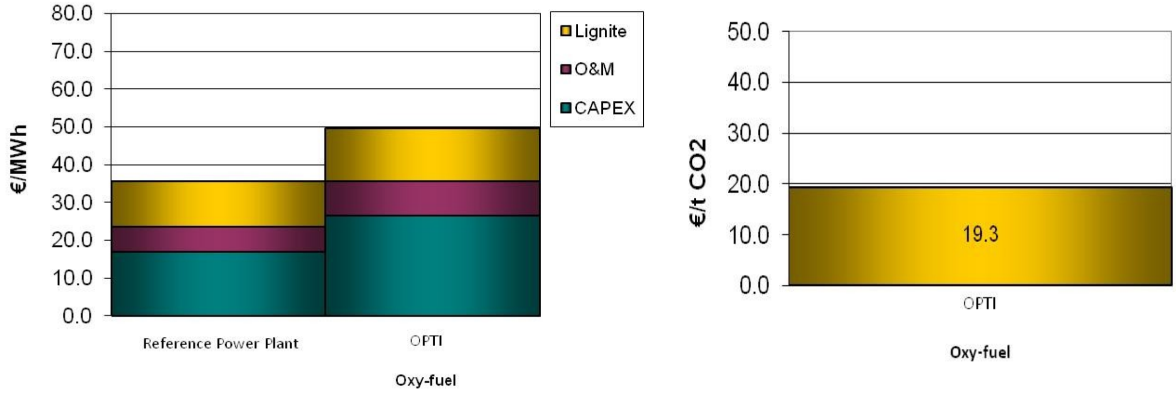


Figure 18: LCOE and CO_2 avoidance costs for lignite-fired power plants with oxy-fuel capture

3.3 Natural gas

The LCOE and CO_2 avoidance costs have been calculated for the following early commercial CO_2 capture technologies that would enter into operation in the early 2020s:

- Natural gas-fired single-shaft F-class CCGT with post-combustion capture, based on an advanced amine.

As the costs for natural gas have an important impact on the final calculated costs for this plant, the following three fuel prices have been considered. The wide range selected demonstrates the future uncertainty in the natural gas fuel price and the possible impact of shale gas on future prices.

Fuel Costs	Low	Middle	High
Natural Gas – €/GJ	4.5	8.0	11.0

The results obtained are shown in the following table:

		Levelised Electricity Costs (LCOE) €/MWh	CO_2 Avoidance Cost €/t CO_2
Low Fuel Cost €4.5/GJ			
BASE Reference Case – No Capture	State-of-the-art	47.2	-
Natural Gas CCGT Post-Combustion Capture	BASE Early Commercial	**73.7**	**91.8**
OPTI Reference Case – No Capture	State-of-the-art	45.5	
Natural Gas CCGT Post-Combustion Capture	OPTI Early Commercial	**64.0**	**65.9**
Middle Fuel Cost €8.0/GJ			
BASE Reference Case – No Capture	State-of-the-art	71.9	–

Natural Gas CCGT Post-Combustion Capture	BASE Early Commercial	**103.5**	**109.7**
OPTI Reference Case – No Capture	State-of-the-art	69.3	
Natural Gas CCGT Post-Combustion Capture	OPTI Early Commercial	**91.5**	**79.0**
High Fuel Cost €11.0/GJ			
BASE Reference Case – No Capture	State-of-the-art	93.0	–
Natural Gas CCGT Post-Combustion Capture	BASE Early Commercial	**129.0**	**125.0**
OPTI Reference Case – No Capture	State-of-the-art	89.7	
Natural Gas CCGT Post-Combustion Capture	OPTI Early Commercial	**115.1**	**90.2**

As stated previously, the above table demonstrates that LCOE and capture costs for natural gas-fired CCGT plants with capture are heavily influenced by the fuel and CO_2 capture costs.

Figures 19 and 20 display the results for the middle gas price of €8/GJ:

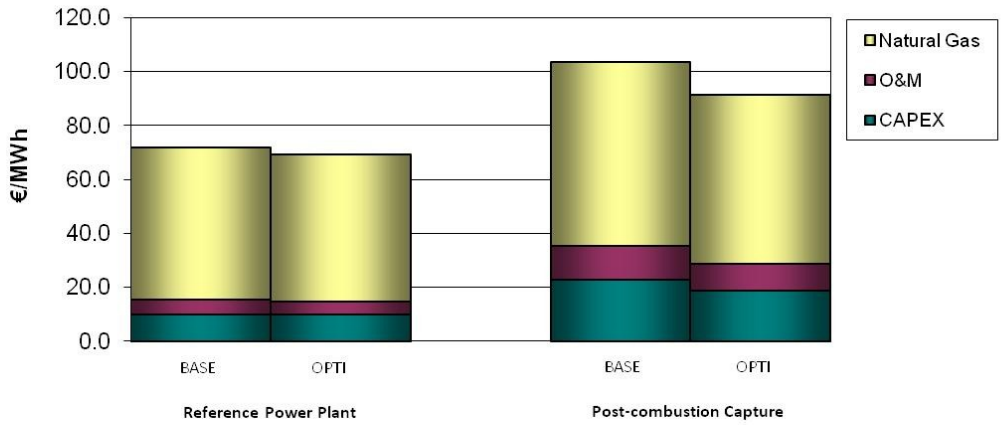


Figure 19: LCOE for natural gas-fired power plants with CO_2 capture

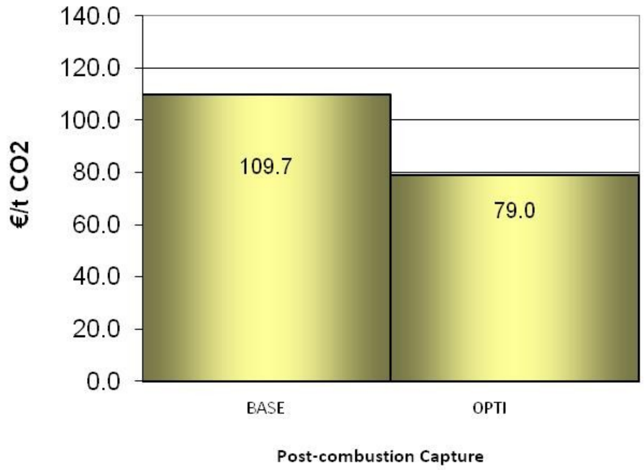


Figure 20: CO_2 avoidance costs for natural gas-fired power plants with CO_2 capture

These results highlight the importance of fuel costs in the natural gas case and this dependence is also shown in Figures 21 and 22 below (using OPTI plant costs):

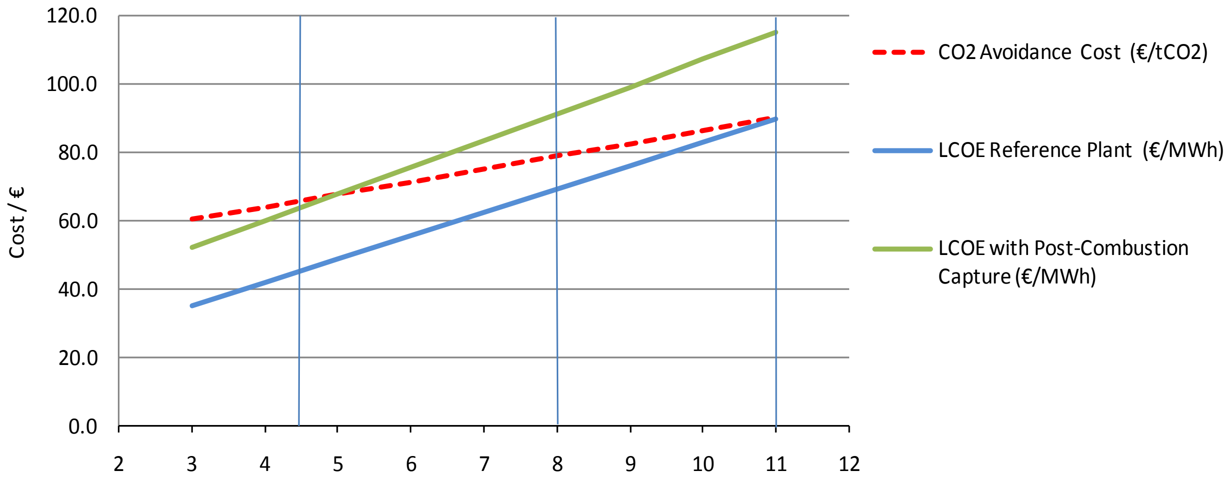


Figure 21: Dependence on the natural gas price for post-combustion capture (OPTI power plant)

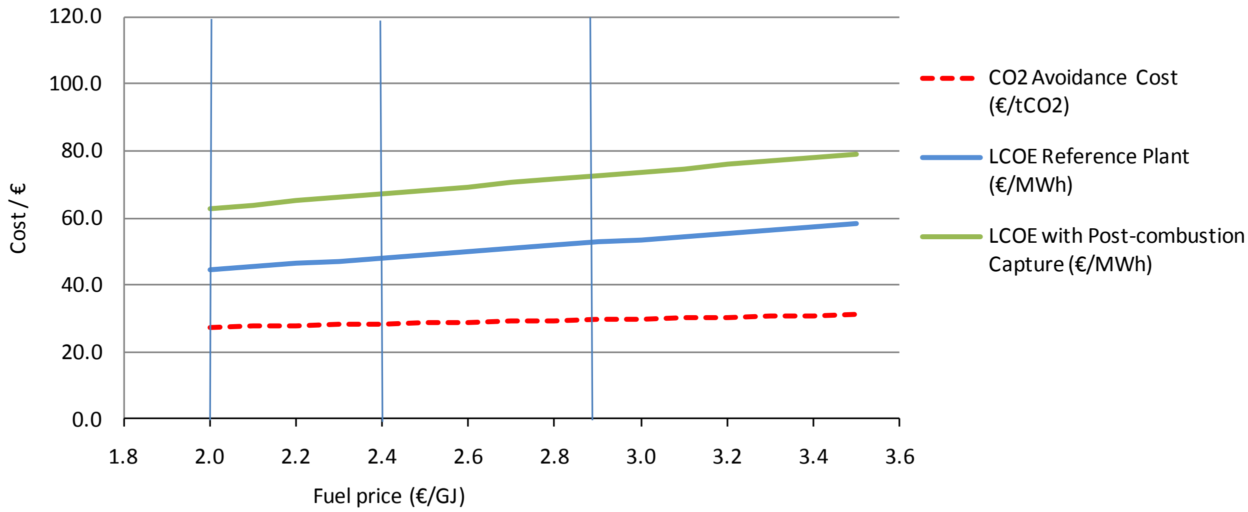


Figure 22: Dependence on the coal price for post-combustion capture (OPTI power plant)

Predicting future natural gas prices for Europe is not an exact science, as the predicted future impact of shale gas on natural gas prices varies from one source to the other. When comparing published CO_2 capture costs, it is therefore critical that the fuel cost used in the calculation is taken into consideration.

The CO_2 avoidance cost for natural gas-fired power plants is higher than for coal-fired power plants due to the fact that they are lower capital cost power plants. The fact that the CO_2 is more diluted in the flue gas (3%-5% instead of 12%-15%) does not improve the situation as a larger quantity of flue gas has to be treated for a given volume of CO_2 in the CCGT option. The plants analysed do not include new future options such as flue gas recirculation, or different capture options which seem to be required to drive down future CO_2 capture costs.

3.3.1 Natural gas combined cycle with post-combustion capture

Two separate cases have been studied for the natural gas-fired CCGT with post-combustion capture. The first addressed the addition and integration of a CO_2 capture plant and compression island to a current state-of-the-art 2009 F-class single-shaft 50Hz CCGT producing 420 MWe at an efficiency of 58% (LHV) (which is the reference case without capture and compression). Very little integration is foreseen in this design and the power plant concept is for a BASE early commercial capture power plant.

