ECONOMIC ASSESSMENT OF CARBON CAPTURE AND STORAGE TECHNOLOGIES

2011 update

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PREFACE

This report presents an update of the economics of Carbon Capture and Storage (CCS) prepared in 2009. The 2009 report was commissioned by the Global CCS Institute and delivered as Foundation Report Two in the series of five studies undertaken as part of the Strategic Analysis of the Global Status of Carbon Capture and Storage.

Foundation Report Two involved a detailed analysis of the capture, transport and storage costs for power plants and a select range of industrial applications. This report presents a transparent methodology that uses updated and refined costs to reflect changes in the market since 2009.

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ECONOMIC ASSESSMENT OF CARBON CAPTURE
AND STORAGE TECHNOLOGIES: 2011 UPDATE

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ABBREVIATIONS

3D	3-Dimensional
AACE	Association for the Advancement of Cost Engineering
AD, A$	Australian dollar
AFUDC	Allowance for Funds Used During Construction
AGR	acid gas removal
ANZ	Australia and New Zealand
ASU	air separation unit
CAPEX	capital expense
CCS	carbon (carbon dioxide) capture, transport and storage
CO_2	carbon dioxide
CO_2CRC	the Australian Government's Cooperative Research Centre for Greenhouse Gas Technologies
CTG	combustion turbine generator
ºC	degrees Celsius
DrillEX	drilling expenditure
ECBM, ECBMR	enhanced coal bed methane recovery
EGR	enhanced gas recovery
EIA	(United States) Energy Information Administration
EOR	enhanced oil recovery
EPC	engineering, procurement and construction contract or contractor
EPCM	engineering, procurement, construction and management contract or contractor
EPRI	Electric Power Research Institute
FEED	front-end engineering design
FGD	flue gas desulphurisation
FGR	flue gas recirculation
FID	final investment decision
FOAK	first-of-a-kind
FOM	fixed operating and maintenance
FRST	Foundation for Research Science and Technology
G8	Group of Eight (Canada, France, Germany, Italy, Japan, Russia, the United Kingdom, and the United States)
GHG	greenhouse gas
GNS	GNS Science, a New Zealand research and consultancy services organisation
GJ	gigajoules
GWe	gigawatt-electrical
HHV	higher heating value
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
ITM	ion transfer membrane
kg	kilogram
kJ	kilojoule
km	kilometre
kW, kWe	kilowatt-electrical
LCOE	levelised busbar cost of electricity, often expressed in $/MWh
LNB	low NOx burner
m	metre
ME	Middle East
MEA	monoethanolamine
MMV	measurement, monitoring and verification
MPa	megapascal
Mtonne, Mt	million (106) tonnes
Mtpa	million (106) tonnes per annum
MW, MWe	megawatt-electrical
MWh	megawatt-hours
NA, N/A	not applicable
NETL	US DOE National Energy Technology Laboratory
NGCC	natural gas-fired combined cycle
NOAK	nth-of-a-kind
NOx	nitrous oxides
O&M	Operating and Maintenance
OFO	overfire oxygen
OPEX	operating and maintenance expense
pa	per annum
Pa	pascal = N/m^2
PC	pulverised coal
PCC	post-combustion capture
PPP	Public Private Partnership
RD&D	research, development and demonstration
R&D	research and development
ROW	right(s) of way
SCR	selective catalytic reduction
Sm^3	standard cubic metres
Svy	survey
Syngas	synthetic gas
tonne	metric ton, (1,000kg)
TPC	total plant cost
UK	United Kingdom
USA, US	United States of America
USC	ultra-supercritical
USD, US$	United States dollar
US DOE	United States Department of Energy
US EIA	United States Energy Information Administration
US EPA	United States Environmental Protection Agency
USGC	US Gulf Coast
VOM	variable operating and maintenance

1 EXECUTIVE SUMMARY

In May 2009, a consortium led by WorleyParsons and comprising Schlumberger, Electric Power Research Institute and Baker & McKenzie was engaged to undertake the Strategic Analysis of the Global Status of Carbon Capture and Storage (CCS).

The consortium was tasked with undertaking a comprehensive survey of the status of CCS and to develop a series of reports analysing CCS projects, the economics of CCS, policies supporting CCS development and existing research and development networks. A fifth report – the Synthesis Report – was also developed and this summarised the findings of the first four reports, and provided a comprehensive assessment of the gaps and barriers to the deployment of large-scale CCS projects, including strategies and recommendations to address these issues.

The second of this series of reports (Foundation Report Two) presented a detailed analysis of the capture, transport and storage costs for power plants and a select range of industrial applications. The costs of CCS were presented on a levelised cost of production basis, as well as for the cost of carbon dioxide (CO_2) captured and avoided. Foundation Report Two also considered the application of CCS in first-of-a-kind (FOAK) systems and n^{th}-of-a-kind (NOAK) systems.

The modelling determined that the cost of CCS for power generation, based on the use of commercially available technology, was found to range from US$57-107 per tonne of CO_2 avoided or US$42-90 per tonne of CO_2 captured. The lowest cost of CO_2 avoided was at US$57 per tonne of CO_2 for the oxyfuel combustion technology, while the highest cost at US$107 per tonne of CO_2 for the natural gas-fired combined cycle (NGCC) with post-combustion capture (PCC). This compared with the lowest cost of captured CO_2 for the IGCC and oxy-combustion technologies at US$39 and US$42 per tonne of CO_2 respectively and the highest of $90 per tonne of CO_2 for NGCC technologies. The metrics were determined for the reference site in the United States of America (USA) with fuel costs based on values typical for 2010.

For the reference cases, taking into account currently available technologies, the levelised cost of electricity (LCOE) for FOAK pulverised coal (PC) supercritical technology was the greatest at US$131/MWh, while the oxy-combustion was the lowest of the commercially available technologies at US$121/MWh. While the cost of CO_2 avoided and captured range by a factor of two, the LCOE estimates ranged between US$121-131/MWh with currently available technologies.

The percentage increases in costs that the application of CCS has over non-CCS facilities were also explored. For power generation, facilities that had the lowest cost increases were IGCC (37 per cent), NGCC (40 per cent), followed by oxyfuel combustion (53 to 65 per cent) and PC supercritical (61 to 76 per cent) technologies.

The application of CCS for FOAK industrial applications showed that cost of CO_2 avoided was lowest for natural gas processing (US$19) and fertiliser production (US$20) followed by cement production and blast furnace steel production (US$54).

1 EXECUTIVE SUMMARY (CONTINUED)

The lowest cost increase was for natural gas processing (1 per cent) followed by fertiliser production (3 per cent). This was unsurprising given that these industries already have the process of capturing CO_2 as a part of their design. The production of steel (10 to 14 per cent) and cement (39 to 52 per cent) had the highest percentage cost increases with the application of CCS because the capture of CO_2 is not inherent in the design of these facilities.

The margin of error in this study made it difficult to select one technology over another based on the LCOE. Projects employing different capture technologies may be viable depending on a range of factors such as location, available fuels, regulations, risk appetite of owners and funding.

In July 2010, WorleyParsons and Schlumberger were engaged to undertake an update of Foundation Report Two. The objectives of this update were to:

- improve the regional localisation estimates;
- update and enhance capital cost estimates for power and a select range of industrial activities that could apply CCS; and
- update the economic model (having regard for the two previous items) to consider what, if any, material changed have occurred to the economics of CCS since 2009.

To meet these objectives, changes/modifications to the economic assessment methodology included:

- the revision of overnight capital costs used in the 2009 report to early 2010 US$;
- the revision of regional specific factors to move the capital costs from the reference location to the location of interest;
- the review of coal and natural gas prices on a regional basis, including the consideration of whether the fuels were locally sourced or imported and subject to international market prices;
- the adjustment of process parameters (heat rate, CO_2 emissions and CO_2 capture) according to regional coal composition and emissions requirements;
- a change in the approach for CCS on the oxyfuel combustion power generation to include an additional purification step of the CO_2 to increase the CO_2 purity to greater than 95 per cent;
- the modification of the reference pipeline length to 100km, based on findings for large-scale integrated CCS projects as identified in Foundation Report One;
- a revised approach to CO_2 storage, which considered two cases of a ‘good’ reservoir and a ‘poorer’ reservoir with either 3Mtpa or 12Mtpa injection scenarios; and
- consideration of variations in storage costs across regions. Recent data on CO_2 storage costs were obtained for Australia/New Zealand, Europe and North America for CO_2 injection wells and associated services.

The revised results of the economic assessment of CCS technologies are presented in Table 1-1.

Table 1-1 Summary results of the economic assessment of CCS technologies

		Power generation				Industrial applications			
		PC supercritical & ultra supercritical*[1]	**Oxyfuel combustion standard & ITM*[1]**	**IGCC**	**NGCC**	**Blast furnace steel production**	**Cement production**	**Natural gas processing**	**Fertiliser production**
	Dimensions	**US$/MWh**	**US$/MWh**	**US$/MWh**	**US$/MWh**	**US$/tonne steel**	**US$/tonne cement**	**US$/GJ natural gas**	**US$/tonne ammonia**
Levelised cost of production	Without CCS*[2]	73-76	73-76*[3]	91	88	570-800	66-88	4.97	375
	With CCS FOAK*[3]	120-131	114-123	125	123	82	34	0.056	11
	With CCS NOAK*[4]	117-129	112-121	123	121	74	31	0.056	11
	% Increase over without CCS*[5]	61-76%	53-65%	37%	40%	10-14%	39-52%	1%	3%
Cost of CO_2 avoided*[6] (\$/tonne CO_2)	FOAK	62-81	47-59	67	107	54	54	19	20
	NOAK	57-78	44-57	63	103	49	49	19	20
Cost of CO_2 captured (\$/tonne CO_2)	FOAK	53-55	42-47	39	90	54	54	19	20
	NOAK	52	41-45	38	87	49	49	19	20

Notes:

1. The ultra-supercritical and ITM technologies are currently under development and are not commercially available. These technologies represent options with the potential for increasing the process efficiency and reducing costs.
2. Without CCS cost of production for industrial process are typical market prices for the commodities.
3. Oxyfuel combustion systems are not typically configured to operate in an air fired mode. Therefore, oxyfuel combustion without CCS is not an option. The values here are the PC without CCS value to be used as a reference for calculating the cost of CO_2 avoided.
4. For industrial processes, levelised cost of production presented as cost increment above current costs.
5. Expressed with respect to current commodity prices of industrial processes.

The updated modelling yielded the findings listed below.

- All of the coal-fired technologies showed a decrease in fuel costs related to the lower coal costs in 2010.
- For the reference cases, taking into account currently available technologies, the lowest LCOE was for oxyfuel combustion at US$114/MWh, in contrast to 2009 where LCOE for NGCC technologies was the lowest at US$112/MWh. Consistent with the findings in 2009, the LCOE for PC supercritical and IGCC technologies were the greatest at US$131/MWh and US$125/MWh respectively.
- The percentage increases in costs that the application of CCS has over non-CCS facilities have remained relatively unchanged since 2009.
- There was an increase in the capital contribution to the LCOE for oxyfuel combustion with CCS, reflecting the inclusion of an additional purification process when capturing CO_2.
- CO_2 capture still represents the greatest contribution to the cost of CCS, with the majority of the cost increases being due to changes in the capture system.
- The reduction in the length of the pipeline for the reference case has reduced the overall transport costs and the contribution of transport cost to the overall cost of CCS.

1 EXECUTIVE SUMMARY (CONTINUED)

- Consistent with the findings from Foundation Report Two in 2009, the range in coal price lead to a US$10/MWh variation in the LCOE, while for the natural gas price range the variation in the LCOE was around US$30/MWh.
- For a supercritical PC with CCS technology, for a fixed fuel cost, the sensitivity of the CO_2 capture installed capital costs and LCOE to the labour costs was reduced. The installed capital costs increased by 23 per cent (32 per cent in 2009), while the LCOE increased by 11 per cent (21 per cent in 2009). A similar trend would be observed for the other coal-fired technologies as they tend to be relatively labour-intensive installations.
- The installed CO_2 capture equipment cost and LCOE increased across all technologies in India. This was due to the consideration of a 30 per cent increase in equipment being imported into the country as well as India's typical coal heating value being very low, resulting in a greater capital cost.
- Costs increased across all technologies in Eastern Europe, primarily due to the increase in the reference coal price for the region.
- A 20 per cent increase in the technology cost in Australia which can be accounted for by the higher coal price utilised this year.
- A significant increase in the costs in Brazil, partially because of a lower labour rate being used in 2009. The revision of the coal type to one with a lower heating value also lead to a higher capital cost. Finally, additional costs associated with importing capital equipment contributed to the increase in CO_2 capture costs in Brazil.
- Only NGCC costs are displayed for Saudi Arabia, reflecting that there are no coal-fired power generation applications in the region.
- The breakpoint for the CO_2 credit value for oxyfuel has decreased from US$60/tonne of CO_2 in 2009 to US$55/tonne, which can be attributed to the lower coal costs offsetting the additional purification step included in this study. This analysis continues to indicate that oxyfuel still has the lowest CO_2 credit value breakpoint of approximately US$55/tonne of CO_2.
- The IGCC breakpoint, with respect to supercritical PC technology has decreased from $80/tonne in 2009 to $70/tonne of CO_2. This reflects the increase since 2009 in the LCOE and cost of CO_2 avoided and captured for IGCC with CCS.
- The cost breakpoint for the supercritical technologies is approximately $80/tonne of CO_2, an 11 per cent decrease from the 2009 breakpoint of $90/tonne of CO_2.
- The high breakpoint for NGCC technology has remained relatively unchanged at $112/tonne of CO_2, reflective of the lower CO_2 emission intensity of natural gas and higher cycle efficiency compared to coal-fired technologies.
- For the industrial processes, the incremental levelised product costs and the cost of CO_2 avoided/captured have increased by a small amount consistently across all applications.
- The cost to transport CO_2 is estimated to be between US$1-2 per tonne of CO_2, a decrease from US$3-4 per tonne of CO_2 in 2009. This is due to the reduction of the pipeline length in the reference case from 250km in 2009 to 100km.
- The contribution of storage cost to the LCOE was found to range from US$6-13 per tonne of CO_2 depending on whether the 'good' or 'poorer' reservoir option was considered.

Though minor changes in the costs of CCS across power generation and industrial applications have occurred, the costs of CCS still remain high. This is expected, given that it has only been 12 months since the initial Foundation Report Two, and major developments that have the potential to dramatically reduce the cost of CCS have not yet occurred.

Despite the costs of CCS being high relative to traditional power generation and industrial facilities, it is important to consider that these traditional methods currently emit large amounts of CO_2 into the atmosphere. Given the current and anticipated restrictions on facility emissions, these facilities will not be allowed to continue to operate as they have in the past.

The high costs of CCS as identified in this study should be considered with other low emission technologies to allow consideration of approaches to low emission power and industrial production. Further, if CCS is compared against the anticipated cost that may be imposed on facilities for emitting CO_2 it is likely to appear more competitive in a low carbon market.

2 INTRODUCTION

2.1 The importance of CCS

The successful development and widespread deployment of Carbon Capture and Storage (CCS) is considered by many key climate change stakeholders to be fundamental to achieving deep cuts in carbon dioxide (CO_2) emissions to atmosphere. Among a portfolio of responses, such as energy efficiency and renewable energy, CCS is required to contribute approximately 19 per cent of CO_2 emissions reductions globally by 2050 (International Energy Agency, 2008), if global emissions targets are to be achieved.

The business case to developing and deploying large-scale-integrated CCS projects (LSIPs) is challenging. One of the key challenges is the relatively high cost of CCS technology to capture, transport and safely store CO_2, compared to the same facilities without CCS. This is unsurprising, given that it costs more to capture, transport and safely store CO_2 as opposed to the current ‘business as usual’ scenario of venting CO_2 emissions to the atmosphere.

This report was commissioned by the Global CCS Institute as an update to the 2009 Foundation Report Two.

2.2 Background

The objective of this report is to build upon and update the cost estimates provided in ‘Report 2: Economic Assessment of Carbon Capture and Storage Technologies’ of the 2009 ‘Strategic Analysis on the Global Status of CCS’. As in 2009, the cost estimates are informed by WorleyParsons experience in the design, construction and operation of large infrastructure facilities that are likely candidates to apply CCS and direct engagement in assisting proponents to develop CCS projects. The cost estimates of storage are provided by Schlumberger and are similarly informed by their leading global position in this space.

Readers are encouraged to review the 2009 report if more background information and understanding is required. This can be found on the Global CCS Institute website at: http://www.globalccsinstitute.com/.

2.3 Scope

Building upon the 2009 study, the scope of this update is to consider the economics of CCS, based on 2010 capital, fuel and labour costs, and to assess several issues including:

- improving the regional localisation estimates;
- updating and enhancing capital cost estimates for power and a select range of industrial activities that could apply CCS; and
- updating the economic model (having regard for the two items above) to consider what, if any, material changes had occurred to the economics of CCS since 2009.

The additions to the scope were achieved by enhancing and improving operating cost estimates for capture facilities by improving fuel cost estimates at select locations and other key variables. Project location indices were also enhanced by providing greater specification that, where practicable, considered costs at a typical reference city level rather than a broad regional level.

2.4 Caveats and exclusions

As with the delivery of the Economic Assessment of Carbon Capture and Storage Technologies report (WorleyParsons, 2009), WorleyParsons and Schlumberger used its best endeavours to inform this update. Cost estimates used were observed in the global marketplace for developing large and often complex infrastructure projects and the costs of drilling for hydrocarbon were used as analogues for the cost of storage. US Gulf Coast (USGC) was the reference location.

The authors caution that when comparing costs, it is important to understand the purpose of the presented costs; are they presented to compare the costs between different technologies, or to inform how much a specific project will cost. There are several studies (e.g. the NETL Bituminous Baseline Study) which provide valuable information regarding the comparative costs of CCS technologies and the factors that impact these costs. The Global Carbon Capture Storage (CCS) Institute costing methodology and the studies prepared using it, fall into this group. These studies are typically poor predictors of project costs because they cannot accurately account for the variation in site and owner specifications included in a real project cost. Alternately, reported project costs, for specific projects, are poor sources for comparing technology costs. By the time the costs of a project are reported, only the cost of a single technology is presented which takes into account site specific requirements and owner's preferences.

The authors recognise that the economics of CCS is the subject of much conjecture and debate. Much of the conjecture is founded upon differing studies providing different results. In many cases, different results arise because key variables such as capital and operating costs, location and cost year differ. Additionally, the basis of the costs, that is which costs are included, are often not well defined or overlooked. Indeed, it was largely because of this that the Global CCS Institute commissioned the original 2009 study in an effort to provide cost estimates based on transparent and consistent variables and assumptions. The authors caution readers that care is required when applying the results of the cost estimates provided in this report. The margin of error in this study is +/- 40 per cent and the significant impact that project location and preference for CCS technology type, for example, means that the economics of CCS projects needs to be assessed on a case-by-case basis. It is important to note that all project costs are specific to that project and the figures presented in this report represent 'ball park' cost estimates for developing CCS projects as at 2011.

Furthermore, the authors note that some recent studies on the economics of integrated gasification combined cycle (IGCC) capture facilities are documenting costs that are greater than those presented in this study. Analogously, some CCS stakeholders speculate that the cost of IGCC with CCS is prohibitive based on the findings of these studies. Caution needs to be taken in considering this issue. One finding of the work performed by the Global CCS Institute is the costs can vary significantly based on location specific factors such as labor rates, fuel costs, and fuel characteristics. Additionally, with high volatility in plant construction costs and few new coal fired power (without CCS) construction starts in locations, real project costs are difficult to gauge. Therefore, the suggestion of providing a reference plant cost without CO_2 capture, using the same basis, along side of the facility with capture is suggested to give a better indication of the costs of CCS.

2 INTRODUCTION (CONTINUED)

Additionally, more detailed engineering has been undertaken for large-scale IGCC plants with CCS than for other power generation applications. As a result, lower levels of definition for technical design and cost for oxyfuel combustion and post-combustion CO_2 capture technologies can be expected. Given that the cost estimates for IGCC increased as the projects were further defined across the asset lifecycle, it can be expected that cost estimates for the other capture technologies may also increase. In other words, the perception that oxyfuel combustion and post-combustion CO_2 capture are economically more viable than IGCC may not be observed when projects applying these technologies undergo more detailed evaluations in the future.

2.5 Following chapters

Chapter Three provides an overview of the methodology. Chapter Four presents the results and Chapter Five presents key conclusions and observations.

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE

3.1 Overview of the economic assessment methodology

This cost analysis of CCS projects is an update of the 2009 Foundation Report Two. Building upon the 2009 report, the methodology essentially assesses the capital and operating costs over the life of an investment necessary to meet CO_2 emission reduction goals. The goal of private sector developers is to select the CCS technology that maximises profits over the long run in a sustainable way.

The methodology selected to define the economics of CCS investments is based on using capital costs and operating characteristics from published sources; WorleyParsons' and Schlumberger's in-house database of actual cost data gained from undertaking numerous designs, installations and analyses of CCS projects; and other data from corporate, government and research stakeholders. These were updated to 2010 dollars.

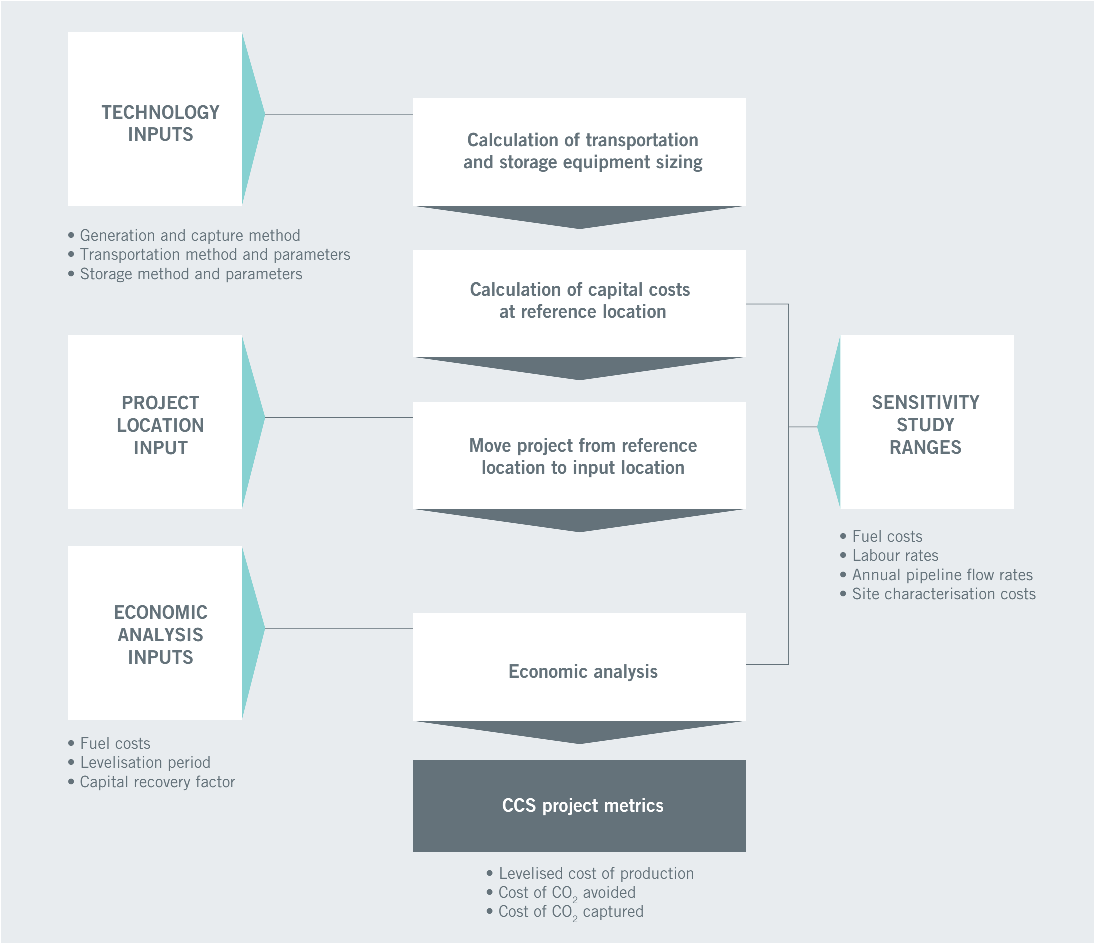
The methodology applied in this study combines these parameters to determine the appropriate metrics to be used in the economic analysis of CCS. This was conducted through:

- calculations of capital costs for the reference location;
- transposing the project to the selected location; and
- performing the subsequent economic analysis.

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

Figure 3-1 provides a flow chart showing, at a high level, the approach undertaken in the analysis.

Figure 3-1 Flowchart of methodology for CCS economic assessments



The CO_2 capture options considered for power generation include:

- post-combustion capture;
  - supercritical pulverised coal (PC) boiler
  - ultra-supercritical PC boiler
  - natural gas-fired combined cycle (NGCC).
- pre-combustion capture using IGCC; and
- oxy-combustion.

The application of CCS was considered on four industrial processes:

- blast furnace production of steel;
- cement kiln/furnaces;
- natural gas processing; and
- fertiliser production (ammonia).

While there are several methods of transporting CO_2 to a storage site including trucking and shipping, this study consider only the costs involved in pipelining as a means of CO_2 transport. To meet the G8 timeframes it is more than likely that transportation by pipeline will be the preferred approach, given the large volumes of CO_2 that will need to be transferred.

The 2009 study found that while the largest cost component in the CCS value chain was with the capture component, the CO_2 storage component of the value chain represents the greatest uncertainty. To model this uncertainty, the 2010 study provides a range of scenarios for 'good' and 'poorer' storage characteristics across a range of 3Mtpa and 12Mtpa reservoir capacities. This is discussed further in section 3.8.

As there have been no extensive changes in the economic and assessment methodology, refer to Foundation Report Two for the comprehensive description of the methodology. The metrics used to compare the costs of CCS projects have remained unchanged, with costs being presented in the form of:

- levelised cost of production;
- cost per tonne of CO_2 captured and injected; and
- cost per tonne of CO_2 avoided.

3.2 New methods used in the 2011 update

A change to the methodology occurred in the adjustment of process parameters of heat rate, CO_2 emissions and CO_2 capture according to regional coal composition and emissions requirements. This resulted in changes to the capital and operating and maintenance (O and M) costs for the capture facilities. This change improved the granularity of the estimates and analyses for the discrete regions given that:

- process design for coal-fired facilities is strongly dependent on local conditions including fuel composition, emissions regulations, climate and availability of water for cooling;
- design impacts sizing of equipment and thus capital costs;
- the heat rate of facilities increases with decreasing coal rank (heating value), therefore this increases the amount of fuel required and potential change in fuel costs; and
- the CO_2 emission intensity change relates to changes in fuel, potential impact on cost of CO_2 capture and avoided.

The adjustment of the process parameters was undertaken by:

- conducting a literature/study review of facility designs with different coal ranks;
- determining the heat rate and cost trend variations from reference coal designs. Trends described as simple functions from reference coal composition (Pittsburgh No. 8); and
- the adjustment of the capture technology costs at the reference location and then moving these to the region of interest.

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

3.3 Update of reference facility costs to 2010

The overnight capital costs used in the 2009 report were revised to early 2010 US dollars. Over the span between the reporting periods, the equipment costs have increased on the order 1 per cent while the labour costs have increased 0.5 per cent. Table 3-1 and Table 3-2 provide the operating parameters and updated capital costs used in the economic analysis. In Table 3-2, the cost of oxy-combustion without capture is set to zero based on that oxy-combustion is not considered without CCS.

A key change from the 2009 approach for CCS on the oxyfuel combustion power generation has been implemented. CCS on this facility now considers an additional purification step of the CO_2 to increase the CO_2 purity to greater than 95 per cent.

Table 3-1 Electric power generation (supercritical, ultra-supercritical and IGCC) facility parameters with and without capture.

		PC supercritical		Supercritical 2		Ultra-supercritical		IGCC	
	CO_2 Capture	No	Yes	No	Yes	No	Yes	No	Yes
	Fuel	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Gross power output	MW	580	663	580.2	661.1	576.6	644.4	748	694
Auxiliary power	MW	30	117	30.2	111.1	26.6	94.4	112	176
Net power output	MW	550	546	550	550	550	550	636	517
Net plant HHV efficiency	%	39.10%	27.20%	39.4	28.3	44.6	33.2	41.10%	32.00%
Net plant HHV heat rate	GJ/MWh	9.20	13.22	9.14	12.73	8.07	10.83	8.76	12.61
CO_2 generated	tonne/hr	442	631	440	613	389	521	479	470
CO_2 emitted	tonne/hr	442	63	440	61	389	52	479	47
CO_2 captured	tonne/hr	0	568	0	551	0	469	0	423
Emission intensity	kg/MWh	804	115	800	112	707	95	753	90
Plant capital overnight costs ($)									
CC equipment	x1,000	539,576	957,610	542,507	950,517	559,043	930,710	948,200	962,087
CC materials	x1,000	49,823	64,954	49,079	62,080	47,287	58,829	74,721	73,827
CC labour	x1,000	276,417	437,869	275,494	449,302	267,061	422,973	256,759	296,617
Eng. CM HO & fees	x1,000	78,055	133,336	77,810	133,053	78,074	128,088	104,631	113,334
Process contingency	x1,000	0	63,711	0	61,096	40,686	104,045	55,227	74,764
Project contingency	x1,000	111,985	234,026	111,926	235,789	114,883	227,726	224,927	244,510
Total	x1,000	1,055,857	1,891,506	1,056,815	1,891,836	1,107,033	1,872,371	1,664,464	1,765,138
Total overnight	$/kW	1,919	3,464	1,921	3,440	2,013	3,404	2,618	3,413
Variable O&M ($)									
VOM equipment	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOM materials	$/MWh	3.19	6.03	3.13	6.07	2.70	5.07	1.40	2.10
VOM labour	$/MWh	1.63	2.89	1.51	2.88	1.63	2.77	3.15	3.82
Total	$/MWh	4.82	8.92	4.64	8.95	4.34	7.84	4.55	5.92
Fixed O&M ($)									
FOM equipment	x1,000	0	0	0	0	0	0	0	0
FOM materials	x1,000	10,181	17,974	10,206	18,021	10,226	17,334	26,656	26,342
FOM labour	x1,000	9,197	11,727	9,716	10,478	9,205	10,367	11,636	12,127
Total	x1,000	19,378	29,701	19,922	28,499	19,431	27,701	38,292	38,469

Table 3-2 Electric power generation (oxy-combustion and NGCC) facility parameters with and without capture.

		Oxy-combustion supercritical		Oxy-combustion ultra-supercritical		Oxy-combustion ITM supercritical		NGCC	
	Capture	**No**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**	**Yes**
	Fuel	**Coal**	**Coal**	**Coal**	**Coal**	**Coal**	**Coal**	**NG**	**NG**
Gross power output	MW	NA	786	NA	759	NA	688	570	520
Auxiliary power	MW	NA	236	NA	209	NA	138	10	38
Net power output	MW	NA	550	NA	550	NA	550	560	482
Net plant HHV efficiency	%	NA	29.3	NA	33	NA	29.3	50.80%	43.70%
Net plant HHV heat rate	GJ/MWh	NA	12.30	NA	10.92	NA	12.27	7.09	8.24
CO_2 generated	tonne/hr	NA	592	NA	525	NA	560	202	202
CO_2 emitted	tonne/hr	NA	0	NA	0	NA	47	202	20
CO_2 captured	tonne/hr	NA	592	NA	525	NA	514	0	182
Emission intensity	kg/MWh	NA	0	NA	0	NA	85	362	42
Plant capital overnight costs ($)									
CC equipment	x1,000	NA	851,291	NA	835,378	NA	950,517	245,193	391,048
CC materials	x1,000	NA	61,530	NA	60,532	NA	62,080	23,710	28,771
CC labour	x1,000	NA	503,652	NA	468,571	NA	449,302	58,152	105,552
Eng. CM HO & fees	x1,000	NA	130,217	NA	124,831	NA	133,053	29,435	47,283
Process contingency	x1,000	NA	53,683	NA	68,832	NA	61,096	0	33,450
Project contingency	x1,000	NA	195,215	NA	185,014	NA	235,789	41,892	91,356
Total	x1,000	NA	1,795,588	NA	1,743,157	NA	1,891,836	398,382	697,460
Total overnight	$/kW	NA	3,265	NA	3,169	NA	3,440	711	1,447
Variable O&M ($)									
VOM equipment	$/MWh	NA	0.00	NA	0.00	NA	0.00	0.00	0.00
VOM materials	$/MWh	NA	3.44	NA	3.05	NA	3.36	0.48	1.01
VOM labour	$/MWh	NA	2.75	NA	2.68	NA	2.46	0.69	1.29
Total	$/MWh	NA	6.19	NA	5.73	NA	5.82	1.18	2.30
Fixed O&M ($)									
FOM equipment	x1,000	NA	0	NA	0	NA	0	0.00	0.00
FOM materials	x1,000	NA	17,207	NA	16,774	NA	15,417	4,412.31	7,060.31
FOM labour	x1,000	NA	10,346	NA	10,276	NA	10,053	3,411.58	4,560.27
Total	x1,000	NA	27,553	NA	27,050	NA	25,470	7,823.89	11,620.57

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

3.4 Regional specific factors

This update revises factors for moving the capital costs from the reference location to the location of interest and is described in section 3.4.1. The inclusion of region specific fuel information is described in section 3.4.2.