The design details are given in the following table:

Parameters		**Single-shaft F-class CCGT**	**Single-shaft F-class CCGT with Post-Combustion: Advanced Amine**
Net Electricity Output	MWe	420	350
HP Turbine Steam Inlet Pressure	Bara	113.8/27.7/3.99	113.8/27.7/3.99
HP Turbine Inlet Temperature	ºC	549	549
IP Turbine Inlet Steam Reheat Temperature	ºC	549	549
Net Full Load Plant Efficiency	% LHV	58%	48%
Plant Load Factor	h/year	7,500	7,500

Plant Life	Year	25	25
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.347	0.419
CO_2 Capture Rate	%	–	86
CO_2 Captured	t/MWh	–	0.360

This study assumes a 10% real drop in plant efficiency owing to additional steam/electricity consumption required due to the installation of a larger flue gas fan, the compression of the CO_2 and the energy required by the stripper to separate the CO_2 from solvent. In this design for the power plant with capture, the steam turbine is assumed to maintain its efficiency, despite the extraction of steam for stripper operations.

The second case is an OPTI power plant, where the CO_2 capture plant and compression island is integrated into a more efficient CCGT power plant, with an efficiency of 60% (LHV) in combined cycle without the capture plant and compression island. In this concept, the drop in plant efficiency has been calculated to be eight percentage points.

The following table shows the design details of the OPTI power plant:

Parameters		**Advanced Single-shaft CCGT**	**Advanced Single-shaft CCGT with Post-Combustion: Advanced Amine**
Net Electricity Output	MWe	420	364
HP Turbine Steam Inlet Pressure	Bara	113.8/27.7/3.99	113.8/27.7/3.99
HP Turbine Inlet Temperature	ºC	549	549
IP Turbine Inlet Steam Reheat Temperature	ºC	549	549
Net Full Load Plant Efficiency	% LHV	60%	52%
Plant Load Factor	h/year	7,500	7,500
Plant Life	Year	25	25
CO_2 Emissions Calculated from Fuel Carbon Content	t/MWh	0.335	0.387
CO_2 Capture Rate	%	-	86
CO_2 Captured	t/MWh	-	0.332

The economics of the reference and capture case for the BASE plant are shown in the following table:

Economics		**Single-shaft F-class CCGT**	**Single-shaft F-class CCGT with Post-Combustion: Advanced Amine**
Performance Data			
Power plant capacity	MWe	420	350
Investment Cost			
EPC cost	mill €	300	582
EPC cost, net	€/kW	714	1,662
Owner's Cost (including contingencies)	% EPC	10	10
Total investment cost	mill €	330	640

		Low	Mid	High	Low	Mid	High
Fuel cost	€/GJ (LHV)	4.5	8.0	11.0	4.5	8.0	11.0
Operating Cost							
Fixed O&M	mill €/year	9			17.5		
Variable O&M	€/MWh	2			4		
Low Fuel Cost (€4.5/GJ)							
Levelised CAPEX	€/MWh	9.8			22.7		
Levelised O&M	€/MWh	5.8			12.6		
Levelised Fuel Cost	€/MWh	31.7			38.3		
Levelised Electricity Cost (LCOE)	€/MWh	**47.2**			**73.7**		
CO_2 Avoidance Cost	€/t CO2	–			**91.8**		
Middle Fuel Cost (€8.0/GJ)							
Levelised CAPEX	€/MWh	9.8			22.7		
Levelised O&M	€/MWh	5.8			12.6		
Levelised Fuel Cost	€/MWh	56.4			68.1		
Levelised Electricity Cost (LCOE)	€/MWh	**71.9**			**103.5**		
CO_2 Avoidance Cost	€/t CO_2	–			**109.7**		
High Fuel Cost (€11.0/GJ)							
Levelised CAPEX	€/MWh	9.8			22.7		
Levelised O&M	€/MWh	5.8			12.6		
Levelised Fuel Cost	€/MWh	77.5			93.6		
Levelised Electricity Cost (LCOE)	€/MWh	**93.0**			**129.0**		
CO_2 Avoidance Cost	€/t CO2	–			**125.0**		

The economics of the reference and capture case for the OPTI plant are shown in the following table:

Economics		**Advanced Single-shaft CCGT**	**Advanced Single-shaft CCGT with Post-Combustion: Advanced Amine**
Performance Data			
Power plant capacity	MWe	420	364
Investment Cost			
EPC cost	mill €	300	500
EPC cost, net	€/kW	714	1,374
Owner's Cost (including contingencies)	% EPC	10	10
Total investment cost	mill €	330	550

Fuel cost	€/GJ (LHV)	Low 4.5	Mid 8.0	High 11.0	Low 4.5	Mid 8.0	High 11.0
Operating Cost							
Fixed O&M	mill €/year	9			15.0		
Variable O&M	€/MWh	1.4			2.8		
Low Fuel Cost (€4.5/GJ)							
Levelised CAPEX	€/MWh	9.8			18.8		
Levelised O&M	€/MWh	5.1			9.8		
Levelised Fuel Cost	€/MWh	30.6			35.4		
Levelised Electricity Cost (LCOE)	€/MWh	**45.5**			**64.0**		
CO_2 Avoidance Cost	€/t CO_2	–			**65.9**		
Middle Fuel Cost (€8.0/GJ)							
Levelised CAPEX	€/MWh	9.8			18.8		
Levelised O&M	€/MWh	5.1			9.8		
Levelised Fuel Cost	€/MWh	54.5			62.9		
Levelised Electricity Cost (LCOE)	€/MWh	**69.3**			**91.5**		
CO_2 Avoidance Cost	€/t CO_2	–			**79.0**		
High Fuel Cost (€11.0/GJ)							
Levelised CAPEX	€/MWh	9.8			18.8		
Levelised O&M	€/MWh	5.1			9.8		
Levelised Fuel Cost	€/MWh	74.9			86.4		
Levelised Electricity Cost (LCOE)	€/MWh	**89.7**			**115.1**		
CO_2 Avoidance Cost	€/t CO_2	–			**90.2**		

As with the other post-combustion studies for other fuels, there is a considerable increase in the fixed and variable O&M costs, due to similar reasons. The doubling of the fixed O&M costs takes into account the maintenance of the capture plant as well as the additional labour costs. As the capture plant becomes more standard, the fixed O&M costs are expected to reduce, which is reflected in the OPTI power plant.

With respect to the variable O&M costs, they are foreseen to double, which is attributable to the additional chemical costs, cooling water fee and waste disposal costs. As with the other studies, there is considerable uncertainty regarding the future evolution of solvent and waste disposal costs, resulting in a considerable uncertainty in the variable O&M costs, although they are foreseen to drop in the OPTI power plant.

In summary, Figure 23 identifies the LCOE and CO_2 avoidance costs calculated for the natural gas-fired CCGT power plant with post-combustion capture, based on the medium fuel price of €8/GJ:

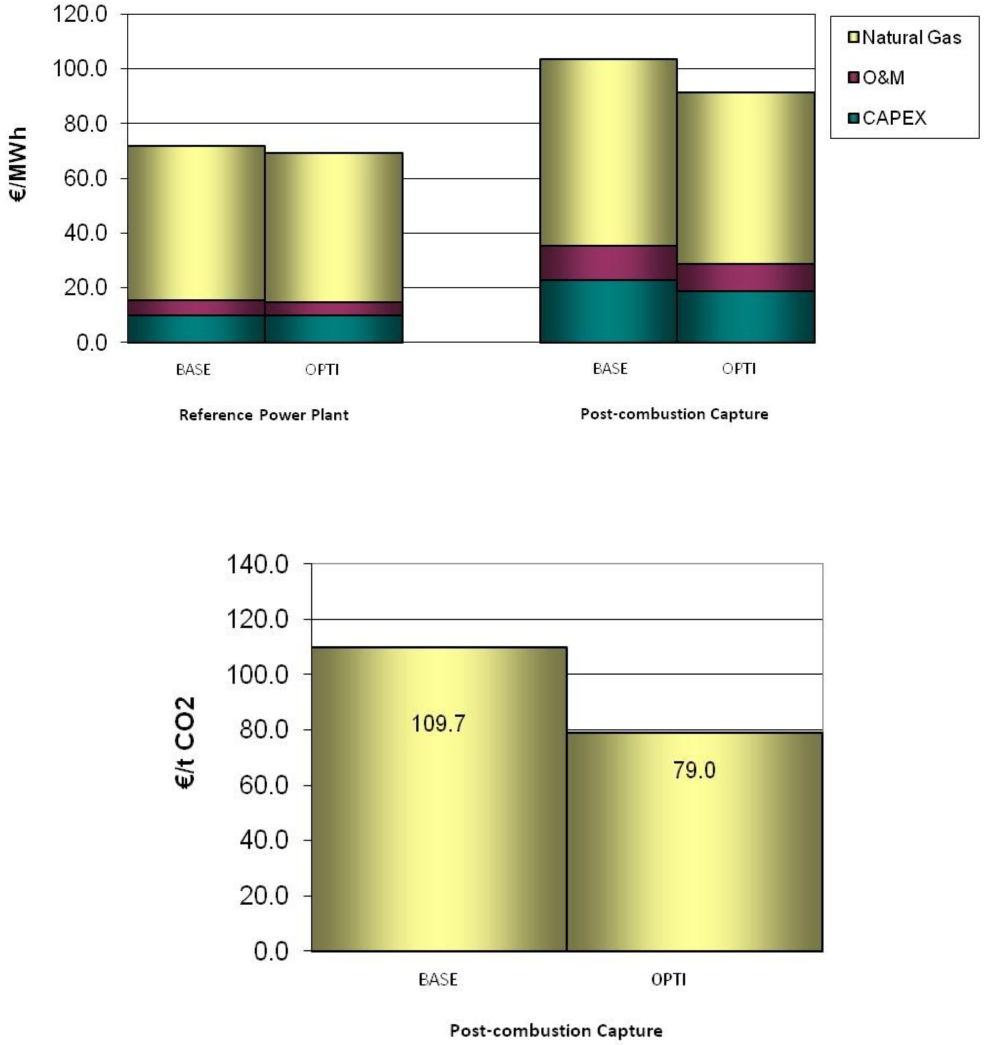


Figure 23: LCOE and CO_2 avoidance costs for natural gas-fired CC power plants with post-combustion capture

4 Comparison of ZEP Cost Estimates with Other Studies

Comparing ZEP cost estimates with those of other recently published reports is not straightforward as the boundary conditions are frequently different (see Figure 24 and Chapter 2 for those applied in this study).

		Hard coal plant			Natural gas plant			Lignite plant
Reference year of study	year	Second quarter 2009						
Economic lifetime	years	40			25			40
Depreciation	years	40			25			40
Fuel price	EUR/GJ (LHV)	2	2.4	2.9	4.5	8	11	1.39
Fuel price escalation	% per year	1.5%			1.5%			1.5%
Operating hours per year	hours per year	7,500			7,500			7,500
Standard Emission factor	t/MWh_{th}	0.344			0.210			0.402
Common Inputs								
O&M cost escalation		2%						
Debt/Equity ratio	%	50%						
Loan interest rate	%	6%						
Interest during construction	%	6%						
Return on Equity	%	12%						
Start of debt service		Commercial operation						
Tax rate	%	35%						
WACC		8%						
Discount rate	%	9%						

Figure 24: Financial and other boundary conditions used in this study

Differences in assumptions may include:

- Size of power plant
- Location of power plant
- Whether the costs refer to a BASE, OPTI, first-of-a-kind, or n^{th}-of-a-kind power plants that have assumed some future cost reduction
- Assumptions made on the level of plant integration between capture, compression and plant design
- CO_2 export conditions
- The year in which the study is referenced.