3.4.1 Development of regional cost indices

To support conversion of the reference case costs from USGC to location specific costs (expressed in US dollars) for the selected cities/countries, conversion indices were developed for three major cost elements. These include imported equipment and materials, locally sourced equipment and materials, and labour. The conversion indices were developed using data from Richardson Products' International Cost Factor Location Manual 2009-2010 Edition. Land cost within a region is difficult to assess and is strongly dependent on the specific location within a region and the current land use. Therefore, the land cost transfer index, specifically used with the capital costs for the pipeline for CO_2 transportation, was held constant and therefore assigned a transfer index of 1.00. The regional indices developed using these methods are listed in Table 3-3.

Table 3-3 Regional indices used to transfer projects from USGC to specific locations

	Capital and O&M Costs			
Region	**Equipment**	**Materials**	**Labour**	**Land/ROW**
ANZ				
Australia	1.21	1.21	1.58	1.00
Asia				
China	0.81	0.81	0.05	1.00
Japan	1.21	1.41	1.84	1.00
India				
India	1.27	1.11	0.26	1.00
Europe				
Euro Region (Germany)	1.19	1.16	1.33	1.00
Eastern Europe (Poland)	1.01	0.81	0.79	1.00
ME and Africa				
Saudi Arabia	1.27	1.21	0.35	1.00
South Africa	1.27	1.11	1.04	1.00
Americas				
Canada	1.08	1.01	2.16	1.00
United States	1.00	1.00	1.00	1.00
Brazil	1.16	1.16	0.97	1.00

The Imported Equipment and Materials index adds a factor for freight over USGC. Taxes and duties have been specifically excluded from the calculation.

The Locally Sourced Equipment and Material index represents the cost of the locally sourced items (expressed in US dollars) relative to USGC.

The labour index considers two key elements; the relative cost of labour (on a crew rate basis) and the relative labour productivity as compared to USGC.

In general, the equipment related to power projects was considered as an imported cost except in the case for countries with significant industry such as China.

The capital costs for power generation and capture were considered for the respective regions. Based on WorleyParsons experience, the China labour index was significantly greater than that previously reported and resulted in power plant capital costs greater than those typically reported. This higher than expected index is related to the urban locations used within the Richardson's manual. Generally, the setting of most power plants is in rural areas, and as a result the labour index for China was reduced to a value more inline with the previous report of 0.05.

The reader is cautioned that the calculated indices are based on very specific locations/cities, generally major metropolitan areas, and can vary considerably, particularly with respect to labour, depending on the actual project location. Additionally, the type of labour used; non-union, union, or work camps, can greatly impact the labour costs within a given region. Further, the locally sourced equipment and materials and labour indices will vary with changes in currency exchange rates.

3.4.2 Regional coal type and fuel costs

In addition to the update of the regional factors, typical coal types for each of the regions were selected to be utilised in the economic analysis. The coal selections were based on the information provided in Projected Costs of Generating Electricity (IEA, 2010) and WorleyParsons' experience. In general, obtaining the price paid by a generator for fuel is difficult and where this data is available, is found to vary significantly between facilities. The coal pricing approach for the regions was adopted from the Projected Costs of Generating Electricity in that for countries which produce coals, local coal prices were assumed while for non-coal producing countries international market prices were assumed. The local coal prices were determined through the review of the literature such as national energy surveys, the Projected Costs of Generating Electricity, and in the case of the United States, a database of delivered fuel costs. The regional natural gas prices were determined through similar methods. A summary of the coal types and coal and natural gas prices used in this study are provided in Table 3-4.

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

Table 3-4 Coal types and prices used for coal and natural gas per region

Region	Coal	Coal Heating Value, HHV	Coal price (US$/GJ)	Natural gas price (US$/GJ)
ANZ				
Australia	Australian Black	24.8	1.45[1]	7.58[5]
Asia				
China	China Bituminous	24.1	3.58[2]	4.53[5]
Japan	Australian Export, Bituminous	33.3	4.95[3]	11.09[5]
India				
India	High Ash Indian Bituminous	12.6	4.44[4]	4.20
Europe				
Euro Region (Germany)	German Brown	10.5	1.37[5]	9.76[5]
Eastern Europe (Poland)	Polish Brown	10.1	0.67[6]	9.76[5]
ME and Africa				
Saudi Arabia	NA	NA	NA	2.00
South Africa	South African Coal	18.2	0.82[5]	9.76[5]
Americas				
Canada	Canadian Sub-bituminous	28.9	0.91[7]	7.40[5]
United States	Bituminous IL No #6	27.1	2.61[8]	7.40[5]
Brazil	High Ash Brazilian Bituminous	10.4	1.85[5]	7.71[5]

Notes:

1 Average of black coal prices, 'Fuel resource, new entry and generation costs in the NEM,' (ACIL Tasman, 2009).

2 Coal price assumed in the IEA publication in $/tonne, compares to average fuel price presented in paper, 'CO_2 capture from coal-fired power plants in China', (NZEC, 2009) of $3.50/GJ. Comparable to price reported by WorleyParsons China Office of $85-100/tonne.

3 Import price of coal to Japan in Q1- 2010.

4 Midrange of delivered coal price (range $48/t to $64/t) to power plants from 'Coal Initiative Reports, A Resource and Technology Assessment of Coal Utilization in India' (Chikkatur, 2008).

5 Coal and Natural Gas price assumed in 'Projected Costs of Generating Electricity, 2010 Edition' (IEA, 2010).

6 Data from WorleyParsons based on work in Eastern Europe.

7 EIA data, Low price is reasonable based on the vertical integration and coal fired generation in Canada; see Natural Resources of Canada, www.nrca.gc.ca

8 EIA average Form 923 (Power Plant Operations Report, delivered coal prices to power plants, EIA 2009e) data for 2009.

3.5 Power generation, CO_2 capture and coal type

The coal type used for power generation and its characteristics can vary significantly between locations and impact the design of the power generation facility. Typically in selecting the coal to be used as a fuel, economic analyses are performed based on a specific location, the available coals and their cost. To account for the potential variation in coal types between regions, correlations were developed between a factor to relate the capital costs, plant heat rate, and O&M costs to the coal rank and facility designs. These factors were used to adjust the reference plant operating parameters and costs, so that they would be representative of a typical coal used in the regions.

The following paragraphs provide a description of the methodology used to derive the correlations between performance and cost implications on various power generation technologies and on a variety of fired coals. The power generation technologies include supercritical (SC) and ultra-supercritical (USC) PC power generation with/without CO_2 capture, IGCC with/without CO_2 capture and SC and USC oxyfuel combustion power generation.

3.5.1 General methodology

To obtain the correlations, plant performance and cost data for different coals were extracted from various publications and the WorleyParsons database. The data was then screened and analysed. The data was selected for producing the correlations only when it was from a single study and covered a relatively wide range of coals, typically one or two bituminous coals, one sub-bituminous coal and/or a lignite coal. Selecting studies that consider multiple coal types at the same location guarantees the data is on the same basis. The factor correlations were developed by considering the ratio of a parameter, that is capital cost, at different coal heating values, to a reference coal heating value of 30.8MJ/kg, the heating value of Pittsburgh No. 8 coal. Extrapolation or interpolation was applied in some cases when necessary. The best fit curves and correlation equations were found through selected data series using regression analysis techniques in Excel (Trendline function in Chart).

The correlation equations present the percentage change in plant performance or capital cost as a function of coal heating value from the reference coal heating value. The higher heating value (HHV) was used throughout this work. It is acknowledged that coal constituents have impacts on plant performance and cost to different degrees of extent. However, only HHV is used to represent coal categories in this study.

If multiple data sets from different sources were available, the correlation equation/curves were based on all data, which basically averages the selected parameters and hence reflects generic correlations. If the correlation equations were developed based on a single data set due to limited information, the correlations reflect the conditions defined in referred studies. In such case only the studies with relatively generic design conditions were chosen.

3.5.2 Assumptions

The following assumptions were also made to derive the correlations between performance and cost implications on various power generation technologies and on a variety of fired coals.

General

a) Correlation equations are developed by data fitting technique if multiple data sets are available, which basically averages the subject parameters and hence reflects only generic trend of coal heating value. If the correlation equations are developed by single data set due to limited info availability, the equations will only reflect the data based on specific conditions of the referred study.

b) All the technical and cost data is based on studies in US region. It should be acknowledged that cost varies with the plant site, significantly sometimes. The studies are either public or from WorleyParsons database.

c) The data collected is based on the consistent system configurations for US region, and does not intend to reflect specific region or country's pollutant emission requirements and other constraints such as water.

d) PC plant data is based on SC and USC plant. The IGCC plant data is based on Shell Technology only considering it is relatively abundant data for different coal including low rank coal.

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PC case

a) All the SC and USC PC plants analysed with or without CO_2 capture are equipped with flue gas desulphurisation (FGD) for sulphur reduction and selective catalytic reduction (SCR) for NOx reduction from the stack.

b) The SC or USC PC plant performance curve does not necessarily reflect the impact of sulphur content in coal on SC steam condition. The PC heat rate curves are based on consistent steam condition for the range of coal.

c) All cases with CO_2 capture efficiencies are assumed to be approximately 90 per cent.

d) The SC/USC PC plant performance (heat rate) of each data set is based on new plants specifically designed for different coals.

e) The SC PC plant capital cost is based on sites in US. It should be acknowledged that cost varies with the plant site, dramatically sometimes.

f) PC FGD option data was based on FGD using limestone or lime in US corresponding to coals.

IGCC case

a) While specific component selection has an impact on IGCC system performance (for example an IGCC choosing Selexol as acid gas removal (AGR) system has slightly different performance from one choosing Amine system), the performance curve intends to reflect such differences.

b) IGCC with or without CO_2 capture heat rate comparisons are based on Shell technology (dry feed). It should be noted that for other technologies, the comparison result may change to different degrees of extent.

Oxyfuel PC plant

a) Based on SC/USC pulverised coal power plants (24.1MPa/599°C/621°C, 3500 psig/1110°F/1150°F)

b) The plants are equipped with low NOx burner (LNB)/overfire oxygen (OFO)/flue gas recirculation (FGR) and FGD

c) Oxygen (95 per cent pure) used for combustion is produced from cryogenic air separation unit (ASU) system.

d) CO_2 specification is for storage in saline formation (raw combustion product produced using 95 per cent oxygen and dehydrated to 0.015 per cent (by volume) H2O).

e) Assume the efficiency difference for an oxyfuel boiler firing different coal is similar to the difference for an air fired boiler firing different coal while the oxyfuel boiler efficiency has slightly higher efficiency.

f) CO_2 compression uses integrally geared, multistage centrifugal with indirect water intercoolers.

FGD option factor

a) FGD performance and cost comparisons are based on a SC PC plant firing Illinois #6 bituminous coal with a wet limestone forced oxidation positive pressure absorber.

Cooling options factor

a) The factor is based on mechanical draft wet cooling options and 100 per cent dry cooling.

b) Comparison is assumed on average annual ambient temperature of about 16°C (annual average). The performance impact is of average corresponding to the ambient. It should be noted that ambient temperature has significant impact on the performance when the plant switches between wet and dry cooling options at high temperature, for instance 0°C.

3.5.3 Correlations developed

To facilitate presentation, the correlations were given in the form of a ratio of studied plant performance/cost to a referred plant performance/cost as a function of heating value difference between studied coal and the referred coal heating value. The performance and cost of plants firing bituminous coal, i.e. Pittsburgh No. 8 coal, was used as the referred data point. Correlation diagrams between net plant heat rate (HHV) and coal heating value, and plant capital costs and coal heating value for a SC PC plant without CO_2 capture are illustrated in Figure 3-2 and Figure 3-3.

Figure 3-2 Heat rate factors as a function of coal heating value

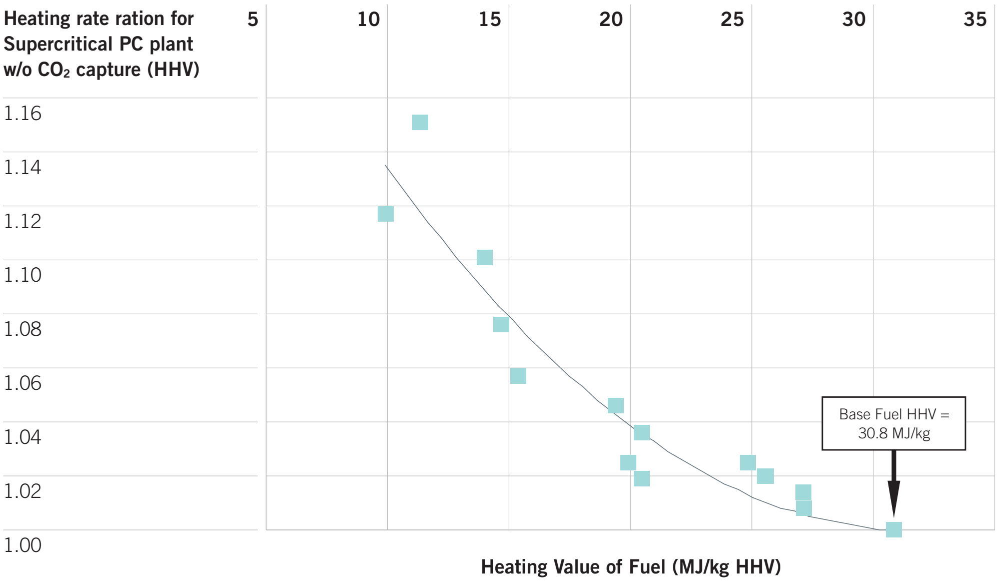

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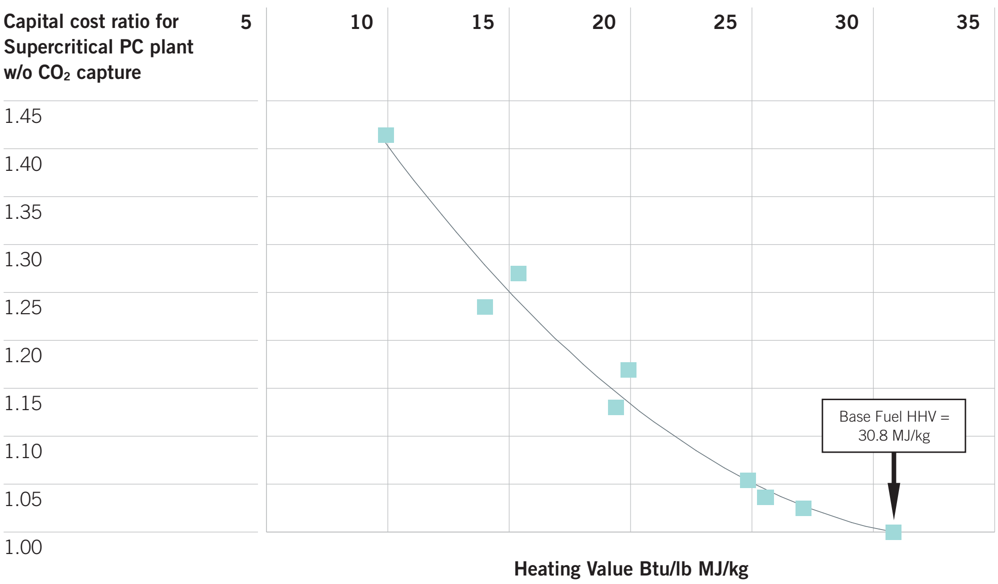
Figure 3-3 Capital cost factors as a function of coal heating value



Specifics regarding the data sources and specifics of the analyses for the various technologies are provided in the following sub-sections.

PC power plant

Correlations between performance/capital cost and coal heating values for SC-PC power plant without CO_2 capture were derived using data from several public studies and a confidential WorleyParsons study (Holt, N & Booras, G 2007; WorleyParsons 2002; EPA 2006; WorleyParsons 2009a; DOE/NETL 2007; WorleyParsons 2009b). Performance and capital cost correlations for SC-PC power plant with CO_2 capture were developed using data from various reports (WorleyParsons 2009a; DOE/NETL 2007; WP 2009b). Information were applied in correlations between coals and O&M cost for SC PC power plants with and without CO_2 capture (DOE/NETL 2007; WorleyParsons 2009b).

For the case of heat rate correlation of USC-PC without CO_2 capture, data from a WorleyParsons report (WorleyParsons 2009a) was used. Due to the sparse information the correlations for USC power plant capital cost, O&M cost, the data for SC PC plants were adopted. USC-PC plants have different capital and O&M costs from SC-PC plants. However using the ratio of the cost mitigates the impact to some extent.

IGCC power plant

Correlations for IGCC power plant were derived based on Shell coal gasification technology because of its suitability to relative wide range of coals and good information availability.

Data from several sources were used to develop the correlations for IGCC plant with and without CO_2 capture (WorleyParsons 2009a; DOE/NETL 2007; WorleyParsons 2009b; Maurstad et al 2006).

Oxycombustion power plant

Oxycombustion technology used for power generation is still in development. There is currently little published information on the impact of different coals on the plant performance and costs. However, many studies for power generation utilising oxycombustion boiler for single specific coal have been done, and some studies from technology vendors indicate that a oxycombustion PC boiler has similar or slightly higher efficiency as a conventional PC boiler, and the oxycombustion PC power plant essentially has the same system and equipment as the conventional PC power plant except the boiler island (US DOE 2008a; DOE/NETL 2006; DOE/NETL 2001). With these considerations in mind, the performance and cost for an oxycombustion power plant were estimated based on the performances and costs of an SC oxycombustion power plant based on a specific coal (US DOE 2008a) and a conventional SC PC power plant firing different coals (DOE/NETL 2007; WorleyParsons 2009b). The correlations for SC and USC PC oxycombustion power plants then were derived from these estimated performance and costs.

Flue gas desulphurisation and wet/dry cooling design options

The impact of a SC PC power plant with or without a FGD on cost and performance was estimated. The derived factor (percentage) was based on information from the 'Cost and Performance Baseline for Fossil Energy Plants' (DOE/NETL 2007). The study utilising wet limestone forced oxidation type FGD.

The impact for switching wet cooling to drying cooling on the performance and cost of PC and IGCC power plants were estimated based on information from various reports (DOE/NETL 2007; WorleyParsons 2007; Power, W.E 2005; Power, W.E 2009). It should be noted that the design ambient temperature may have significant impact on the performance and cost of a power plant. In this study the data was based on design ambient temperature of 60-65ºF, which is considered to be an annual average temperature.

3.5.4 Limitations of approach

The above approach is not intended to provide for detailed accounting of the coal type and process design requirements but rather a rapid method of assessing the impact of these parameters in an economic model. As illustrated these correlations are strictly empirical and should be treated as such. Limitations of this approach include:

- not considering variation in process designs which account for many interacting case specific factors;
- trends utilise coal heat heating as the primary driver for cost and heat rate changes, coal characteristics leading to coal heat rate are not necessarily considered; and
- impact of high coal ash content and ash composition/properties not included.

3.6 CO_2 capture from industrial processes

There were minimal changes made to the method in which the CO_2 capture cases for industrial processes were analysed. The capital and operating costs were updated from the 2009 figures, which resulted in an increase of approximately 1 per cent.

As with the initial economic assessment in 2009, the 2010 CCS economic analysis was applied to select industrial processes to determine the cost parameters for blast furnace steel production, cement production, natural gas processing, and fertiliser (ammonia) production. The specific

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

emission intensities, typical production rates, annual CO_2 flow rates, and other parameters from current commercial practice were used as a basis (where available) and are listed in Table 3-5. Steel and cement production require both capture and compression while natural gas processing and fertiliser production are processes that require CO_2 separation from a gas stream. Thus, these processes only need the addition of drying and CO_2 compression.

Table 3-5 Emissions intensities, processing parameters, and commercial application examples for industrial processes

	Blast Furnace	Cement	Natural Gas Processing	Fertiliser Production
CO_2 emission intensity	2tonne CO_2/ tonne steel	0.83tonne CO_2/ tonne cement	0.13kg CO_2/Sm^3 natural gas	0.57tonne CO_2/ tonne ammonia
Product production rate	40steel tonne/hour	40cement tonne/hour	1,100Sm^3/hour 46GJ/hour	46tonne ammonia/hour
Annual CO_2 flow of single plant (tonne/year)	706,000	296,000	1,000,000	194,000
Commercial example	No commercial operating facility	No commercial operating facility	Sleipner	Coffeyville gasification facility

The energy for capture (primarily solvent regeneration) and CO_2 compression can be obtained through heat or electricity generated by the system or through purchased power. This uncertainty can lead to difficulties in the interpretation of the analyses. In this assessment, the following assumptions were made.

- The cost of the energy to meet the auxiliary load was determined from the natural gas cost in the region with 50 per cent conversion efficiency.
- The CO_2 from the generation of heat or electricity used by the capture system was not included in the calculation.

The CO_2 flows from the individual industrial processes, less than 1Mt per year of CO_2, are smaller than those for standard power generation plants. Therefore, it was assumed that a multi-user pipeline and storage option would be available. For storage and transportation, costs of US$4/tonne of CO_2 and US$7/tonne of CO_2 were used, respectively. The basis for the cost is discussed in the following sections.

3.7 CO_2 transport

Report One from the 2009 Strategic Analysis work identified CCS projects around the world that are in operation or under development. The study also identified a subset of CCS projects that were classified as large-scale integrated CCS projects (LSIPs). Examination of this subset of LSIPs as part of the economic assessment update found that the average length of pipelines for the LSIPs was in the order of 100km. To reflect the activities occurring in the development of CCS projects globally, this distance for an onshore pipeline is used is estimating transport costs. This differs from the reference case assumption made in the 2009 economic assessment of 250km. The other process assumptions for CO_2 transport including inlet temperature and pressures remained unchanged.

3.8 CO_2 storage

As the 2009 study showed, the economics of CO_2 storage is dependent upon the geology of the target formation. The geology will drive the storage site selection and the site will drive the commerciality of commercial scale, integrated CCS projects. In this update, the “finding” costs applied are assumed to range from US$25 million in the ideal case to US$150 million or more depending on the geology. This is consistent with the 2009 study.

Given the high variability of geologic properties within a region, let alone across nations, the assumption was made that the 'reservoir' properties were identical across all the jurisdictions for which recent market costs were available (North America, Europe and Australia/New Zealand). This allowed for a direct comparison of potential storage costs over these regions and an understanding of what the key capital and operating costs are for each region. It was also assumed that all storage projects occur onshore, an assumption that avoids the highly variable costs of drilling offshore. A further assumption is that no EOR is possible as a means of revenue offsets for CO_2 storage. Thus, the storage scenarios allow for 'reasonable' comparisons. In cases where storage costs for CO_2 were not available, the costs of hydrocarbons exploration programs were used as analogues.

Furthermore, in order to treat the inherent uncertainty of storage, two case study scenarios were considered. The two cases were for a 'good' reservoir and a 'poorer' reservoir with either 3Mtpa or 12Mtpa injection scenarios modeled. These are presented in Table 3-6. In this case, the primary differences between the two reservoirs are the absolute permeability and the reservoir thickness.

Table 3-6 Geological and well properties for 'poorer reservoir' and 'good reservoir'

	Units	'Poor reservoir'	'Good reservoir'
Net thickness	m	5.0	15.0
Absolute permeability	md	150	400
Reservoir mid-depth	m	1700	1700
Initial pore gradient	bar/m	0.1002	0.1002
Temperature gradient	°C/100m	3.0	3.0
Surface temperature	°C	20	20
Fracture gradient	bar/m	0.136	0.136
Initial pore pressure	bar	170	170
Reservoir temperature	°C	71	71
Injection pressure limit (of FG)	–	90%	90%
Initial injection pressure	bar	208	208
Relative permeability	–	0.3	0.3
Drainage radius	m	762	762
Wellbore – radius	m	0.09	0.09
Total skin	–	2.5	2.5

For both these cases, the well counts at the start of the injection period and end of the injection period were calculated using a number of factors to control well count. It was assumed that no heating of the CO_2 was required upon delivery to the injection site (this may be a simplification which would require both power and compressors at the wellhead thus increasing capital (CAPEX) and operations and maintenance (OPEX) costs) and that the injection pressure was always maintained at 90 per cent of the fracture gradient thus reducing operational risk from injection induced fracturing. The drainage radius assumes that the CO_2 forms a circular pool ('pancake') at the injection point (that is, that the reservoir is wholly homogenous throughout all the injection points).

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

The analysis assumed that a suitable reservoir was located and characterised and that injection could commence once the capture plant was online. It was also assumed that the exploration and appraisal program that would start in late 2010 to prove up these sites (and others as a potential portfolio of storage options) was successful and that the locations would have been shown to have suitable seals and other geological factors that would allow for safe storage of CO_2 over the longer term. Thus, the analysis assumes that the developmental timeline for the storage site starts at the FEED phase to allow injection to commence from 2016 onwards. In both cases, 'finding costs' are included in the site selection and. Vertical injection wells are used in both cases as the standard. The evaluation did not consider stimulation by fracturing or deviated well placement that could increase injection rates. Such well design considerations would be considered after the site characterisation and the full field development program are complete.

This analysis required that the injection well pressure was below the fracture pressure (90 per cent of fracture pressure) which provides the first order constraint on potential storage volumes. CO_2 injection above the fracture pressure could increase well injectivity rates, but at the risk of fracturing the cap-rock. Thus, an accurate determination of the actual fracture pressure can only be derived from laboratory tests on new core samples from both areas. Another assumption is that sufficient pore space is available over the life of the injection operations.

This analysis required that the injection well pressure was below the fracture pressure (90 per cent of fracture pressure) which provides the first order constraint on potential storage volumes. CO_2 injection above the fracture pressure could increase well injectivity rates, but at the risk of fracturing the cap-rock. Thus, an accurate determination of the actual fracture pressure can only be derived from laboratory tests on new core samples from both areas. Another assumption is that sufficient pore space is available over the life of the injection operations.

As previously discussed in the 2009 Foundation Report Two, the key factor determining the cost of CO_2 storage is the 'reservoir permeability thickness product' ($k \cdot h$) since this determines the injectivity of the site and thus controls the well count needed for a given volume of CO_2.

As can be seen in Table 3-7 below, the final well counts required for each reservoir for both injection scenarios are as follows.

Periodically new wells will need to be brought online in the poor reservoir to allow for the constant injection volume to be maintained on an annual basis. This is due to the 'back pressure' exerted by the reservoir as it fills with CO_2, meaning that the original injection volume on the initial injector wells will decrease over time, thus necessitating new wells for constant volumetric injection.

Table 3-7 Well counts for 'Poor reservoir' and 'Good reservoir'

Reservoir quality injection volume	3Mtpa	12Mtpa
'Poor reservoir'	16	61
'Good reservoir'	2	8

Regional cost comparison

Recent data on the costs for CO_2 storage were available from Australia/New Zealand, Europe, and North America for CO_2 injection wells and associated services. These are listed in Table 3-8. Whilst proprietary data was available for China, confidentiality issues prevented the release of this information. As a result, Australia and New Zealand (ANZ) was used as a proxy for this region.

Table 3-8 Regional costs for CO_2 storage

Regional Costs (in 2010 US$)		ANZ	Europe	US
3D Seismic survey	mln US$/svy	18	25	18
Deep monitoring well costs	mln US$/well	6	6	5
Shallow monitoring well costs	mln US$/well	0.50	0.70	1
Injection well costs	mln US$/well	7	7	10
Injection well abandonment costs & rehab	mln US$/well	1	0.70	1
Monitoring well abandonment costs & rehab	mln US$/well	0.50	0.70	0.5
In-field flow lines	mln US$/well	0.24	0.35	0.25
Drilling cost escalation per annum	%	7 %	5 %	5 %
Well-related OPEX	% of DrillEX	5 %	5 %	5 %
Monitoring OPEX	mln $/yr	0.10	0.14	0.10
Fees & Rents OPEX	mln $/yr	0.10	0.14	0.10

There is little headline difference in the well costs between each of the regions. This recognises that the costs estimates for the complete study is in the order of +/- 40 per cent and indeed the similarity of the costs can be taken as an indication that the market for well services/rigs is worldwide. Thus, companies will seek to move staff and assets to areas of demand.

3.9 Summary of process and economic modelling assumptions

The default assumptions used for the reference CCS system during the assessments of the various technologies are listed in Table 3-9. As described in the previous sections within this chapter, primary changes from the initial report include revised parameters for the storage reservoir properties and the decrease of the pipeline length from 250km to 100km.

3 METHODOLOGY FOR CCS ECONOMIC ANALYSIS UPDATE (CONTINUED)

Table 3-9 Process modelling and financial assumptions for reference case

Capital cost estimate basis:			
	Constant 2010 US dollars (2010 US$)		
	The reference location is the US Gulf Coast.		
	Labour is based on non-union rates.		
CO_2 capture			
	Power generation: results listed for supercritical, oxy-combustion, IGCC, and NGCC technologies, system design parameters listed in Table 3-1 and Table 3-2.		
	Industrial processes: natural gas processing, cement production, blast furnace production of steel and fertiliser (ammonia) production.		
Transportation: pipeline			
	CO_2 pipeline length:	100km	
	CO_2 pipeline inlet temperature:	25°C	
	CO_2 pipeline inlet pressure:	20.2MPa	
	CO_2 pipeline outlet pressure:	15.3MPa	
Storage: saline aquifer (reference case was for 'good reservoir')			
	Reservoir pressure	17MPa	
	Reservoir thickness	15m	
	Reservoir depth	1,700m	
	Reservoir absolute permeability	400mD	
	Site screening and evaluation	US$66,000,000	
Financial: general			
	Levelisation period	30 years	
	Owners' costs	15%	
	AFUDC rate	9%	
	Labour multiplier	1	
	Coal cost	2.61US$/GJ	
	Natural gas cost	7.40US$/GJ	
Financial: cost of capital		Per cent	Rate
	Debt	40%	6%
	Equity	60%	12%
	Tax rate for debt interest deduction	33%	
Financial: escalation rates			
	Fixed O&M cost escalation rate	0%	
	Variable O&M cost escalation rate	0%	
	Real CO_2 emissions escalation rate	0%	
	Real fuel escalation rate	3%	

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS

An economic comparison of projects can be performed using the methodology and templates reviewed and developed in Chapters Two and Three, respectively of Foundation Report Two. Additionally, sensitivity analyses are also included in this evaluation to determine the range of results and their dependence on key cost components and design assumptions.

The assumptions used for the reference CCS system during the assessments of the various technologies are listed in Table 3-9. The following sections provide an update of the results.

4.1 Capture of CO_2

The methodology developed was applied to power generation and select industrial processes to determine the levelised production costs (US$/unit of product), cost of CO_2 avoided, and the cost of CO_2 captured.

4.1.1 Power generation

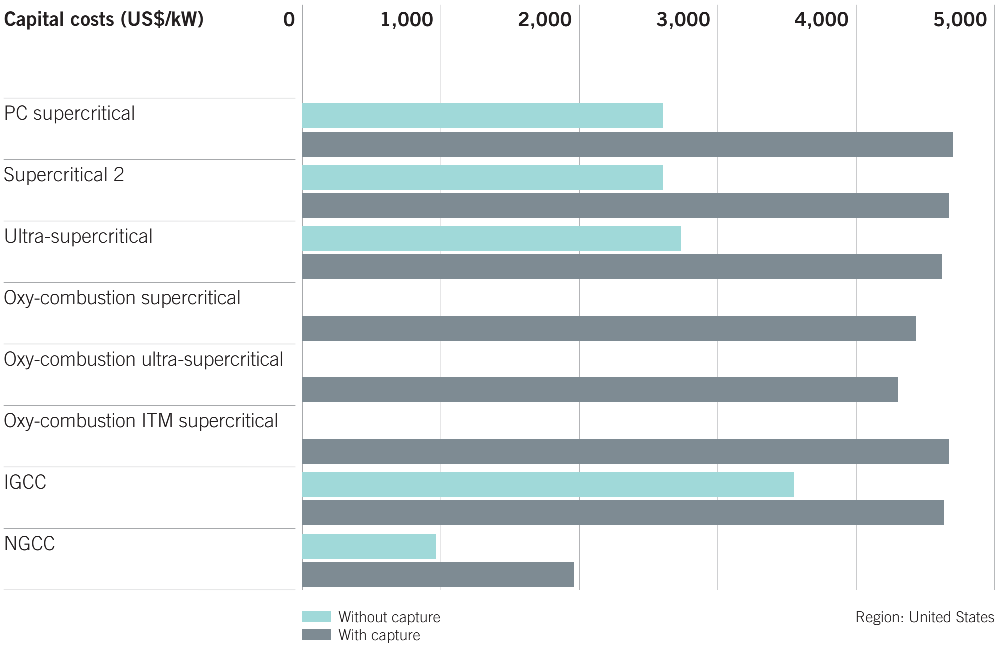
Capital costs

The impact of CCS on the cost of new electric power generation facilities was the first set of cases to be reviewed using the model developed. The parameters for the facilities are listed in Table 3-1 and Table 3-2, and under the base case assumptions listed in Table 3-9. The capital costs, including the owners' costs, for the CO_2 capture portion of the CCS system are compared on a $/kW basis in Figure 4-1 for first-of-a-kind (FOAK) systems (note that transportation and storage cost components are not included). FOAK systems are innovative and inherently involve greater uncertainty and therefore costs. Experience gained from these plants (such as design and operation) will generate learnings which will reduce the uncertainty and hence the costs. As these experiences increase, the cost reductions (for example, through process optimisation) result in nth-of-a-kind (NOAK) plant estimates.