These can have a significant impact on the results, even though the fundamental data are similar. Without knowledge of the boundary conditions employed in other studies, cost comparisons are meaningless.

Recent studies carried out by the Global CCS Institute (GCCSI) and Harvard Kennedy School have tried to correlate previously published studies by levelising the costs to their particular boundary conditions in order to compare results. This report has taken a similar approach by extracting the maximum amount of technical and economic data possible from other studies, adjusting it to the second quarter of 2009 (with the cost correction curve shown on page 14) and recalculating the costs using the boundary conditions established in this study for the middle fuel costs.

Cost studies whose results have been analysed include:

- DECC Mott MacDonald: “UK Electricity Generation Costs Update”, June 2010

- Element Energy: "Potential for Application of CCS to UK Industry and Natural Gas Power Sectors", June 2010
- ENCAP: "Reference cases and guidelines for technology concepts", February 2008
- ENCAP: "Power systems evaluation and benchmarking. Public Version", February 2009
- EPRI Report 1013355, Holt, N. and G. Booras: "Updated Cost and Performance Estimates for Clean Coal Technologies including CO_2 Capture – 2006", 2007
- 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
- Harvard Kennedy School, Al Juaied, Whitmore: "Realistic Costs of Carbon Capture", July 2009
- McKinsey study: "Carbon Capture & Storage: Assessing the Economics", September 2008
- MIT: "The Future of Coal", 2007
- NETL: "Cost and Performance Baseline for Fossil Energy Plants", DOE/NETL-2007/1281, August 2007
- Rubin E., C. Chen, et al: "Cost and Performance of Fossil Fuel Power Plants with CO_2 Capture and Storage", 2008
- SFA Pacific, Inc: "Gasification – Critical Analysis of Technology, Economics, and Markets", 2007
- ZEP: "EU Demonstration Programme for CO_2 Capture and Storage (CCS): ZEP's Proposal", November 2008.

Figure 25 lists the boundary conditions that could be identified in the above studies:

		ZEP 2009	ZEP 2006	ENCAP	McKinsey	Harvard	MIT
Estimate Year		2009	2006	2004	2008	2008	2005
Economic life time (years)		25 / 40	25	25 / 40	40 (early commercial)	20 (FOAK)	20
Operating hours per year (hours)		7500	7500	7500	7500	7500	7500
Fuel price							
	Hard Coal	2 – 2.9 €/GJ	2.3 €/GJ	1.6 €/GJ	65€/tonne	$ 1.8 /MMBtu	$1-1.5/MMBtu
	Lignite	1.39 €/GJ	1.1 €/GJ	1.1 €/GJ	12€/tonne	$1.2 /MMBtu	
	Natural Gas	4.5 - 11 €/GJ	5.8 €/GJ	3.5 €/GJ		$8 /MMBtu	
Owner's cost							
	Hard Coal	10%	15%	15%		10%	
	Lignite	20%	20%	20%		10%	
	Natural Gas	10%	15%	15%		10%	
Discount rate		9%	9%				
WACC		8%	8%	8%	8%	10%	
		NETL/DOE	**EPRI**	**Rubin**	**SFA**	**Global CCS Institute**	**Mott McDonald**
Estimate Year		2006	2006	2005	2006	2009	2009
Economic life time (years)		20	30			30	35 / 45
Operating hours per year (hours)		7500	7000	7000	7500	7500	7800
Fuel price							
	Hard Coal	$1.8/MMBtu	$1.5/MMBtu	$1.2/MMBtu	$1.53/MMBtu	$7.10/GJ (Euro region)	1.39-2.64£/GJ
	Lignite						
	Natural Gas	$6.75/MMBtu	$6/MMBtu	$6/MMBtu	$6.35/MMBtu	$6.68/GJ (Euro region)	3.9-10.21£/GJ
Owner's cost		Not Included					
	Hard Coal					15%	
	Lignite					15%	
	Natural Gas					15%	
Discount rate						8.81%	10%
WACC							

Figure 25: Boundary conditions considered in other studies

* As detailed in the underlying report to ZEP's Strategic Research Agenda, "The final report from Working Group 1 – Power Plant and Carbon Dioxide Capture", October 2006

For the American studies that normally base their calculations considering the High Heating Value (HHV) instead of the Low Heating Value (LHV) used in ZEP and in other European studies, the HHV values have been converted using the following calculation:

Efficiency (LHV) = Efficiency (HHV) * (HHV/LHV)

For the hard coal cases, ZEP has assumed that the coal used in the American Studies corresponds to Illinois 6, with a coefficient HHV/LHV of 1.037. For the natural gas cases, the HHV/LHV ratio is assumed to be 1.108.

4.1 Hard coal

For the hard coal cases, a middle fuel price of €2.4/GJ has been assumed. For the purposes of comparison, the ZEP data used to make the comparison with other studies is the average cost value that is the boundary between the OPTI and the BASE power plant. In this simple comparison, no account has been made for the following:

- Difference in plant design/configuration for 50 Hz and 60 Hz designs
- The differing steam conditions used in the studies – they have simply been grouped into sub-critical, supercritical and ultra supercritical (including advanced supercritical). In this study, the USC conditions are 600/620ºC, 280 bar.

4.1.1 Hard coal PF coal-fired power plant with post-combustion capture

The following table shows the results published of the various studies:

	ZEP 2009	ZEP 2006	McKinsey	MIT			NETL/DOE		EPRI	Rubin	SFA	Global CCSI		Mott McDonald (FOAK)
	HARD COAL													
				SubC	SC	USC	SubC	SC				SC	USC	ASC
Levelised electricity cost (€/MWh)	70.3	57.5		54.7	51.5	49.2	79.6	76.9	62.2	59.0	62.0	162.2	142.1	156.31
CO2 avoidance cost (€/t CO2)	33.3	30.1	21-32	27.7	27.1	27.5	45.6	45.6	37.3	33.3	29.5	66.2	66.2	

N.B. The ZEP 2009 values are the Average LCOE and CO_2 avoidance cost. The data shown in red, the CO_2 avoidance cost for the GCCSI and NETL studies, and the LCOE for the Mott McDonald study are combined costs for capture, transport and storage, not just capture costs.

The relevant power plant costs and O&M data were extracted from each study, adjusted to second quarter of 2009 costs and calculated according to the methodology of this study. For the Rubin study, the fixed O&M cost was set at 1.5%, according to the recommendation of the IEA and the variable O&M cost set at a typical figure used in the ZEP study.

Figure 26 shows the adjusted results for the LCOE:

Rue du Trône 61
1050 Brussels, Belgium
info@zero-emissionplatform.eu
www.zeroemissionsplatform.eu

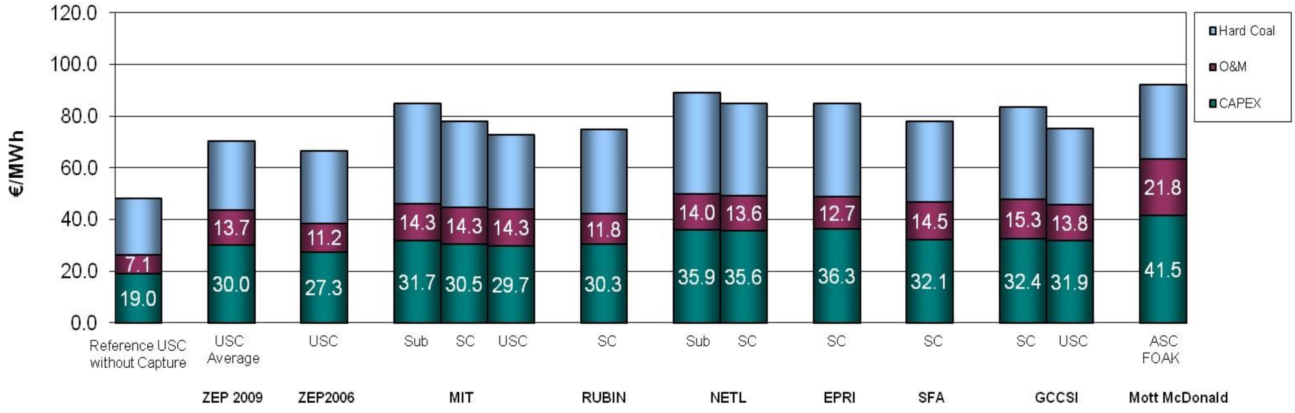


Figure 26: LCOE for hard coal-fired power plants with post-combustion capture

The CO_2 avoidance costs were determined by referencing the above figures to ZEP's reference power plant without CO_2 capture (Figure 27):

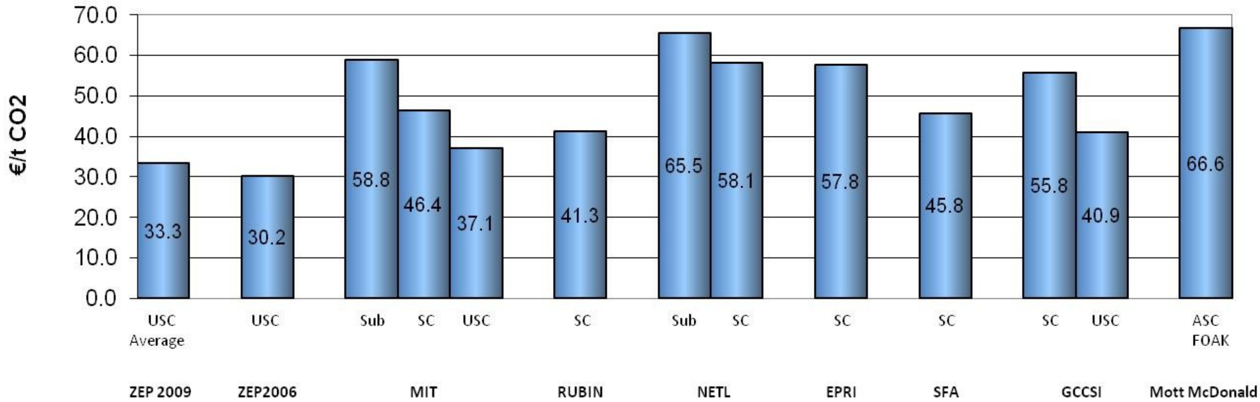


Figure 27: CO_2 avoidance costs for hard coal-fired power plants with post-combustion capture

Despite the simplifications assumed in this process, we believe the following observations can be made:

- In agreement with other studies, the CO_2 avoidance costs are higher for less efficient power plants with the subcritical steam power plants having the highest CO_2 avoidance costs. The state-of-the-art USC conditions identified in this study for Europe will lead to lower CO_2 avoidance costs.
- The levelised CAPEX of this study (€28.1-€31.8/MWh, average 30) and OPEX (€13.1-€14.5/MWh, average 13.7) are generally in good agreement with the figures determined in the GCCSI study, although the CAPEX is some 6% lower.
- In 2008, McKinsey published the following costs for an early commercial power plant:

McKinsey Published results 2008		Min	Max
CAPEX	€/t CO2	14	19
O&M cost	€/t CO2	5	7
Fuel cost	€/t CO2	2	6
CO2 avoidance cost	€/t CO2	25	32

The CO_2 avoidance costs calculated in this study are the following:

ZEP Study, 2009 data		Min	Max
Levelised CAPEX	€/t CO2	13.6	19.2
Levelised OPEX	€/t CO2	8.9	11.1
Levelised Fuel	€/t CO2	5.9	6.9
CO2 avoidance cost	€/t CO2	28.5	37.2

The higher costs in this study derive from higher OPEX and fuel costs. The McKinsey study assumed a plant efficiency with capture of 40%, which implies a 700ºC steam cycle and a resulting plant design some 2-4 points higher than that calculated in this study. This difference will impact on the both fuel and maintenance costs. As previously mentioned, there is a large degree of uncertainty in variable O&M costs for post-combustion capture power plants as future solvent, cooling water and disposal costs are “unknowns”.