For the non-CO_2 capture of PC supercritical and ultra-supercritical cases, there is a small cost increase related to the material requirements for the higher steam conditions. This capital cost is potentially recovered through lower fuel costs related to the greater efficiency of the ultra-supercritical unit. The selection of plant efficiency, as determined by the steam conditions, must consider a balance between the capital and fuel costs. Based on the small change in the overnight capital costs at the reference location, there is only a small increase in these values compared to the 2009 report.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

Figure 4-1 Installed costs for 550MW net generation and CO_2 capture facility (FOAK)



Levelised cost of electricity

Capital costs presented above, along with transportation and storage capital costs (based on matching the captured CO_2 flows), were used as inputs to the economic assessments. The LCOEs for FOAK and NOAK plants are presented in tabular form in Table 4-1 and graphically in Figure 4-2.

The cost parameters calculated from the LCOEs, the cost of CO_2 avoided and cost of CO_2 captured (including transportation and storage), in the economic assessment are provided for FOAK and NOAK units in Table 4-2 and shown graphically for FOAK units in Figure 4-3.

The costs of LCOE and CO_2 avoided and captured have decreased slightly since the 2009 report. This is likely to be a reflection of the revised fuel costs for this update.

Table 4-1 Breakdown of LCOE for technologies with and without CCS for FOAK and NOAK plants

	PC supercritical	PC supercritical 2	Ultra-supercritical	Oxy-combustion supercritical	Oxy-combustion ultra-supercritical	Oxy-combustion ITM supercritical	IGCC	NGCC
LCOE without capture ($/MWh)								
Generation	76	76	73	NA	NA	NA	90	88
Transportation	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0
Total	**76**	**76**	**73**	**NA**	**NA**	**NA**	**90**	**78**
LCOE with capture for FOAK ($/MWh)								
Generation and capture	124	121	113	114	107	116	116	115
Transportation	1	1	1	1	1	1	1	1
Storage	6	6	6	6	6	6	6	6
Total	**131**	**129**	**120**	**121**	**114**	**123**	**123**	**123**
LCOE with capture for NOAK ($/MWh)								
Generation and capture	122	119	109	112	104	114	113	114
Transportation	1	1	1	1	1	1	1	1
Storage	6	6	6	6	6	6	6	6
Total	**129**	**127**	**117**	**119**	**112**	**121**	**121**	**121**

Note: The steam conditions of the ultra-supercritical technologies presented are beyond those typical used in the industry today and therefore should be considered emerging technologies. The initial deployment of this technology will be strongly dependent on the specific site and available coal characteristics. Therefore, in the near term, the PC supercritical should be considered as the reference case.

Table 4-2 Cost of CO_2 avoided and captured for FOAK and NOAK plants

	PC supercritical	Ultra-supercritical*	Oxy-combustion supercritical	Oxy-combustion ultra-supercritical	Oxy-combustion ITM supercritical	IGCC	NGCC
FOAK							
Cost of CO_2 avoided ($/tonne CO_2)	81	62	57	47	59	67	107
Cost of CO_2 captured ($/tonne CO_2)	53	55	42	43	47	39	90
NOAK							
Cost of CO_2 avoided ($/tonne CO_2)	78	57	54	44	57	63	103
Cost of CO_2 captured ($/tonne CO_2)	52	52	41	42	45	38	87

Notes: In the cost of CO_2 avoided calculations, for the coal-fired power generation, SC-PC without CCS was used as the reference case and for the NGGC without CCS was used as the reference case for NGCC with CCS. In select previous studies (such as DOE/NETL 2007) , the cost of CO_2 avoided has been calculated with the reference plant selected as the similar technology without CCS. For IGCC, under this assumption, the FOAK and NOAK costs of CO_2 avoided are $51/tonne and $50/tonne, respectively.

* With the assumption that ultra-supercritical technology, with the designed steam conditions, is available for CCS, this becomes a low cost option for the reference facility and thus is used for the reference plant in the cost of CO_2 avoided calculation.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

Figure 4-2 Comparison of LCOE for reference generation, with and without CCS in USGC

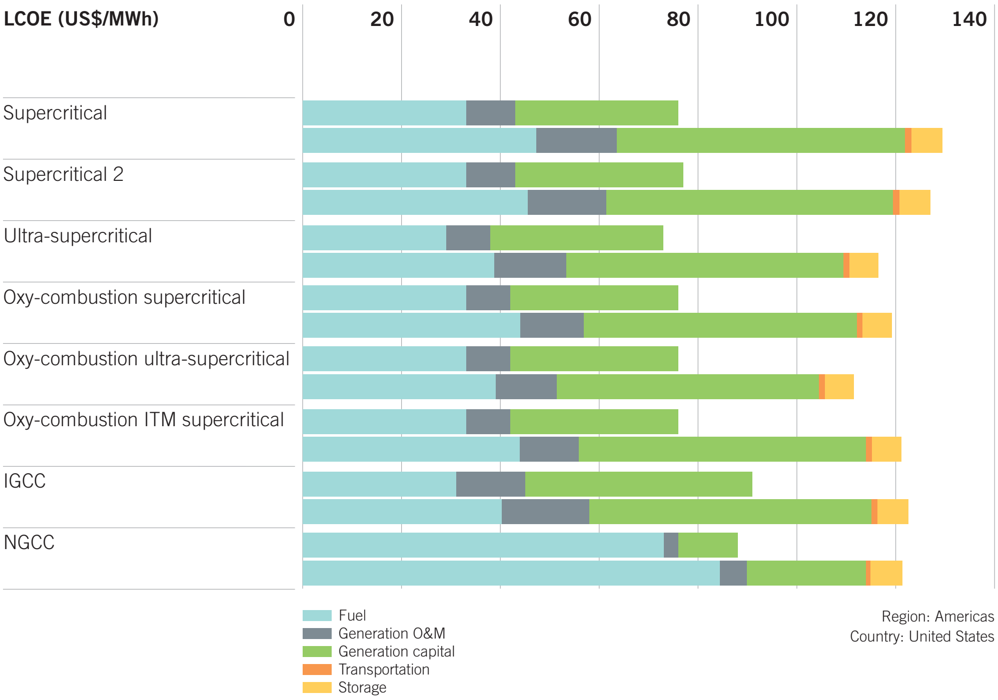
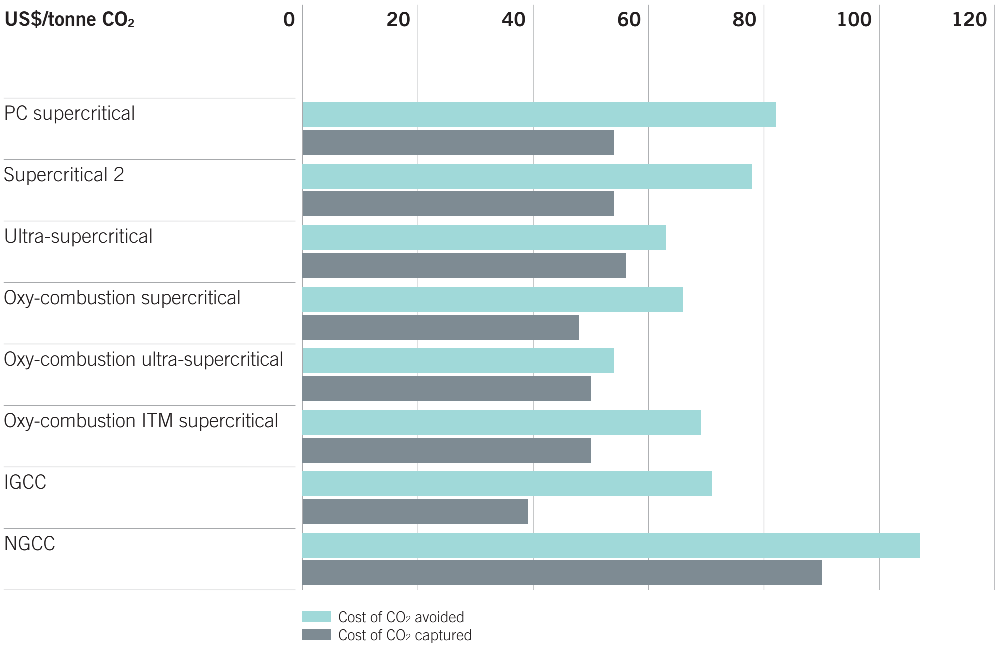


Figure 4-2 indicates varied results from the 2009 analysis, with some LCOE values increasing and some decreasing. All of the coal fired technologies show a decrease in fuel costs related to the lower coal cost used in this analysis. There is an increase in the capital contribution to the LCOE for oxy-combustion with CCS which reflects the inclusion of an additional purification process when capturing CO_2 as discussed in section 3.3. Figure 4-2 also shows the relatively small contribution that CO_2 transport has to the overall cost of CCS. Capture represents the greatest cost to CCS, and the majority of the cost increases have been due to changes in the capture system. The reduction in the length of the pipeline for the reference case has also reduced the contribution of transport cost to the overall cost of CCS to the power generation applications.

Figure 4-3 Comparison of CO_2 costs avoided and captured for power generation (FOAK)



First-of-a-kind versus Nth-of-a-kind

As introduced in Foundation Report Two in 2009, it can be expected that costs for CCS will decrease in the future as the implementation of CCS progresses along the experience curve.

There does not appear to be a great benefit with further process maturity for one CCS equipped technology over another, as indicated in Table 4-1 and Table 4-2 above. The potential cost reduction from FOAK to NOAK plants is less than 5 per cent. The reason for this small decrease is that the majority of the capital costs are associated with proven and (by and large) commercially available technologies. Therefore, decreasing the cost of risk with the new technologies does not provide the potential for future cost savings through increasing maturity.

The cost reductions presented here represent decreased risk in the existing technologies and do not consider other improvements such as implementing new technologies for capture or economies of scale savings in transportation and storage.

Introduction of emerging technologies improvements

The introduction of emerging technologies has great potential to reduce the CCS costs (Rubin 2007, EPRI 2008, US DOE 2009). Potential cost saving of emerging experienced gained and the introduction of new technologies is illustrated in Table 4-3.

Table 4-3 Reduction in LCOE after deployment of 100GW capacity

Technology	Average decrease (%)	Range (%)
PC Plant	14.4	6.2 to 21.3
Oxy-combustion	9.7	3.9 to 15.4
IGCC	17.6	7.7 to 25.8
NGCC	15.5	3.3 to 22.0

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

The ultra-supercritical, as applied to the PC-supercritical and Oxy-combustion and the ion transfer membrane (ITM) technology as applied to the oxy-combustion technology illustrate the value of the introduction of emerging technologies to reducing the costs of CCS.

Efficiency improvements

Ultra-supercritical technology provides an efficiency improvement over supercritical combustion. Ultra-supercritical power plants achieve higher efficiencies through increasing steam temperature and pressure from the boiler. For CCS, cost savings with the ultra-supercritical technology are achieved through:

- decreasing the fuel cost per MWh of generation;
- decreasing the volume of flue gas to be treated per MWh of generation; and/or
- decreasing the amount of CO_2 to be captured and compressed per MWh of generation.

Comparing the supercritical and ultra-supercritical LCOE for the PCC and oxyfuel-combustion cases in Figure 4-2, the benefits of improving generation efficiency is evident. As summarised in Table 4-4, the LCOE, including capture, transport, and storage, decrease by 6 and 9 per cent in moving from the supercritical to ultra-supercritical technologies for the PCC and oxyfuel combustion technologies, respectively. Combined with the cost decreases achieved through lessons learnt, the cost decreases approach the range of those presented by Rubin et al (2007) and are summarised in Table 4-3.

Table 4-4 Percentage change in cost parameters from supercritical to ultra-supercritical technology.

	Percentage change from supercritical to ultra-super critical			
	Post-combustion capture		Oxyfuel-combustion	
	LCOE	Cost of CO_2 captured	LCOE	Cost of CO_2 captured
Without capture	-4%	NA	NA	NA
With capture	-9%	3%	-6%	4%

Ion transfer membrane for oxyfuel combustion

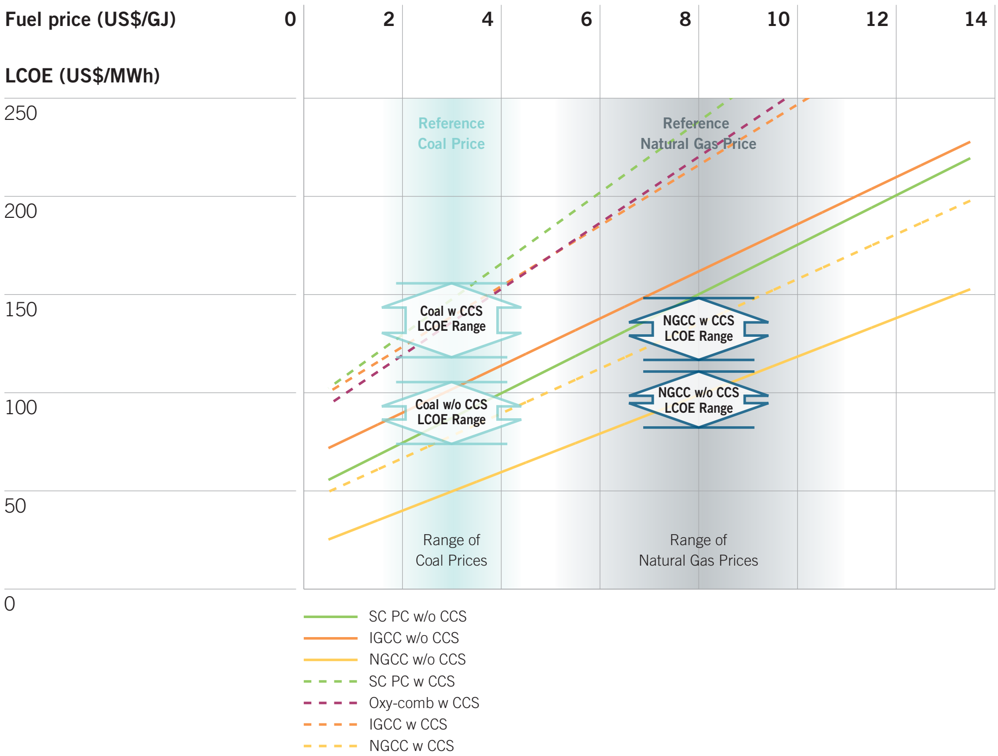
As discussed in Foundation Report Two, ITM is an emerging air separation technology that promises lower auxiliary loads and capital costs compared to cryogenic air separation. ITM presents a potential opportunity to reduce plant capital costs by 10 per cent due to a combination of reduced ASU equipment costs and decreased plant size, based on current status of development. The LCOE could also be reduced by approximately 10 per cent based on the estimations used in this model should this technology be implemented into oxy-combustion systems. This potential reduction is reported in Table 4-3 and is within the range anticipated by Rubin et al (2007).

Sensitivity study: fuel costs

As illustrated in Figure 4-2, fuel cost is a strong contributor to the LCOE. Fuel cost can vary significantly over time due to market conditions, including demand fluctuation, change in environmental regulations, speculation, natural disasters, and international disputes.

The sensitivities of the LCOE, with and without CCS, on fuel costs are illustrated in Figure 4-4. Typical fuel price ranges are included with the resulting LCOE ranges also calculated. For all coal-fired technologies, the coal price range leads to a variation in the LCOE on the order of US$10/MWh, while the natural gas price range leads to a US$30/MWh variation in the LCOE.

Figure 4-4 LCOE as a function of fuel costs



Sensitivity study: Labour costs

Labour costs for the installation and operation of a facility can vary significantly with location. The labour rates used for the base configuration are considered to be the minimum but could increase by 30 per cent within a region due to local labour conditions (that is, union labour rates or competing labour intensive projects), or up to 100 per cent in remote locations requiring labour camps. In some instances, federal government funding programs have as a condition the employment of unionised labour which can affect development costs. The sensitivity of labour to the project costs and economics in this study was the same as applied in 2009. It was investigated through applying a labour cost factor to the labour component, considering both installation and O&M labour, for each CCS component system. This factor ranged from one to two, corresponding to a labour rate increase of 0 to 100 per cent, respectively.

For a supercritical PC with CCS technology, for a fixed fuel cost, the sensitivity of the CO_2 capture installed capital costs and LCOE to the labour costs was reduced. The installed capital costs increased by 23 per cent (32 per cent in 2009), while the LCOE increased by 11 per cent (21 per cent in 2009). A similar trend would be observed for the other coal-fired technologies as they tend to be relatively labour-intensive installations.

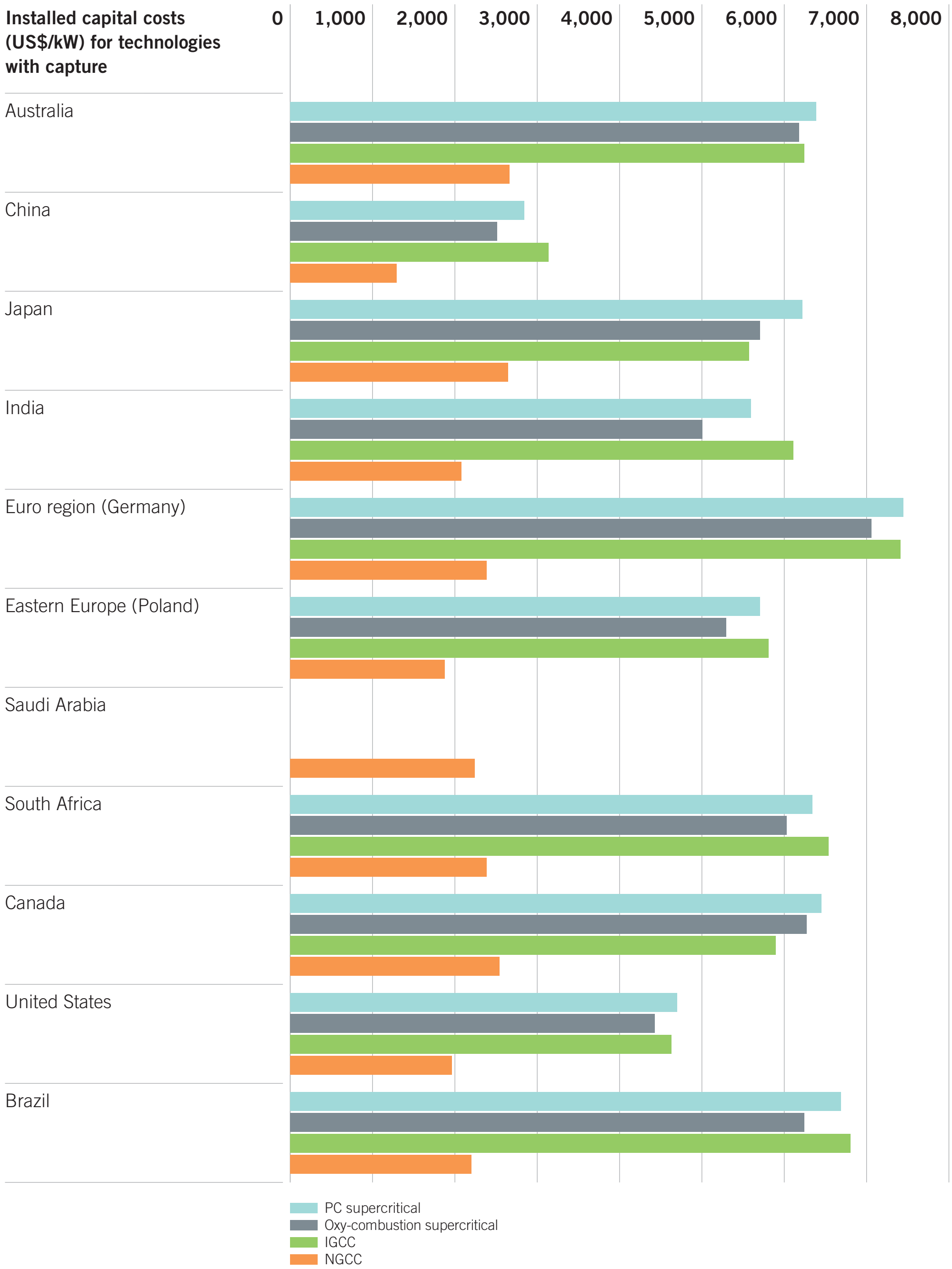
4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

Sensitivity study: Regional costs

The installed capital costs of the CO_2 capture technologies for the power generation applications are shown in Figure 4-5, while the LCOE for these applications with CCS are presented in Figure 4-6. A number of key variations since last year emerge, as listed below.

- An increase in the installed CO_2 capture equipment cost and LCOE across all technologies in India. This is due to a 30 per cent increase in equipment being imported into the country as well as India's typical coal heating value being very low, resulting in a greater capital cost.
- An increase in costs across all technologies in Eastern Europe. The increase in the reference coal price for this region has been the major contributor to this change.
- Australia has also experienced a 20 per cent increase in the technology cost which can be accounted for by the higher coal price utilised this year.
- Significant increases in costs (specifically capital costs) are seen in India and Brazil. This is partially because of a lower labour rate being used in 2009. The revision of the coal type to one with a lower heating value also leads to a higher capital cost. Finally, additional costs associated with importing capital equipment have contributed to the increase in CO_2 capture costs India and Brazil.
- Only NGCC costs are displayed for Saudi Arabia, reflecting that there are no coal-fired power generation applications in the region.

Figure 4-5 Installed CO_2 capture equipment cost as function of location

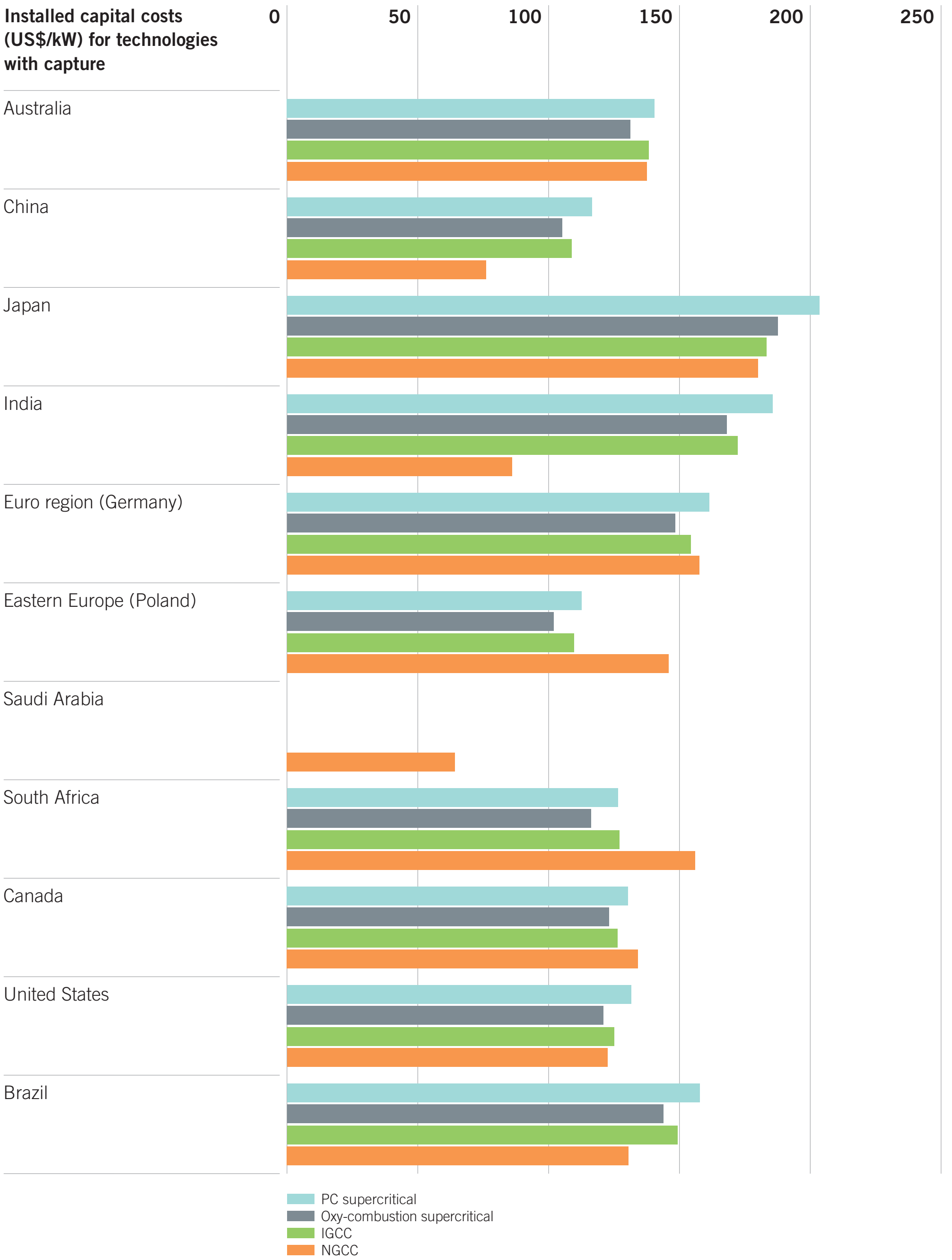


The update of the fuel costs between the regions have increased the LCOE for several of the regions including Australia, China, India and Brazil. In comparing regions, the impact of the variation in fuel costs related to the fuel source and the contract type should be remembered. In many of these regions, such as the United States, Australia, and Europe, there are different coal sources that need to be considered along with the associated variation in price. Additionally, countries may choose to source their coal from international markets in the case where it may

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

provide an economic benefit. Therefore, the cross-regional results presented in Figure 4-6 should be considered along with Figure 4-4 which illustrates the dependence of the LCOE on fuel costs.

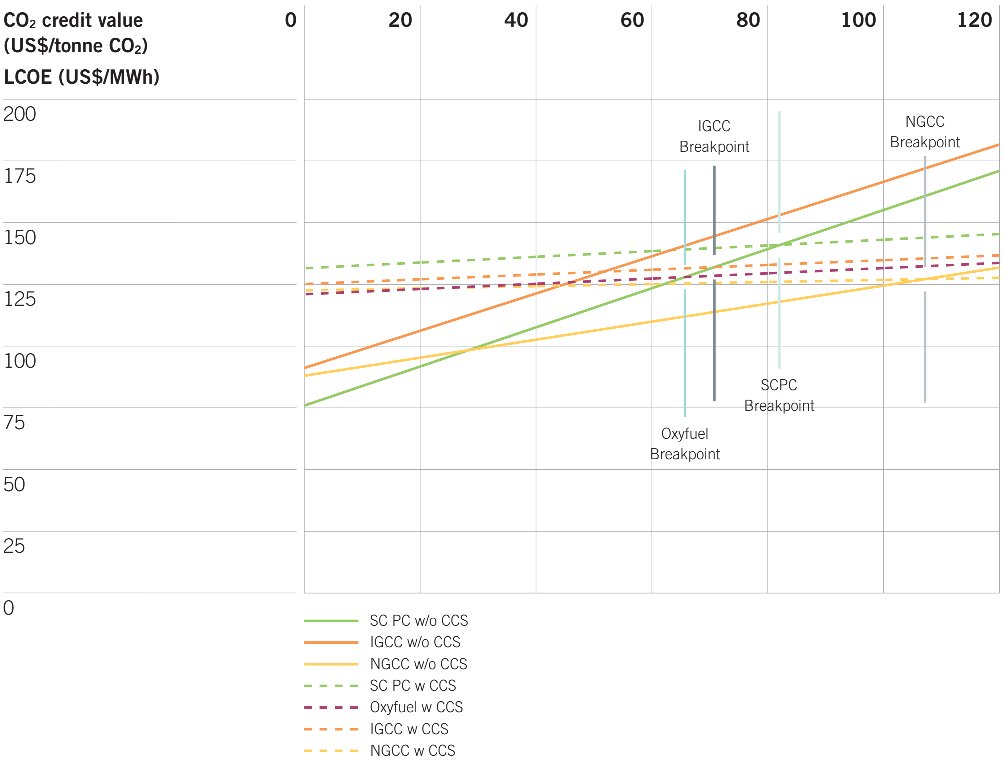
Figure 4-6 LCOE, including CCS, as a function of location



Sensitivity study: CO_2 credit value breakpoint

The CO_2 credit value breakpoint refers to the CO_2 credit value, as a $/tonne of CO_2 emitted, that drives the economics in favour of a CCS system over that without CCS. Below the breakpoint, it is more economically favourable to operate the system without CCS and for owners to pay for the emissions in the form of a tax or purchased credits. Figure 4-7 illustrates the breakpoints for the major generation and CO_2 capture technologies considered. While the oxyfuel combustion technology becomes favourable at the lowest CO_2 credit value, conversely, NGCC does not become favourable until a CO_2 credit value of greater than US$100/tonne of CO_2 is reached. This is primarily related to the lower CO_2 emission intensity of natural gas and relatively high efficiency of NGCC, as elaborated further below.

Figure 4-7 CO_2 credit value breakpoint comparison for CO_2 capture technologies.



The breakpoint for the CO_2 credit value for oxyfuel has decreased from US$60/tonne of CO_2 in 2009 to US$55/tonne, which can be attributed to the lower coal costs offsetting the additional purification step included in this study. This analysis continues to indicate that oxyfuel still has the lowest CO_2 credit value breakpoint of approximately US$55/tonne of CO_2.

The IGCC breakpoint, with respect to supercritical PC technology has decreased from US$80/tonne in 2009 to US$70/tonne of CO_2. This reflects the increase since 2009 in the LCOE and cost of CO_2 avoided and captured for IGCC with CCS.

The cost breakpoint for the supercritical technologies is approximately US$80/tonne of CO_2, an 11 per cent decrease from the 2009 breakpoint of US$90/tonne of CO_2.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

The high breakpoint for NGCC technology has remained relatively unchanged at US$112/tonne of CO_2, reflective of the lower CO_2 emission intensity of natural gas and higher cycle efficiency compared to coal-fired technologies.

Care needs to be used in assessing technologies with this breakpoint approach. While the breakpoint of a technology may be the lowest, indicating a smaller cost increase to incorporate CO_2 capture, the initial cost of the technology may be high, thus still leading to a greater LCOE.

4.1.2 Industrial applications

The FOAK and NOAK cost parameters based on the methodology and assumptions described in section 3.6 for the industrial processes are listed in Table 4-5.

Table 4-5 Incremental cost of CCS for industrial processes

	Blast furnace	Cement	Natural gas processing	Fertiliser production
FOAK				
Incremental levelised product costs	US$82/tonne steel	US$34/tonne cement	US$0.056/GJ natural gas	US$11/tonne ammonia
Cost of CO_2 avoided/captured	US$54/tonne CO_2	US$54/tonne CO_2	US$19/tonne CO_2	US$20/tonne CO_2
NOAK				
Incremental levelised product costs	US$74/tonne steel	US$31/tonne cement	US$0.056/GJ natural gas	US$11/tonne ammonia
Cost of CO_2 avoided/captured	US$49/tonne CO_2	US$49/tonne CO_2	US$19/tonne CO_2	US$20/tonne CO_2

For the industrial processes, the incremental levelised product costs and the cost of CO_2 avoided/captured have increased by a small amount consistently across all applications. For PCC of CO_2 from blast furnace steel and cement production are in the order of US$50/tonne of CO_2. These costs are inclusive of the capture and compression of the CO_2 at the capture facility and the subsequent transportation and storage costs. A reduction of approximately 10 per cent is achieved through the removal of process contingency applied to the capture technology in moving from FOAK to NOAK systems.

The cost of CO_2 avoided/captured is lower than those of PCC for industrial processes that currently include a CO_2 separation/capture process, such as in natural gas processing and fertiliser production. The costs of CO_2 avoided/captured are US$19/tonne of CO_2 and US$20/tonne of CO_2 respectively for these facilities. As discussed in 2009, the additional auxiliary load required is for the compression components only, compared to the capture and compression of the PCC case. This is also a reason for the lower CCS costs for these facilities.

Table 4-6 shows the current commodity prices and the resulting increase in commodity prices, derived from the incremental levelised cost of production. The percentage increase is strongly linked to the commodity price with lower cost commodity prices being impacted to a greater extent. For example, the commodity cost for steel has increased from US$350-500/tonne in 2009 to US$570-800/tonne in 2010. As a result, the contribution that CCS has to the overall commodity cost is reduced.

Table 4-6 Commodity cost increase from CCS implementation

	Commodity cost	CCS cost increase
Steel	US$570-800/tonne	10-14%
Cement	US$66-88/tonne	39-52%
Natural gas	US$4.97/GJ	1%
Ammonia	US$375/tonne	3%

Notes:

1. Steel and natural gas commodity costs from World Bank Commodity Price Data (Pink Sheet) average or January to July 2010.
2. Portland cement prices, dependent on contract size (Portland Cement 2009).
3. Ammonia Prices and Pricing information, mid-June 2010 prices US location. (ICIS 2010)

Table 4-7 provides the cost parameters, levelised cost of production, and cost of CO_2 avoided/captured for the industrial processes in the selected regions. The cost factors used for moving the projects are listed in Table 3-3. Among the countries listed, the CCS cost parameters vary over a range of approximately 25 per cent. The countries with lower labour costs (China, India and Brazil) and low energy costs (Saudi Arabia) have the lowest cost for implementing CCS. The costs presented here are indicative of moving the same project, including the capture system and multi-user pipeline and storage, from a reference location to other regions. In assessing actual projects and comparing costs to existing projects, the characteristics and configuration of the industrial process as well as existing and proposed transportation and infrastructure must be taken into account.