4.1.2 Hard coal IGCC with pre-combustion capture

The following table shows the results of the various studies:

	ZEP 2009	ZEP 2006	ENCAP	McKinsey	Harvard	MIT	NETL/DOE	EPRI	Rubin	Global CCSI	Mott McDonald (FOAK)
	HARD COAL										
Levelised electricity cost (€/MWh)	74.7	57.9	49.4		135.3	45.9	71.2	58.0	48.2	151.1	162.36
CO2 avoidance cost (€/t CO2)	39.8	27.6	23.0	25-32	119.9	14.0	25.7	25.7	15.1	52.3	

N.B. The ZEP 2009 data are Average LCOE and CO_2 avoidance cost values. As with all the other cases, GCCSI and Mott McDonald data relate to the cost of capture, transport and storage combined, not just capture.

Applying the methodology and boundary conditions used in this study, Figures 28 and 29 were produced showing the adjusted LCOE and CO_2 avoidance costs:

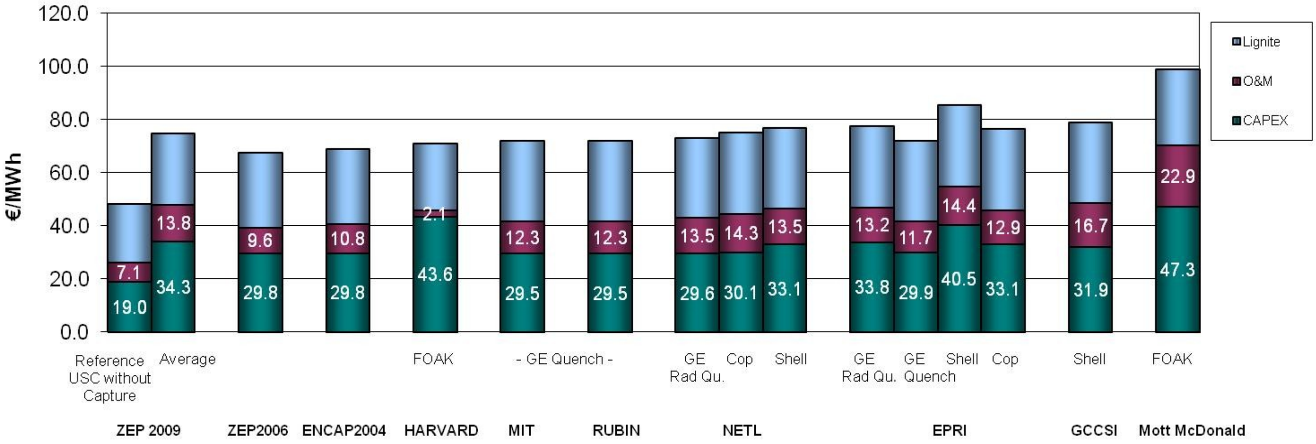


Figure 28: LCOE for hard coal-fired IGCC power plants with pre-combustion capture

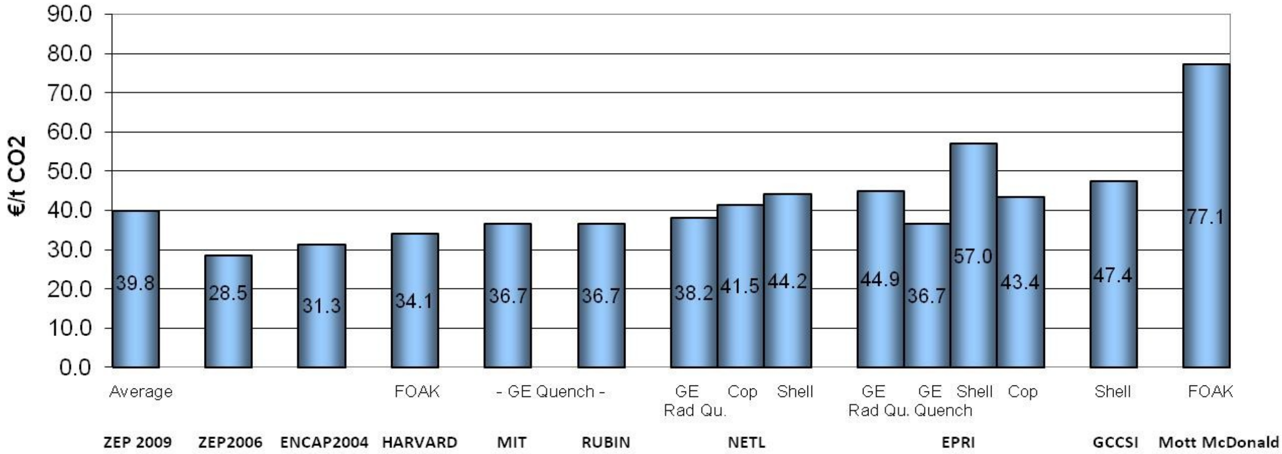


Figure 29: CO_2 avoidance costs for hard coal-fired IGCC power plants with pre-combustion capture

It must be noted that the CO_2 avoidance costs in this study were determined by referencing the IGCC power plants with capture to a PF power plant without capture, not an IGCC power plant without capture, so figures may differ from those of other studies. However, the following general conclusions can be made:

- The levelised capital and O&M costs obtained in this study are considerably higher than those of previous European studies (e.g. ZEP, ENCAP), being similar to those calculated by the Rubin, NETL and EPRI studies, but somewhat lower than the GCCSI study.
- In comparison with the GCCSI study, the capital costs are lower in a similar percentage to those of the hard coal post-combustion case and, again, the O&M costs are similar. One difference that may contribute to a different final result is that the plant efficiency in the GCCSI study is three points lower than that calculated by ZEP.

Zero emissions platform

4.1.3 Hard coal oxy-fuel PF power plant

The following table shows the results of the various studies:

	ZEP 2009	ZEP 2006	ENCAP	McKinsey	Global CCSI
	HARD COAL				
Levelised electricity cost (€/MWh)	65.9	57.9	40.3		144.8
CO2 avoidance cost (€/t CO2)	34.2	31.1	12.1	25-32	49.3

N.B. The ZEP 2009 data are Average LCOE and CO_2 avoidance cost values for an OPTI plant design – not previously cited in the report. As in all other cases, the Global CCS Institute (GCCSI) data relate to the cost of capture, transport and storage, not just the capture cost.

Applying the methodology and boundary conditions used in this study, Figures 30 and 31 were produced showing the adjusted LCOE and CO_2 avoidance costs for an OPTI oxy-fuel power plant:

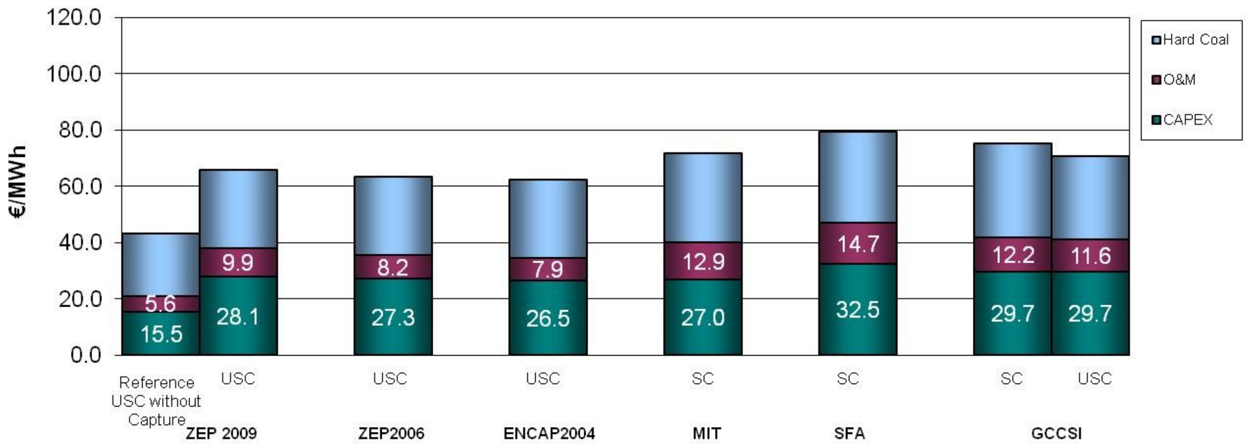


Figure 30: LCOE for hard coal-fired power plants with oxy-fuel capture

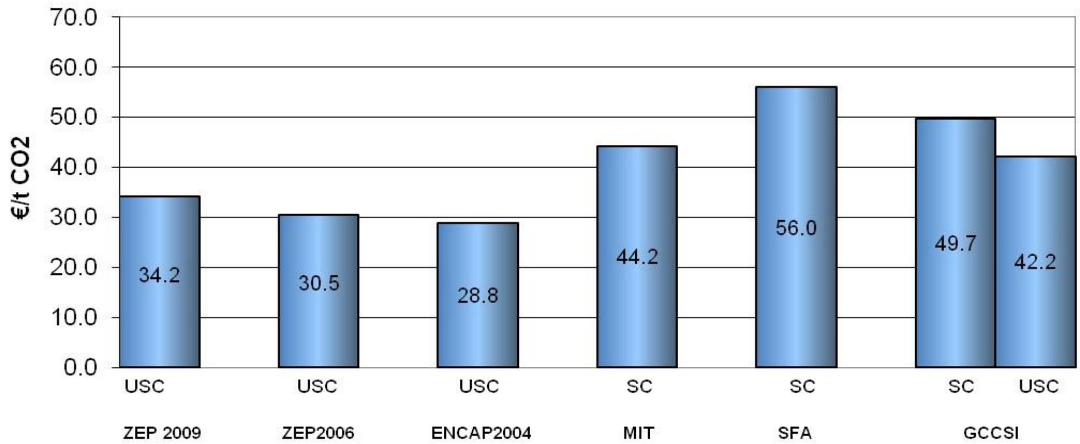


Figure 31: CO_2 avoidance costs for hard coal-fired power plants with oxy-fuel capture

Even taking into consideration the uncertainties of this simplified comparison in calculating the CO_2 avoidance costs by referencing all the studies to the reference power plant of this study, the following conclusions can be made:

- As with other studies, the CO_2 avoidance costs are higher for less efficient power plants based on the supercritical steam cycle.
- ZEP's levelised CAPEX of €28.1/MWh is in good agreement with GCCSI's figure of €29.7/MWh, although its levelised OPEX figures are some 15% lower than those assumed by GCCSI and its plant efficiency is 2% points higher, resulting in differing CO_2 avoidance costs.
- As with the other capture technologies, the costs determined in this study are considerably higher than those of European studies using 2004 and 2006 data, and represent a more realistic approach to the determination of plant costs.

In 2008, McKinsey published the following costs for an early commercial power plant:

McKinsey Published results 2008		Min	Max
CAPEX	€/t CO2	14	19
O&M cost	€/t CO2	5	7
Fuel cost	€/t CO2	2	6
CO2 avoidance cost	€/t CO2	25	32

The CO_2 avoidance costs calculated in this study are:

ZEP Study, 2009 data		Min	Max
BASE			
Levelised CAPEX	€/t CO2	28.8	39.4
Levelised OPEX	€/t CO2	3.4	8.9
Levelised Fuel	€/t CO2	9.8	10.0
CO2 avoidance cost	€/t CO2	42.1	58.2
OPTI			
Levelised CAPEX	€/t CO2	16.3	22.2
Levelised OPEX	€/t CO2	6.2	7.8
Levelised Fuel	€/t CO2	8.1	10.0
CO2 avoidance cost	€/t CO2	30.5	39.9

The McKinsey study predicts a slightly lower cost than the OPTI power plant calculated in this study. This difference may be due to the higher plant efficiency and steam conditions assumed by McKinsey (40% plant efficiency, 700ºC steam cycle), resulting in a power plant with an efficiency of four points higher than that employed in this study. This difference will impact on both the fuel and maintenance costs. Power plant costs in this study are also calculated using data from commercially available cryogenic air separation plants. It is claimed by the manufacturers that there exists the possibility of obtaining a few percentage points improvement by reducing power consumption by around 40 kWh/tonne. It is not known whether such considerations were taken into consideration in the McKinsey study.