Table 4-7 CCS cost parameters for NOAK industrial processes

		Blast furnace		Cement kiln		Natural gas processing		Fertiliser production	
Region	Country	ΔLCOP ($/tonne steel)	Cost of CO_2 avoided ($/tonne CO_2)	ΔLCOP ($/tonne cement)	Cost of CO_2 avoided ($/tonne CO_2)	ΔLCOP ($/GJ natural gas)	Cost of CO_2 avoided ($/tonne CO_2)	ΔLCOP ($/tonne ammonia)	Cost of CO_2 avoided ($/tonne CO_2)
ANZ	Australia	87	57	36	57	0.060	20.4	11.3	20.9
Asia	China	54	35	22	35	0.046	15.8	8.7	16.1
Asia	Japan	96	63	40	63	0.068	23.3	13.0	24.0
India	India	69	45	29	45	0.048	16.6	9.1	16.8
Europe	Euro Area	88	57	37	57	0.064	21.7	12.1	22.3
Europe	East Europe	77	51	32	51	0.061	20.9	11.6	21.4
ME/Africa	Saudi Arabia	66	43	27	43	0.044	15.0	8.2	15.2
ME/Africa	South Africa	88	57	36	57	0.063	21.6	12.0	22.1
Americas	Canada	88	57	36	57	0.060	20.6	11.4	21.1
Americas	United States	74	49	31	49	0.056	19.3	10.7	19.7
Americas	Brazil	80	52	33	52	0.058	19.8	11.0	20.2

ΔLCOP=Incremental change in levelised cost of production.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

4.2 CO_2 transportation by pipeline

As stated in the 2009 study, the pipeline transportation of CO_2 offers potential cost savings through combining the flow of CO_2 from multiple sources into a single pipeline for delivery to a single storage site.

Following the methodology used in the 2009 study, in the reference cases the CO_2 flow through the pipelines was set to the CO_2 generated by a single facility.

Figure 4-8 illustrates the cost savings achieved through increasing the CO_2 flow through a pipeline. As illustrated in Figure 4-8, the cost to transport the CO_2 will be between US$1-2 per tonne of CO_2. Through combining three or more plants, the CO_2 flow can be increased to greater than 10Mt per year, leading to a cost of less than US$1 per tonne for CO_2 transport. The resulting impact on the LCOE is illustrated in Figure 4-9.

Figure 4-8 Transportation cost saving from increasing pipeline flow for 100km pipeline

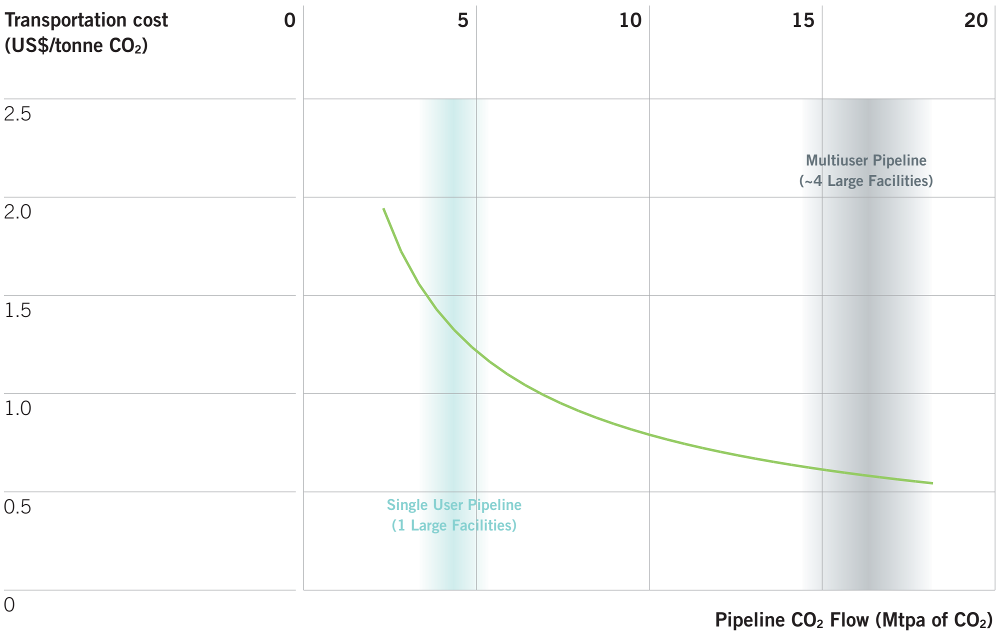
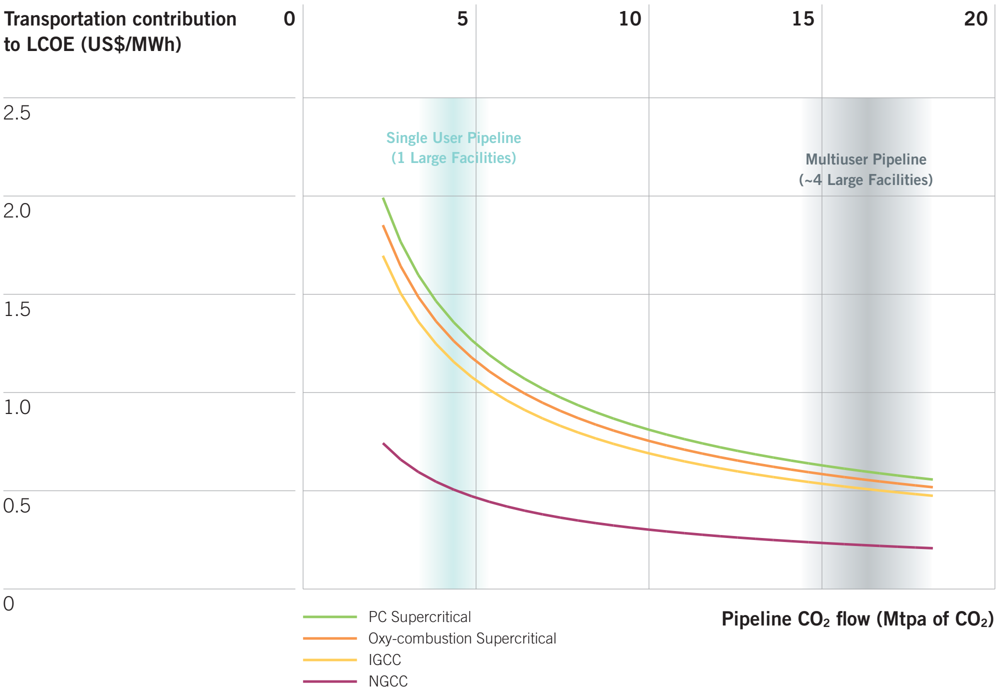


Figure 4-9 Transportation contribution to LCOE versus pipeline flow for 100km pipeline



The costs of CO_2 transport were less than those from they 2009 study as a result of the length of the pipeline being reduced from 250km to 100km.

4.3 CO_2 storage

Initial Storage Site Finding and Characterisation Costs

To illustrate the impact of this cost on the CO_2 storage cost, a sensitivity study was performed by varying the site characterisation costs over the anticipated cost range. The same cost range was used from the 2009 study (US$15 million to US$150 million) with the resulting impact on CO_2 storage cost illustrated in Figure 4-10 and the storage cost contribution to LCOE shown in Figure 4-11. The upper value of US$150 million was used as this was considered the economic threshold before proponents would abandon investigations.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

Figure 4-10 Dependence of CO_2 storage costs on initial site characterisation and identification costs

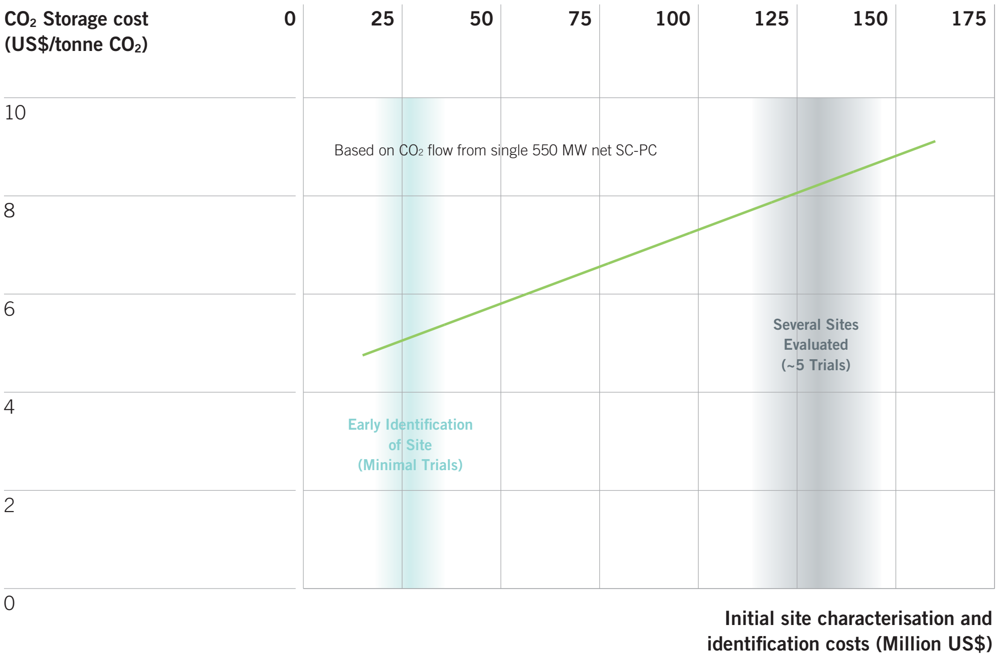
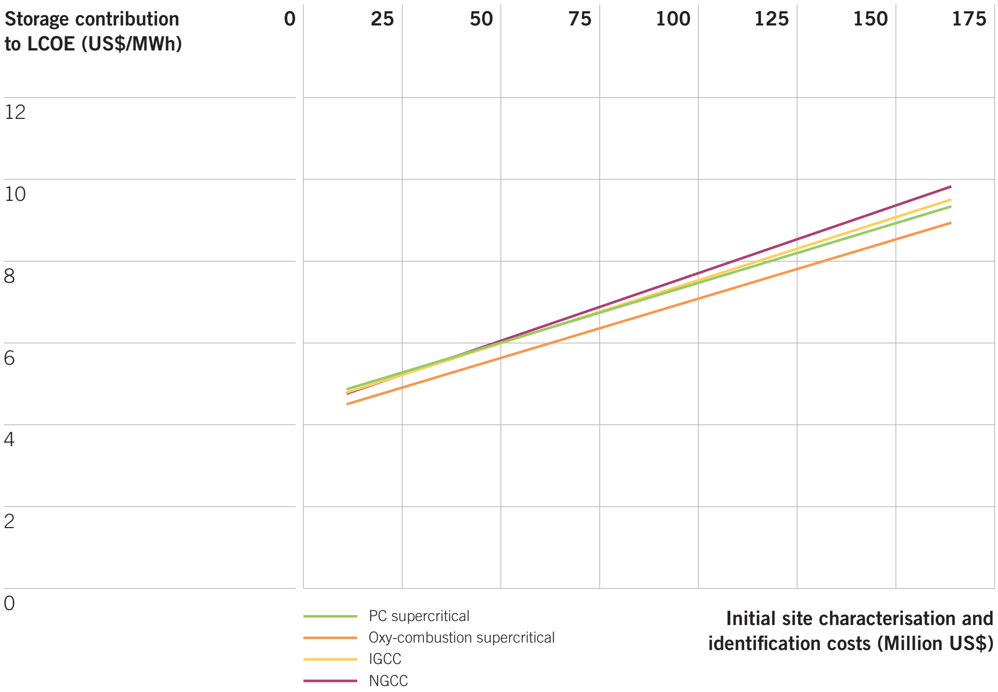


Figure 4-11 Dependence of storage contribution to LCOE on initial site characterisation and identification costs



Storage site geological characteristics

The reservoir geological properties govern the rate that the CO_2 can be injected. For reservoirs with geologic properties (low reservoir permeability thickness product) that significantly limit the injection rate, additional wells in the same area will be required to take all of the CO_2 from the pipeline. However, the number of wells, and hence maximum rate in a given area, is limited not by the performance of a single well but by pressure interference between them, such that there is a diminishing return (incremental injection rate) for additional wells. A sensitivity study for the CO_2 storage costs ($/tonne) and the LCOE ($/MWh) around the poor (absolute permeability = 150md and thickness = 5m) and the good (absolute permeability = 400md and thickness = 15m) reservoir properties are shown in Table 4-8.

In the case of the 'poor reservoir' case for NGCC, the storage cost contribution to LCOE is lower than for the other power generation applications. This can be attributed to the volumes of CO_2 from an NGCC facility being approximately half that of the others. On the other hand for the 'good reservoir' case for NGCC, the storage cost contribution to LCOE is comparable to those of the other power generation applications as the number of wells required to inject the greater volumes of CO_2 from the other applications is small.

Table 4-8 Storage cost and contribution to LCOE based on reservoir properties

Reservoir properties	Storage cost contribution to LCOE (US$/MWh)				Storage cost US$/tonne CO_2
	PC supercritical	Oxy-combustion supercritical	IGCC	NGCC	
Poor	13	13	13	9	13
Good	6	6	6	6	6

Summary of storage considerations

A number of reservoir characteristics for these conceptual case studies were assumed that allow a rapid preliminary assessment of their potential project economics. However, the reader must understand that these same assumptions remain simplifications for the purposes of these preliminary macroeconomic models. Developing an actual project will require a much deeper assessment that will require a project specific model be built once a suitable storage site has been identified and characterised.

Using these conceptual study assumptions, the overall economics show the discounted cost of storing a tonne of CO_2 is similar in both cases at approximately US$10/tonne CO_2, which shows that the storage costs under the assumptions used here could be relatively minor contributors to the overall cost of a full CCS project. However, such a statement must be read with caution that the assumption being made is that the exploration and appraisal program that must be undertaken to prove up the sites, works perfectly, and that the exploration wells can be re-used as both injection and monitoring wells. Thus there is no 'lost' exploration funds exhausted on sites that prove technically unsuitable for CO_2 storage. Likewise, should a move offshore be required, it would dramatically increase the cost of CO_2 storage and transportation over that used here.

4 RESULTS AND COMPARATIVE SENSITIVITY ANALYSIS (CONTINUED)

In reality, some key observations can be made on the cost of storing CO_2. This model only considers onshore storage. However, the authors are aware of many projects proposing to store CO_2 offshore. Storing CO_2 offshore will increase costs significantly, especially in the existing relatively tight market for offshore drilling rigs and platforms.

Water issues are also becoming apparent, not just for CCS projects but for other new hydrocarbon projects such as shale gas and coal seam methane. Thus, it is reasonable to expect that there may be more upfront (and on-going) work needed to ensure regulators are satisfied that there is little or no impact of CCS operations on water resources. This extra monitoring will increase costs.

This analysis has also only considered ‘proven’ geological storage options into saline aquifers or depleted oil and gas reservoirs, and not any potential EOR, enhanced gas recovery (EGR) or enhanced coal-bed methane recovery (ECBM) options that could provide an offsetting economic benefit of carbon capture through beneficial re-use. ECBM still has a number of technical issues needing solved prior to the implementation on large scale CCS project though progress is being made, notably in the US and beneficial re-use needs to be considered on its own merits should it prove a potential early revenue generator for CO_2 use. That said, the authors do reiterate that the sheer volumes of CO_2 being emitted from even small power stations (500MW +) places a fundamental supply and demand mismatch with many EOR projects that would be at best only able to utilise 1-2Mtpa CO_2 and indeed may not have anything like the 30 year lifespan of a power station project. This was discussed in Foundation Report Two in 2009.

As stated previously, CO_2 storage costs are site specific and the local geology will drive the costs of CO_2 storage. Injection enhancements such as deviated wells and fracturing operations may increase the injection rates, but the trade-off will need to be evaluated in the specific site context. The costs shown here are conservative. Based on currently industry trends, it is unlikely that these will decrease in the near future. Furthermore, many potential market pressures exist that are only likely to increase from this point onwards given the continued demand for oilfield services around the world.

It is important to recognise that should CO_2 storage demand increase as much as predicted, then it will place significant pressure on the supply of oilfield services competing against a mature industry (hydrocarbons). As a result, prices and price inflation could rise significantly more than that assumed in this study.

5 CONCLUSIONS

The second report as part of the Global CCS Institute's Strategic Analysis of the Global Status of CCS in 2009 (Foundation Report Two) gave a detailed analysis of the capture, transport and storage costs for power plants and a select range of industrial applications. This has been updated in 2011 to reflect updates to:

- the regional localisation estimates;
- capital cost estimates for power and select industrial CCS applications; and
- the overall economic model.