4.2 Lignite

4.2.1 Lignite PF coal-fired power plant with post-combustion capture

The only other studies of reference concerning lignite PF power plants with post-combustion were previously undertaken in Europe by ZEP and the Castor project, using 2006 data. The published costs are shown in the following table:

	ZEP 2009	ZEP 2006	Castor	McKinsey
	LIGNITE			
Levelised electricity cost (€/MWh)	75.2	48.0	59.1	
CO2 avoidance cost (€/t CO2)	38.9	20.4	33.7	25-32

Applying the methodology and boundary conditions used in this study, Figures 32 and 33 were produced showing the adjusted LCOE and CO_2 avoidance costs:

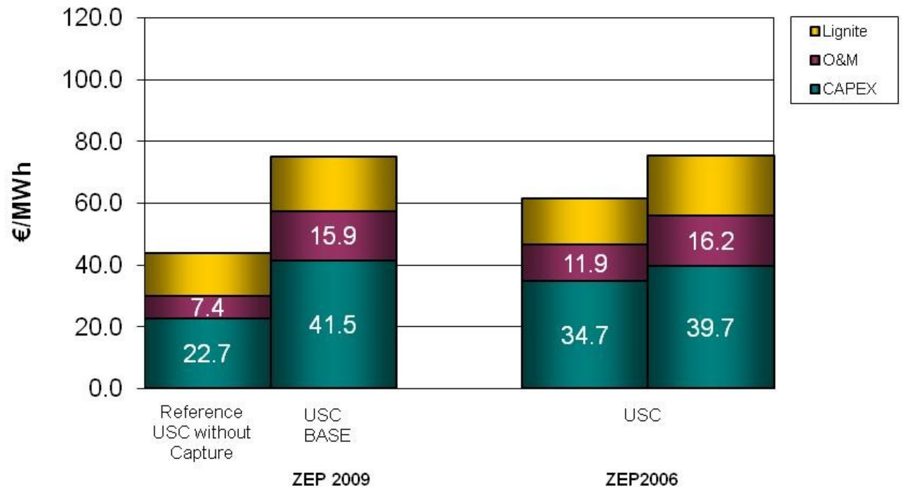


Figure 32: LCOE for lignite-fired power plants with post-combustion capture

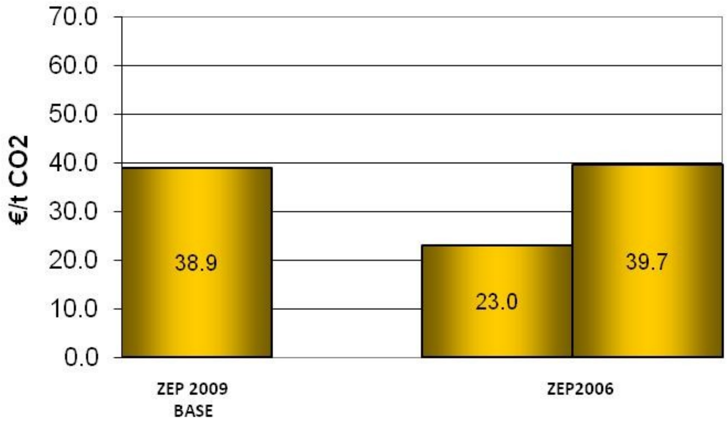


Figure 33: CO_2 avoidance costs for lignite-fired power plants with post-combustion capture

The only previous studies of lignite-fired PF power plants with post-combustion capture are European-based. The actual costs obtained are very similar to those of the Castor study, which are some 20% higher than the 2006 data used in the underlying report to ZEP's Strategic Research Agenda, "The final report from Working Group 1 – Power Plant and Carbon Dioxide Capture".

4.2.2 Lignite IGCC with pre-combustion capture

There have also been very few studies carried out for lignite-fired IGCC power plants – mainly European. The published costs are shown in the following table:

	ZEP 2009	ZEP 2006	ENCAP	McKinsey
	LIGNITE			
Levelised electricity cost (€/MWh)	67.4	43.9	41.4	
CO2 avoidance cost (€/t CO2)	29.9	15.0	17.7	25-32

Applying the methodology used in this study, it can be observed that the costs obtained in this study are higher than those of previous European studies and probably represent a more realistic view of the costs of this technology (Figures 34 and 35):

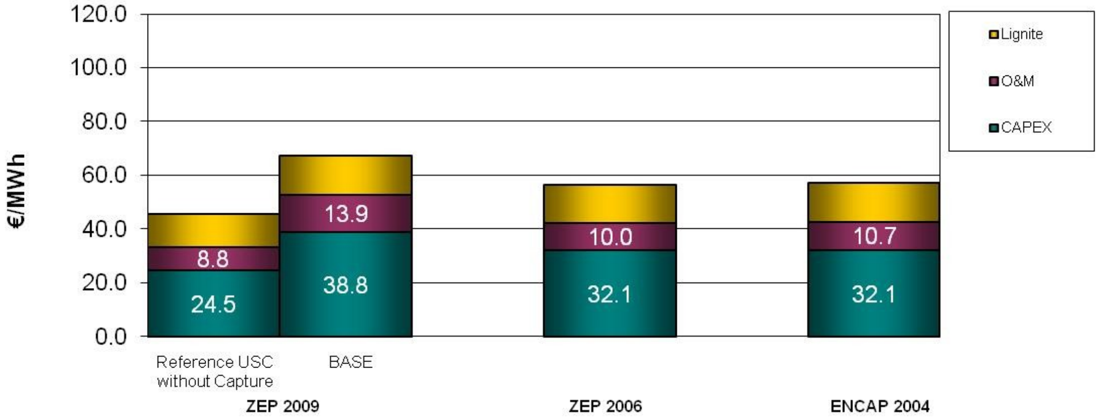


Figure 34: LCOE for lignite-fired IGCC power plants with pre-combustion capture

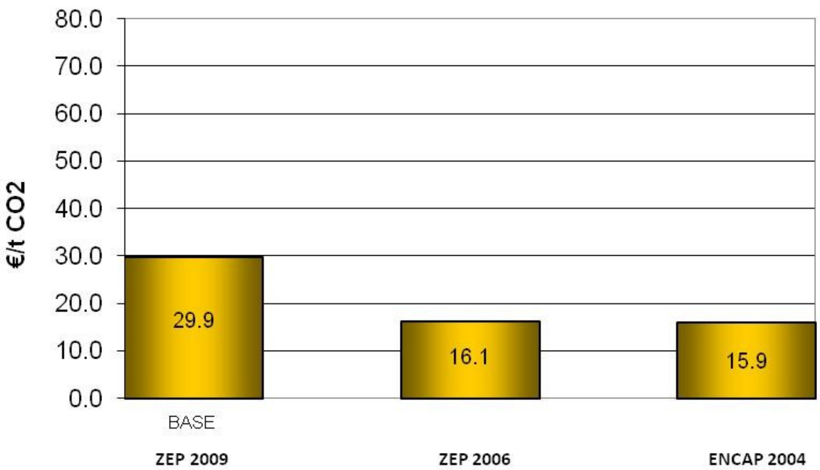


Figure 35: CO_2 avoidance costs for lignite-fired IGCC power plants with pre-combustion capture

4.2.3 Lignite oxy-fuel PF power plant

The only previous studies carried out on lignite-fired oxy-fuel power plants have been European. When adjusted to the boundary conditions of this study, the LCOE and CO_2 avoidance costs for these studies are shown in Figures 36 and 37:

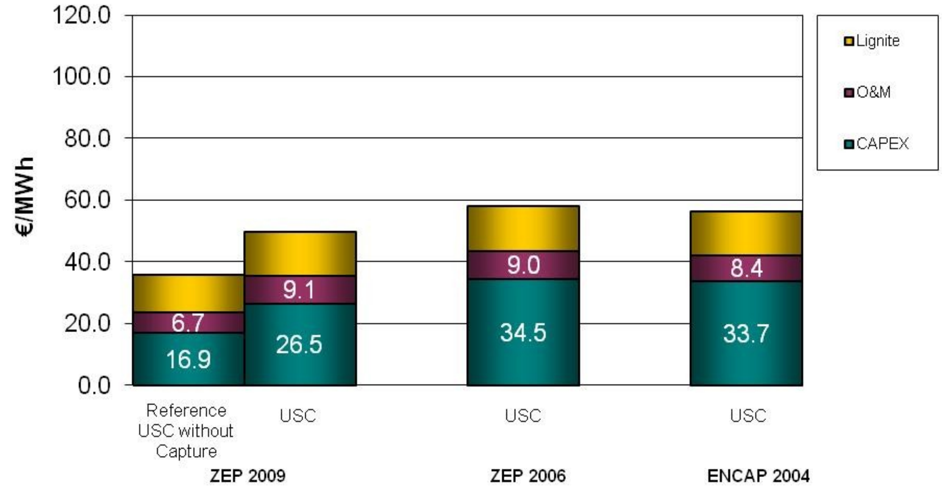


Figure 36: LCOE for lignite-fired OPTI power plants with oxy-fuel capture

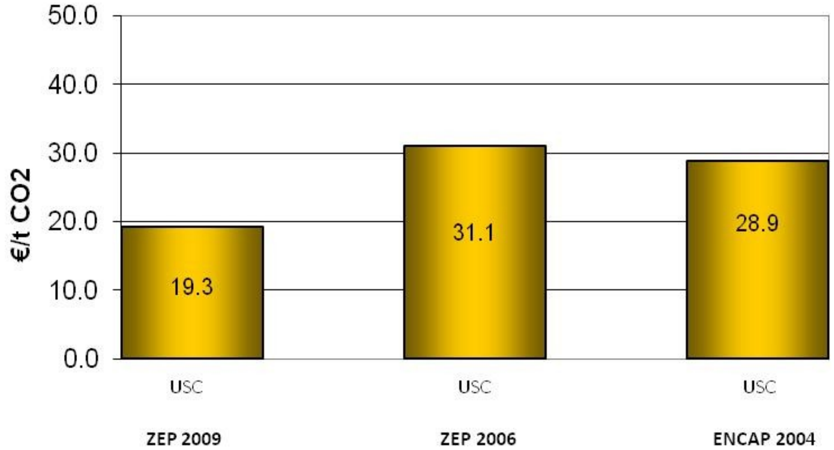


Figure 37: CO_2 avoidance costs for lignite-fired OPTI power plants with oxy-fuel capture

The costs determined in this study are considerably lower than those published in previous studies for an OPTI early commercial power plant. However, as previously mentioned, the costs for this option are considered to be very ambitious and could be on the low side. It should be noted that this is in marked contrast to the results for the lignite-fired PF power plant with post-combustion capture and lignite-fired IGCC with pre-combustion capture, where the costs developed in this study are considerably higher than those determined in previous European studies.

4.3 Natural gas

4.3.1 Natural gas combined cycle with post-combustion capture

The following table shows the results of the various studies:

	ZEP 2009 BASE	ZEP 2009 OPTI	ZEP 2006	NETL/DOE	EPRI	Rubin	SFA	Global CCSI	Mott McDonald (FOAK)
	NATURAL GAS								
Levelised electricity cost (€/MWh)	103.5	91.5	68.8	65.3	52.7	54.0	55.7	83.6	123.75
CO_2 avoidance cost (€/t CO_2)	109.7	79.0	64.7	55.6		41.9	48.9	83.9	

N.B. Data from the GGCSI and Mott McDonald are for combined capture, transport and storage costs, not just capture.

Applying the methodology and boundary conditions used in this study and assuming all the plants in the other studies are more representative of an OPTI plant (except where stated), Figures 38 and 39 have been produced for the LCOE and CO_2 avoidance costs:

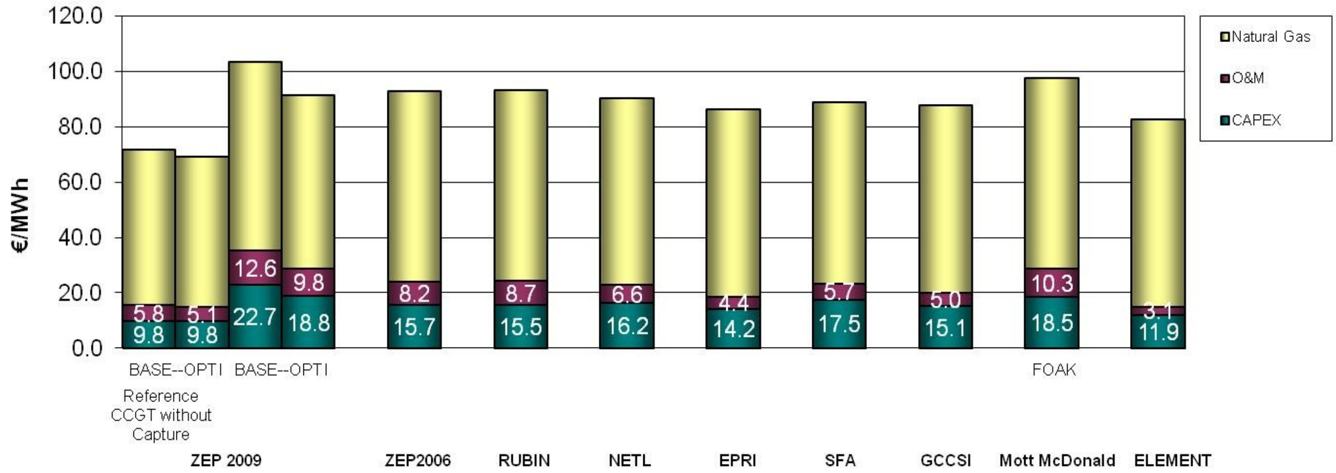


Figure 38: LCOE for CCGT power plants with post-combustion capture

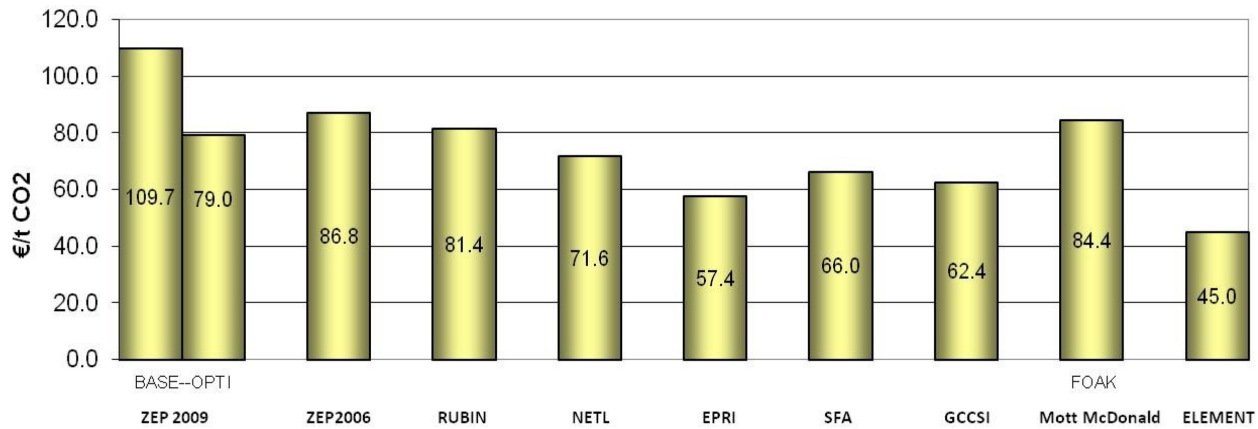


Figure 39: CO_2 avoidance costs for CCGT power plants with post-combustion capture

The costs obtained for the OPTI power plant in this study are comparable with the DECC study, but somewhat higher than those from the GCCSI, SFA, EPRI NETL and Rubin. Both the capital costs and O&M costs determined in this study are higher, suggesting that it has adopted a more conservative approach.

5 Future Trends in CO_2 Capture Costs and Impact of Second-Generation Technologies

5.1 Post-combustion capture

The first-generation post-combustion capture systems analysed in this study are based on liquid chemical solvents, commonly an amine-based reagent that imposes a large energy penalty in the capture process. ZEP's 2010 publication, "Recommendations for research to support the deployment of CCS in Europe beyond 2020" identified the following potential improvements for solvents:

Summary table: Post combustion CO_2 capture
(Colour codes: Green – validated, Yellow – partly validated, Red – not validated)

	-2020	2020-2030	2030-
Liquid solvents, energy requirement < 3 GJ/ton CO_2	Green	Green	Green
Liquid solvents, energy requirement < 2 GJ/ton CO_2	Yellow	Green	Green
Liquid solvents, energy requirement < 1.5 GJ/ton CO_2	Red	Red / Yellow	Green
Minimisation of solvent degradation / avoidance of emissions	Yellow	Yellow	Green
VSA / VPSA adsorbents	Red / Yellow	Yellow	Green
Low temperature thermal swing adsorbents	Red / Yellow	Yellow	Green
High temperature thermal swing adsorbents	Red / Yellow	Yellow	Green
Capture processes for liquid and solid sorbents*	--	--	--
Membranes development (higher flux and selectivity) and stability	Yellow	Yellow / Green	Green
Cryogenics: anti-sublimation	Yellow	Green	Green
Hydrates	Red	Yellow	Green

*Maturity will depend on the solvent or sorbent under consideration

Progress in this area will lead to an improvement in plant efficiency as the energy requirements of the capture plant should diminish. Assuming that an improvement in plant efficiency can be obtained without incurring additional plant cost, the following cost reductions could be expected:

	Plant Efficiency %	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal PF Post-Combustion Capture Studied	38	70.3	33.3
Plant Efficiency Improvement of 1 point	39	69.7	32.2
Plant Efficiency Improvement of 2 points	40	69	31.1
Plant Efficiency Improvement of 3 points	41	68.4	30.1
Plant Efficiency Improvement of 4 points	42	67.8	29.1

Other improvements identified for post-combustion capture processes are power plant efficiency improvements due to a higher temperature/pressure steam cycle. Research development is ongoing for the 700ºC, 350 bar steam cycle that will result in plant efficiency improvements and therefore a reduction in CO_2 avoidance costs. However, it is difficult to assess the impact of this technology as there are no reliable cost data available for such power plant designs.

Improvements in the integration of the capture plant and compression islands should also result in efficiency improvements, as will the commercialisation of the capture power plants. The potential impact of reducing the capital costs is shown in the following table:

	Plant Cost €/kWh	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal PF Post-Combustion Capture Studied	2,450	70.3	33.3
Plant Cost reduction of 5%	2,327.5	68.8	31.1
Plant Cost reduction of 10%	2,205.0	67.3	28.8
Plant Cost reduction of 15%	2,082.5	65.8	26.6

The sensitivities shown for the cost reduction and efficiency improvements imply that both are required to obtain a substantial savings in CO_2 avoidance costs for post-combustion capture systems.

In the case of natural gas combined cycle power plants with post-combustion capture, the CO_2 content in the flue gas is very diluted, being in the range of 3%-5%, and therefore technology improvements to increase the CO_2 concentration in the flue gas are important – in particular, flue gas recirculation. However, no cost data are available to evaluate accurately the impact of this improvement.

5.2 IGCC with pre-combustion capture

The IGCC with pre-combustion CO_2 capture is considered to be the most developed of the first-generation technologies, as the majority of components have already been demonstrated at full scale in separate applications and the issue is to integrate them into a reliable power plant concept.

In this study, the IGCC power plants employ cryogenic air separation for both oxygen and nitrogen supply as this is the only viable air separation technology currently available. In the first instance, it is believed that there exists the possibility of reducing energy consumption for oxygen production from 250 to 310 kWh/tonne (oxygen at 4 MPa at ISO conditions) with nitrogen integration by around 40 kWh/tonne, based on improved cryogenic processes. It is also foreseen that in the longer term, further development of adsorbents and membranes will lead to a more energy- and cost-efficient technology for oxygen production.

Summary table: Oxygen production for pre-combustion applications.

(Colour codes: Green – validated, Yellow – partly validated, Red – not validated)

	-2020	2020-2030	2030-
Advanced cryogenic distillation, integration with other parts of the power plant			
Oxygen separating membranes (flux, selectivity, stability, manufacturing)			
OTM integration in power plant			
Adsorbent based O_2 production (O_2 capacity, stability, manufacturing)			
Adsorbent based O_2 production integration in process			
Demonstration plants			

The development of larger gasifiers with efficient heat recovery, simplified gas cleaning processes, improved water gas-shift catalysts and new gas turbines that can operate on hydrogen-rich fuel gas with new dry low NOx (DLN) combustion should lead to both cost savings and efficiency improvements for this technology.

The sensitivity of efficiency improvement and cost savings are shown in the following two tables:

	Plant Efficiency %	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal IGCC with pre-combustion capture	38	74.7	39.8
Plant Efficiency Improvement of 1 point	39	74	38.6
Plant Efficiency Improvement of 2 points	40	73.3	37.5
Plant Efficiency Improvement of 3 points	41	72.7	36.5
Plant Efficiency Improvement of 4 points	42	72.1	35.5

	Plant Cost €/kWh	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal IGCC with pre-combustion capture	2,800	74.7	39.8
Plant Cost reduction of 5%	2,660	72.4	36.4
Plant Cost reduction of 10%	2,520	70.1	32.9
Plant Cost reduction of 15%	2,380	67.8	29.5

5.3 Oxy-fuel PF power plants

As with IGCC pre-combustion capture, the first-generation oxy-fuel power plants employ a cryogenic air separation plant for the oxygen and nitrogen supply. As stated previously, it is foreseen that future developments and optimisation will reduce the energy consumption for oxygen production from 160 to 220 kWh/tonne (ISO conditions) to a figure approaching 120-140 kWh/tonne. New membrane or sorbent technologies may further reduce this figure down to 90-120 kWh/tonne, resulting in an overall plant efficiency improvement.

Summary table: Oxygen production for oxyfuel applications.
(Colour codes: Green – validated, Yellow – partly validated, Red – not validated)

	-2020	2020-2030	2030-
Advanced cryogenic distillation			
Oxygen separating membranes (flux, selectivity, stability, fabrication)			
Oxygen separating adsorbents (O_2 capacity, stability)			
Membrane and adsorbent material stability at sour conditions			
Membrane unit manufacturing, development and process integration			
Adsorbent unit development and process integration			
Membrane unit full scale demonstration plant			

There is extensive ongoing R&D work to validate the boiler design; combustion process; flue gas recycling and O_2 mixing; flue gas treatment and cooling; and CO_2 purification and compression that may lead to efficiency improvements and cost reductions.

The sensitivity of efficiency improvements and cost savings are shown in the following two tables:

	Plant Efficiency %	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal Oxy-fuel PF OPTI power plant	36.3	65.9	34.8
Plant Efficiency Improvement of 1 point	37	65.3	34
Plant Efficiency Improvement of 2 points	38	64.6	32.7
Plant Efficiency Improvement of 3 points	39	63.9	31.6
Plant Efficiency Improvement of 4 points	40	63.3	30.5

	Plant Cost €/kWh	Average Levelised Electricity Costs €/MWh	Average CO_2 Avoidance Cost €/t CO_2
Hard Coal Oxy-fuel PF OPTI power plant	2,200	65.9	34.8
Plant Cost reduction of 5%	2,090	64.4	32.7
Plant Cost reduction of 10%	1,980	63.0	30.6
Plant Cost reduction of 15%	1,870	61.6	28.5

5.4 Second-generation capture technologies

There is extensive ongoing R&D work to develop second-generation technologies that should lead to a step reduction in the cost of CO_2 capture. These concepts are still very much in the early stages of research and development, being currently demonstrated in pilot plants often below 1 MWt in size. For this reason, very little reliable cost data exist for an industrial-scale power plant of these technologies. Indeed, this study has not unearthed any new cost data since those published by ENCAP in 2006 (see page 54). As a result, in the following sub-sections, the ENCAP data has been adjusted to second quarter 2009 capital costs and the costs calculated using the boundary conditions established in this study.

5.4.1 Hard coal-based technologies

Chemical looping combustion (CLC) is a second-generation oxy-fuel technology where the separation of oxygen from air is integrated in the combustion process. Metal particles are oxidised in an air reactor, the resulting metal oxide particles are transported to a fuel reactor, where they are reduced as fuel is oxidised and fuel heat released. The metal particles are then transported back to the air reactor where they can be oxidised again. The ENCAP work studied the following concept:

- 445 MW CFB CLC: when applied for solid fuels, a CLC boiler is typically based on CFB technology consisting of two interconnected circulating CFB units producing steam in a conventional Rankine cycle.

The costs obtained for this concept, along with the costs for an OPTI oxy-fuel power plant calculated in this study, are shown in Figures 40 and 41:

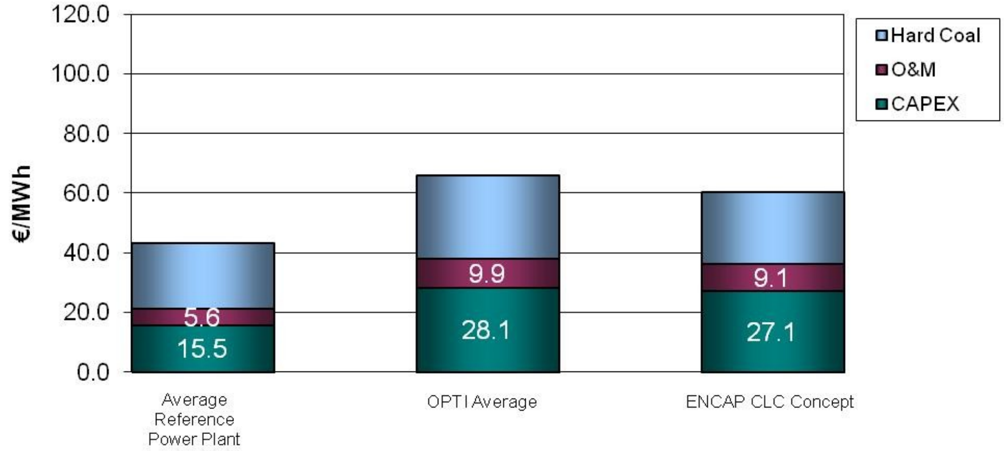


Figure 40: LCOE for hard coal-fired power plants with oxy-fuel capture – a comparison between ZEP and ENCAP CLC Concept

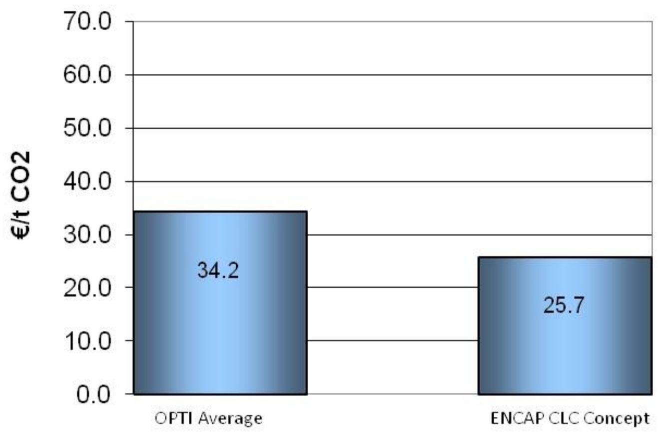


Figure 41: CO_2 avoidance costs for hard coal-fired power plants with oxy-fuel capture – a comparison between ZEP and SP4 CLC

The driving force for the Chemical Looping is the potential reduction in efficiency drop, which was identified by the ENCAP study as only 2% points efficiency drop compared to their reference case. The reduction in energy penalty is due to the fact that the vast majority of the oxygen separation plant is not required. In terms of capital cost, the reduction in the air separation unit is offset by the fact that the process requires two interconnected CFB reactors. The figures seem to suggest the merit in pursuing this technological option, even though a process based on two interconnected reactors could cause operational difficulties.

5.4.2 Natural gas-based technologies

CLC technology discussed for hard coal is also applicable to natural gas. The ENCAP project identified the following cycles based around CLC:

- 393 MW natural gas CLC (Chemical Looping Combustion) CC (Combined Cycle): one CLC reactor is installed before each air turbine stage. The air is used to generate steam for a bottoming cycle after the last air turbine stage; one CO_2 turbine, with CO_2 added at different pressure levels. The following two variants are considered:
  - CLC CC double reheat air turbine, rotating reactors: three air turbine stages, rotating CLC reactor
  - CLC CC double reheat air turbine, membrane assisted reactors: three air turbine stages, membrane assisted CLC reactors.
- CLC CC single reheat air turbine: two air turbine stages are considered.

In addition to the CLC, the following oxy-fuel cycles were identified as possible future options:

- 393 MW natural gas water cycle: a reheat oxy-fuel cycle where liquid water is re-circulated to the first combustion chamber for temperature control, e.g. the Clean Energy Systems cycle.
- 393 MW natural gas cycle: Original Graz Cycle, an oxy-fuel cycle where CO_2 and a small quantity of steam is re-circulated to the combustion chamber for temperature control.
- 393 MW natural gas SP6 S-Graz Cycle: an oxy-fuel cycle where both steam and CO_2 are re-circulated to the combustion chamber for temperature control. More steam is re-circulated than in the original Graz cycle.
- 393 MW natural gas SP6 SCOC-CC: a semi-closed oxy-fuel combined cycle where most of the CO_2-rich gas from the condenser is re-circulated to the gas turbine compressor; HRSG with two pressure levels and one reheat.

The preliminary projected costs for these technologies, taken from the ENCAP studies and adjusted to the boundary conditions of this study, are shown in Figures 42 and 43:

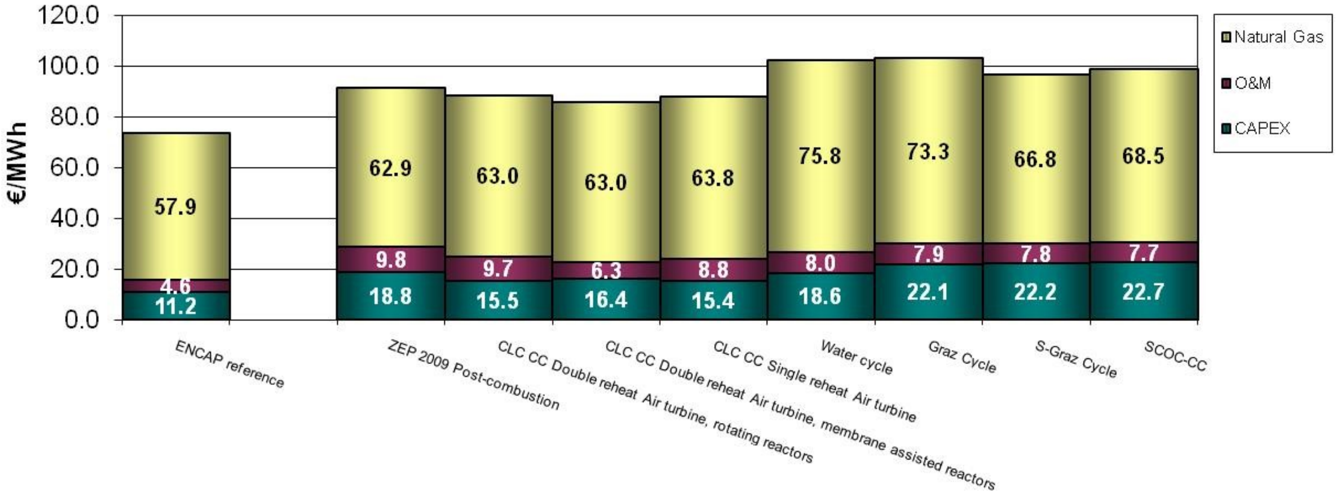


Figure 42: LCOE for natural gas-fired power plants with oxy-fuel capture

The LCOE for the OPTI CCGT with post-combustion capture is included in the above graph and a middle fuel price of €8/GJ has been used in the calculations. It can be observed that the CLC concepts offer a fractional reduction in LCOE costs. However, when comparing the CO_2 avoidance costs, the following results have been determined:

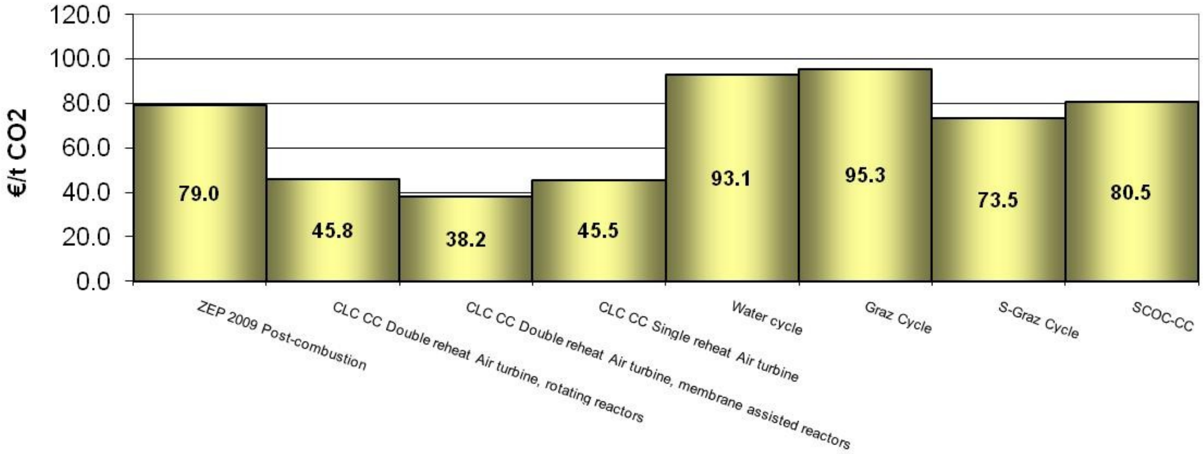


Figure 43: CO_2 avoidance costs for natural gas-fired power plants with oxy-fuel capture

The CO_2 avoidance cost for the OPTI CCGT post-combustion capture is considerably higher than the CLC concepts. In this case, it must be noted that the reference power plants are not the same: the ENCAP concepts are referenced against their reference plant, whilst the CCGT post-combustion capture is referenced against the ZEP power plant reference.

All the capture technologies reduce net efficiency when compared to the reference case. For differentiation, the S-Graz cycle efficiency is decreased by 8% and the SCOC-GT efficiency is decreased by 9%, whereas the decrease is ~12% for the Graz and ~13% for the water cycle, compared to the base case of 56.5%.

The CLC combined cycles potentially have the highest cycle efficiencies (51%-52%), but this design includes pressurised CLC reactors, which is very advanced technology. The CLC reactors also limit possible increases in turbine inlet temperature and thereby possibilities to benefit from future developments towards higher efficiency of the gas turbine cycle. It is therefore uncertain if a CLC natural gas-based system would still have a competitive advantage when compared to a future natural gas post-combustion option with a more efficient gas turbine.

In general, the novel oxy-fuel cycles are immature, even when compared to the CLC cycles; will be more expensive in investment costs; and construction time will be increased due to the higher degree of integration and complexity of these plants.

When comparing specific investments for these new technologies, those for these novel concepts increase compared with reference cases due to more expensive equipment, air separation processes and the CO_2 compression in the oxy-fuel cycles and more expensive equipment in the CLC CC concepts.

The ENCAP project also identified the following pre-combustion gas concepts:

- ATR pre-combustion ASU: IRCC (Integrated Reforming Combined Cycle) with cryogenic ASU for oxygen production to the ATR (Autothermal Reformer) and MDEA (MethylDiEthanolAmine) for pre-combustion CO_2 capture; not much integration with respect to heat and air compression, giving a relatively low energy efficiency, but higher flexibility. Two parallel F-class gas turbines in a CC of the same type as in the ENCAP reference NGCC. In the ENCAP project, development work was performed, aiming at the adaptation of burners for hydrogen-rich gases to the design requirements of modern high temperature F-class gas turbines. This is the most near-term of the pre-combustion gas concepts.

- Pre-combustion CAR: the concept is a hybrid between pre-combustion and oxy-fuel. CAR (Ceramic Autothermal Recovery) is a BOC/Linde technology for separating air with a high temperature Pressure Swing Adsorption (PSA). The process consists of a CAR unit, oxy-fuel steam reformer (tubular reactor) and a conventional PSA unit for separating the synthesis gas into H_2 from a fuel stream (CH_4, CO, CO_2). The H_2 is combusted in a similar combined cycle as in the ATR Pre-combustion ASU concept. The fuel stream is combusted in the steam reformer with O_2 from the CAR unit for providing heat to the synthesis gas production in the tubes. A part of the steam reformer combustion product (mainly CO_2) is used for sweeping the CAR unit and recycled to the steam reformer. The rest is compressed for geological storage. This is a novel and immature concept developed in ENCAP. Two parallel F-class gas turbines in a CC of the same type as in the ENCAP reference NGCC. In the ENCAP project, development work was performed, aiming at adaptation of burners for hydrogen-rich gases to the design requirements of modern high temperature F-class gas turbines.
- Pre-combustion membrane: pre-combustion cycle with an ATR membrane reactor with an oxygen permeable membrane (ceramic) with a higher total pressure on the permeate side of the membrane than on the retentive side; water-gas-shift membrane reactor with a hydrogen-permeable membrane.
- Pre-combustion membrane, high pressure pre-combustion cycle with an ATR membrane reactor with an oxygen permeable membrane (ceramic) with a higher total pressure on the permeate side of the membrane than on the retentive side. Water-gas-shift membrane reactor with a hydrogen-permeable membrane. Compared to the 393 MW natural gas SP6 pre-combustion membrane, this cycle has a higher pressure on the permeate side of the membrane.

The preliminary projected costs for these technologies, that are simply an actualisation of the original ENCAP costs, are shown in Figures 44 and 45:

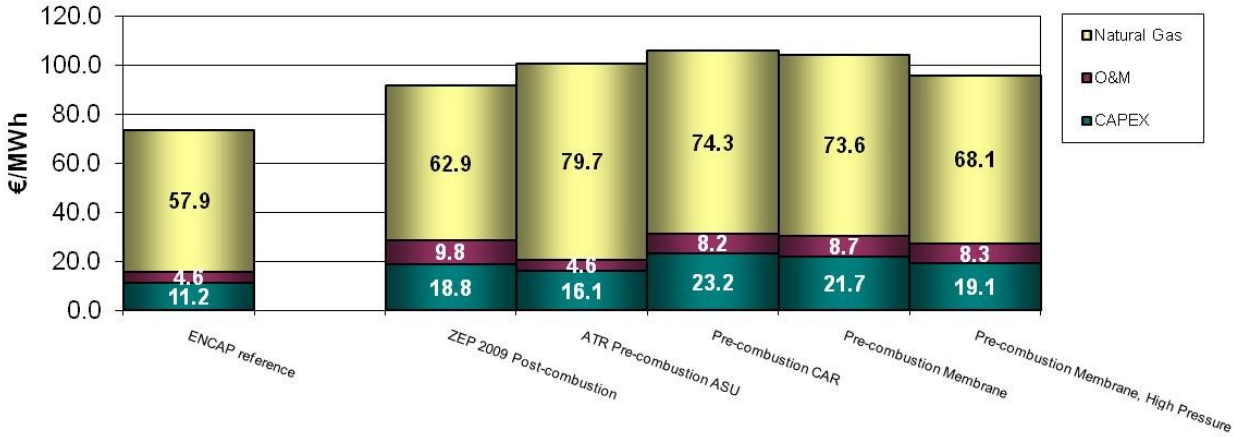


Figure 44: LCOE for natural gas-fired power plants with pre-combustion capture

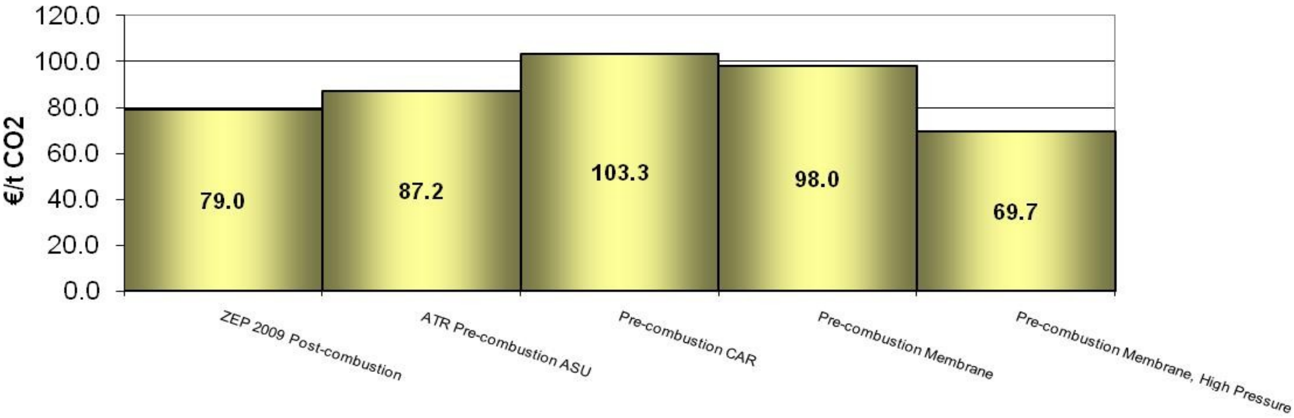


Figure 45: CO_2 avoidance costs for natural gas-fired power plants with pre-combustion capture

In all cases, it is inferred that the predicted costs for the novel cases do not imply a step-wise reduction in costs over the OPTI power plant option. However, future development work may identify cost reductions.

When comparing these novel cycles to the reference case, the major additional energy demands are due to the air separation processes: the natural gas combustion to heat the CAR absorber for the pre-combustion CAR concept, the reforming in the ATR and ST cycles respectively of natural gas to produce a hydrogen-rich gas, the CO_2 separation and the CO_2 compression. All these capture technologies reduce net efficiency compared to the reference case. The efficiency of the pre-combustion CAR concept (44%) is significantly higher than that of the ATR pre-combustion ASU concept (41%) due to the use of new but immature air separation technology, a PSA instead of an amine unit for CO_2 separation and a higher level of integration. The ATR pre-combustion ASU concept is based on conservative assumptions, i.e. its efficiency can be improved by more integration and less conservative assumptions.

The pre-combustion membrane, high pressure cycle has the highest efficiency with 48%, but is also the most immature. The efficiency of the pre-combustion membrane cycle (44%) is lower due to the use of lower pressure on the permeate side that may be more mature. However, both pre-combustion membrane concepts still seem less mature than the pre-combustion CAR concept due to the use of high temperature membranes. It seems that developing the CAR technology can take less time than the high temperature membranes.

Comparing specific investments, the main increases in equipment costs are due to:

- Pre-combustion concepts: the air separation processes – cryogenic ASU for the “first-generation” concept, the CAR absorber for the pre-combustion CAR concept and the membrane reactors for the pre-combustion membrane concepts – natural gas reforming, CO-shift, CO_2 separation and CO_2 compression.

The investment cost for the pre-combustion CAR and the pre-combustion membrane concepts are based on several conservative assumptions, considering assumptions on immature technologies. When comparing fixed O&M costs, the calculated costs for the ATR pre-combustion ASU concept are at a low level compared to the reference case.

The maturity and level of integration varies from case to case. Since the ATR pre-combustion ASU concept is based on conservative assumptions, it has a relatively low level of integration, but a high level of maturity.

It needs the development of a low NOx H_2 turbine which is common for all pre-combustion cases. The pre-combustion CAR concept seems to have a medium level of maturity, but a high level of integration. The pre-combustion membrane concepts have the lowest maturity due to the membrane modules; more than 10 years are claimed to be needed for their development. These differences have a clear effect on the energy efficiency – the most immature ones have the highest efficiency.

For the pre-combustion CAR concept, ENCAP reports the lifetime of the CAR adsorbent as an unknown; its economic success depends on it.

6 Acknowledgments

The work described this report has been possible solely due to the co-operation of participating ZEP members, resulting in a truly cross-border, cross-organisation product. Without their commitment, the challenging and constructive debate could not have been created, nor yielded such substantial results.

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Glossary

ASU	Air Separation Unit
BASE	Base power plant with CO_2 capture
CAPEX	Capital expenditure or investment
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CC	Combined cycle
CFB	Circulating Fluidised Bed
CH_4	Methane
CLC	Chemical Looping Combustion
CO	Carbon monoxide
CO_2	Carbon dioxide
DLN	Dry Low NOx
DOGF	Depleted oil and gas fields
EPC	Engineering Procurement and Construction costs
EU	European Union
EUR	Euro
FEED	Front End Engineering Design study
FGD	Flue gas desulfurisation
FOAK	First-of-a-kind
GCCSI	Global CCS Institute
GJ	Gigajoule
H_2	Hydrogen
H_2S	Hydrogen sulfide
HRSG	Heat Recovery Steam Generator
ID	Induced Draft
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure (IP)
kWh	Kilowatt Hour
LCOE	Levelised Cost of Electricity
LHV	Lower Heating Value
LP	Low Pressure
MMBtu	Millions of British thermal units
MWe	Megawatt Electricity
MWh	Megawatt Hour
MPa	Megapascal
MWt	Megawatt tonne
NGCC	Natural Gas Combined Cycle
NGO	Non-governmental organisation
NOx	Nitrogen Oxide
O&M	Operation and Maintenance
OPEX	Annual operational expenditure
OPTI	Optimised power plant with CO_2 capture
PF	Pulverised Fuel
PSA	Pressure Swing Adsorption
R&D	Research and Development
SOx	Sulphur Oxide
ST	Steam Turbine
t CO_2	Tonne of CO_2
USC	Ultra Super Critical
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants, known as the Zero Emissions Platform

Annex: List of Figures

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