The revised results of the economic assessment of CCS technologies are summarised in Table 5-1.

The primary purpose in providing these costs is to compare the relative costs of CCS for various technologies. The costs are prepared for specific bases and when comparing to other project costs, variations are to be expected based on changes in design specification, owner's preferences and appetite for risk and how the project is financed. Great care and study is required to make these comparisons.

Table 5-1 Summary results of the economic assessment of CCS technologies

		Power generation				Industrial applications			
		PC supercritical & ultra super-critical*1	Oxyfuel combustion standard & ITM*1	IGCC	NGCC	Blast furnace steel production	Cement production	Natural gas processing	Fertiliser production
	Dimensions	US$/MWh	US$/MWh	US$/MWh	US$/MWh	US$/tonne steel	US$/tonne cement	US$/GJ natural gas	US$/tonne ammonia
Levelised cost of production	Without CCS*2	73-76	73-76*3	91	88	570-800	66-88	4.97	375
	With CCS FOAK*3	120-131	114-123	125	123	82	34	0.056	11
	With CCS NOAK*4	117-129	112-121	123	121	74	31	0.056	11
	% Increase over without CCS*5	61-76%	53-65%	37%	40%	10-14%	39-52%	1%	3%
Cost of CO_2 avoided*6 ($/tonne CO_2)	FOAK	62-81	47-59	67	107	54	54	19	20
	NOAK	57-78	44-57	63	103	49	49	19	20
Cost of CO_2 captured ($/tonne CO_2)	FOAK	53-55	42-47	39	90	54	54	19	20
	NOAK	52	41-45	38	87	49	49	19	20

Notes:

1. The ultra-supercritical and ITM technologies are currently under development and are not commercially available. These technologies represent options with the potential for increasing the process efficiency and reduce costs.
2. Without CCS cost of production for industrial process are typical market prices for the commodities.
3. Oxyfuel combustion systems are not typically configured to operate in an air fired mode. Therefore, oxyfuel combustion without CCS is not an option. The values here are the PC without CCS value to be used as a reference for calculating the cost of CO_2 avoided.
4. For industrial processes, levelised cost of production presented as cost increment above current costs.
5. Expressed with respect to current commodity prices industry industrial processes.

Key findings based on the updated economic modelling are presented in the following sections.

5 CONCLUSIONS (CONTINUED)

5.1 General observations

CO_2 capture still represents the greatest contribution to the cost of CCS, with the majority of the cost increases being due to changes in the capture system. The percentage increases in costs that the application of CCS has over non-CCS facilities have remained relatively unchanged since 2009.

Though minor changes in the costs of CCS across power generation and industrial applications have occurred, the costs of CCS still remain high. This is expected, given that it has only been 12 months since the initial Foundation Report Two, and major developments that have the potential to dramatically reduce the cost of CCS have not yet occurred or have been sufficiently tested for commercialisation.

Despite the costs of CCS being high relative to traditional power generation and industrial facilities, it is important to consider that these traditional methods currently emit large amounts of CO_2 into the atmosphere. Given the current and anticipated restrictions on facility emissions, these facilities will not be allowed to continue to operate as they have in the past.

The high costs of CCS as identified in this study should be considered with other low emission technologies to allow consideration of approaches to low emission power and industrial production. Further, if CCS is compared against the anticipated cost that may be imposed on facilities for emitting CO_2 it is likely to appear more competitive in a low carbon market.

5.2 Application of CCS to power generation

For the application of CCS in power generation in the United States, a decrease in fuel costs was seen across all of the coal fired technologies, related to the lower coal costs that emerged in 2010. The reduction in the length of the pipeline relative to the 2009 study reduced the contribution of transport cost to the overall cost of CCS to the power generation applications.

5.2.1 Levelised cost of electricity

For the reference cases, taking into account currently available technologies, the lowest LCOE was for oxyfuel combustion at US$114/MWh, in contrast to 2009 where LCOE for NGCC technologies was the lowest at US$112/MWh. Consistent with the findings in 2009, the LCOE for PC supercritical and IGCC technologies were the greatest at US$131/MWh and US$125/MWh respectively.

An update to the oxyfuel combustion process with CCS was the inclusion of an additional purification process when capturing the CO_2. This resulted in an increase in the capital contribution of oxyfuel combustion with CCS to the LCOE. The effects of the ranges in the coal and natural gas prices were variations in the LCOE of US$10/MWh and US$30/MWh respectively. This reflects the potential greater volatility of natural gas prices.

For a supercritical PC with CCS technology, for a fixed fuel cost, the sensitivity of the CO_2 capture installed capital costs and LCOE to the labour costs was reduced. The installed capital costs increased by 23 per cent (32 per cent in 2009), while the LCOE increased by 11 per cent (21 per cent in 2009). A similar trend would be observed for the other coal-fired technologies as they tend to be relatively labour-intensive installations.

5.2.2 Cost of CO_2 avoided

For both FOAK and NOAK plants, the cost of CO_2 avoided for the application of CCS across all power generation technologies decreased since 2009. There are various factors that resulted in this, including that most of the coal prices are lower than those modelled in the 2009 study, and that the CO_2 transport distance for the reference case was reduced from 250km to 100km, reducing the transport costs and its contribution to the overall cost of CCS;

5.2.3 Regional observations

In India, the installed CO_2 capture equipment cost and LCOE increased across all technologies. This was due to the revised consideration of a 30 per cent increase in equipment being imported into the country as well as India's typical coal heating value being very low, resulting in a greater capital cost.

The increase in costs for the coal fired technologies in Eastern Europe was primarily due to an increase in labor conversion factor from the reference location and switching to a low rank coal. Similarly, the capital cost in the euroregion increased related to a change to a low rank coal.

A higher coal price was utilised for Australia in this study, which resulted in a 20 per cent increase in the country's technology cost.

The costs in Brazil increased significantly, partially because of a lower labour rate being used in 2009. The revision of the coal type to one with a lower heating value also led to a higher capital cost. Further, additional costs associated with importing capital equipment contributed to the increase in CO_2 capture costs in Brazil.

Only NGCC costs were presented for Saudi Arabia, reflecting that there are no coal-fired power generation applications in the region.

5.2.4 CO_2 credit value breakpoint

The CO_2 credit value, on a $/tonne of CO_2 emitted basis that drives the economics of CCS in favour of a CCS system over that without CCS is known as the CO_2 value breakpoint. Once the breakpoint is exceeded, it becomes more economically favourable to operate the system with CCS.

The CO_2 credit value breakpoint for oxyfuel decreased from US$60/tonne of CO_2 in 2009 to US$55/tonne, which can be attributed to the lower coal costs offsetting the additional purification step included in this study. This analysis continues to indicate that oxyfuel still has the lowest CO_2 credit value breakpoint of approximately US$55/tonne of CO_2.

For IGCC, the CO_2 breakpoint with respect to supercritical PC technology PC technology has decreased from $80/tonne in 2009 to $70/tonne of CO_2. This reflects the increase since 2009 in the LCOE and cost of CO_2 avoided and captured for IGCC with CCS.

The cost breakpoint for the supercritical technologies is approximately $80/tonne of CO_2, an 11 per cent decrease from the 2009 breakpoint of $90/tonne of CO_2.

Finally, the high breakpoint for NGCC technology has remained relatively unchanged at $112/tonne of CO_2, reflective of the lower CO_2 emission intensity of natural gas and higher cycle efficiency compared to coal-fired technologies.

5 CONCLUSIONS (CONTINUED)

5.3 Application of CCS to select industrial applications

For the application of CCS on select industrial processes, the incremental levelised product costs and the cost of CO_2 avoided/captured have increased by a small amount consistently across all applications. A reduction of approximately 10 per cent is achieved through the removal of process contingency applied to the capture technology in moving from FOAK to NOAK systems.

Consistent with the findings from Foundation Report Two in 2009, the cost of CO_2 avoided/captured is lower for those industrial processes that currently include a CO_2 separation/capture process, compared to PCC from other industrial processes. Natural gas processing and fertiliser production, for example, already separate the CO_2 so additional expenditure is required for the compression, transport and storage of the CO_2 only.

The increases in the commodity costs due to CCS implementation also reflect the level of additional investment required to apply CCS to select industrial facilities. For example, for natural gas and fertiliser (ammonia) production, the commodity cost increases due to CCS are 1 and 3 per cent respectively. On the other hand, the commodity cost increases due to the application of CCS for steel and cement are 10-14 per cent and 39-52 per cent respectively.

5.4 CO_2 transport

The reduction in the length of the pipeline for the reference case has reduced the overall transport costs and the contribution of transport cost to the overall cost of CCS. The cost to transport CO_2 is estimated to be between US$1-2 per tonne of CO_2, a decrease from US$3-4 per tonne of CO_2 in 2009. This is due to the reduction of the pipeline length in the reference case from 250km in 2009 to 100km.

An opportunity to reduce the costs of CO_2 transport is in increasing the CO_2 flow through the pipeline, by combining the captured CO_2 from multiple sources through a larger pipeline to a common storage site. The implementation of a common user pipeline can result in a cost of less than US$1 per tonne for CO_2 transport.

5.5 CO_2 storage

The contribution of storage cost to the LCOE was found to range from US$6-13 per tonne of CO_2 depending on whether the 'good' or 'poorer' reservoir option was considered.

For the case of the 'poor reservoir' storage option being applied for NGCC, the storage cost contribution to LCOE us lower than for the other power generation applications. This can be attributed to the volumes of CO_2 from an NGCC facility being approximately half of that of the others. This has a lesser impact for the 'good reservoir' case as the number of wells required to inject greater volumes of CO_2 under this case do not vary significantly.

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APPENDICES

Appendix A Breakdown of overnight capital costs of PC supercritical facility

Table A-1 Cost accounts for PC boiler (1,000 x 2010 US$)

Acct No.	Item/description	Equipment cost ($)	Material cost ($)	Labour ($)	Bare erected cost ($)	Eng'g CM H.O. & Fee ($)	Contingencies		TOTAL PLANT COST	
							Process ($)	Project ($)	($)	$/kW
1	COAL & SORBENT HANDLING	22,886	5,991	13,389	42,266	3,821	0	6,913	53,001	97
2	COAL & SORBENT PREP & FEED	15,552	875	3,809	20,237	1,776	0	3,302	25,314	46
3	FEEDWATER & MISC. BOP SYSTEMS	65,385	0	29,372	94,757	8,614	0	17,049	120,420	221
4	PC BOILER									
4.1	PC Boiler & accessories	256,449	0	123,313	379,762	34,056	0	41,382	455,200	834
4.2	SCR (w/4.1)	0	0	0	0	0	0	0	0	0
4.3	Open	0	0	0	0	0	0	0	0	0
4.4-4.9	Boiler BoP (w/ID Fans)	0	0	0	0	0	0	0	0	0
	SUBTOTAL 4	**256,449**	**0**	**123,313**	**379,762**	**34,056**	**0**	**41,382**	**455,200**	**834**
5	FLUE GAS CLEANUP	121,634	0	40,039	161,673	15,293	0	17,697	194,663	357
5B	CO_2 REMOVAL & COMPRESSION	274,753	0	79,993	354,746	33,486	62,597	90,166	540,995	991
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Combustion turbine generator	N/A	0	N/A	0	0	0	0	0	0
6.2-6.9	Combustion turbine other	0	0	0	0	0	0	0	0	0
	SUBTOTAL 6	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	HRSG, DUCTING & STACK									
7.1	Heat recovery steam generator	N/A	0	N/A	0	0	0	0	0	0
7.2-7.9	Ductwork and stack	21,230	1,125	13,995	36,351	3,343	0	5,206	44,901	82
	SUBTOTAL 7	**21,230**	**1,125**	**13,995**	**36,351**	**3,343**	**0**	**5,206**	**44,901**	**82**
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & accessories	75,946	0	8,237	84,183	6,871	0	9,105	100,159	183
8.2-8.9	Turbine plant auxiliaries and steam piping	32,386	1,317	17,111	50,814	4,385	0	7,906	63,105	116
	SUBTOTAL 8	**108,332**	**1,317**	**25,348**	**134,997**	**11,256**	**0**	**17,012**	**163,264**	**299**
9	COOLING WATER SYSTEM	25,717	13,332	22,767	61,816	5,768	0	9,143	76,726	141
10	ASH/SPENT SORBENT HANDLING SYS	6,215	186	7,849	14,250	1,364	0	1,606	17,219	32
11	ACCESSORY ELECTRIC PLANT	24,495	12,167	33,539	70,201	6,277	0	9,702	86,180	158
12	INSTRUMENTATION & CONTROL	11,209	0	11,065	22,274	2,032	1,114	3,117	28,537	52
13	IMPROVEMENTS TO SITE	3,751	2,169	7,354	13,274	1,318	0	2,918	17,510	32
14	BUILDINGS & STRUCTURES	0	27,793	26,036	53,830	4,932	0	8,814	67,576	124
	TOTAL COST	**957,610**	**64,954**	**437,869**	**1,460,433**	**133,336**	**63,711**	**234,026**	**1,891,506**	**3,464**

APPENDICES (CONTINUED)

Table A-2 Cost accounts for IGCC (1,000 x 2010 US$)

Acct No.	Item/description	Equipment cost ($)	Material cost ($)	Labour ($)	Bare erected cost ($)	Eng'g CM H.O. & fee ($)	Contingencies Process ($)	Contingencies Project ($)	TOTAL PLANT COST ($)	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	15,665	2,827	11,864	30,356	2,778	0	6,627	39,761	77
2	COAL & SORBENT PREP & FEED	124,146	9,723	20,168	154,037	13,362	0	33,480	200,879	388
3	FEEDWATER & MISC. BOP SYSTEMS	10,562	8,463	9,974	28,999	2,712	0	7,275	38,987	75
4	GASIFIER & ACCESSORIES									
4.1	Gasifier, syngas cooler & auxiliaries	207,320	0	50,519	257,839	15,431	36,360	47,288	356,918	690
4.2	Syngas cooling (w/4.1)	w/4.1	0	w/4.1	0	0	0	0	0	0
4.3	ASU/oxidant compression	170,291	0	w/equip.	170,291	16,174	0	18,646	205,111	397
4.4-4.9	Other gasification equipment	30,560	11,134	17,201	58,895	5,646	0	13,703	78,244	151
	SUBTOTAL 4	**408,171**	**11,134**	**67,720**	**487,024**	**37,251**	**36,360**	**79,638**	**640,273**	**1,238**
5A	GAS CLEANUP & PIPING	96,734	5,219	79,386	181,339	17,454	26,141	45,223	270,157	522
5B	CO_2 REMOVAL & COMPRESSION	20,640	0	11,692	32,332	3,091	0	7,085	42,508	82
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Combustion turbine generator	105,200	0	6,098	111,298	10,336	11,130	13,276	146,039	282
6.2-6.9	Combustion turbine other	0	784	873	1,657	158	0	545	2,360	5
	SUBTOTAL 6	**105,200**	**784**	**6,971**	**112,955**	**10,494**	**11,130**	**13,821**	**148,400**	**287**
7	HRSG, DUCTING & STACK									
7.1	Heat recovery steam generator	42,269	0	5,244	47,513	4,085	0	5,160	56,758	110
7.2-7.9	Ductwork and stack	3,851	2,653	3,482	9,987	928	0	1,768	12,682	25
	SUBTOTAL 7	**46,120**	**2,653**	**8,726**	**57,500**	**5,013**	**0**	**6,928**	**69,440**	**134**
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & accessories	50,392	0	4,702	55,094	3,237	0	5,833	64,164	124
8.2-8.9	Turbine plant auxiliaries and steam piping	10,684	950	6,973	18,607	1,689	0	3,927	24,224	47
	SUBTOTAL 8	**61,076**	**950**	**11,675**	**73,701**	**4,926**	**0**	**9,760**	**88,388**	**171**
9	COOLING WATER SYSTEM	8,308	9,297	7,366	24,970	2,284	0	5,594	32,849	64
10	ASH/SPENT SORBENT HANDLING SYS	21,365	1,642	10,157	33,164	3,151	0	3,968	40,282	78
11	ACCESSORY ELECTRIC PLANT	27,704	9,505	25,910	63,120	5,847	0	13,090	82,057	159
12	INSTRUMENTATION & CONTROL	12,592	2,244	7,837	22,673	2,055	1,134	4,291	30,153	58
13	IMPROVEMENTS TO SITE	3,804	2,255	9,130	15,190	1,512	0	5,010	21,712	42
14	BUILDINGS & STRUCTURES	0	7,130	8,041	15,171	1,403	0	2,721	19,294	37
	TOTAL COST	**962,087**	**73,827**	**296,617**	**1,332,531**	**113,334**	**74,764**	**244,510**	**1,765,138**	**3,413**

Table A-3 Cost accounts for Oxyfuel Combustion (1,000 x 2010 US$)

Acct No.	Item/description	Equipment Cost ($)	Material Cost ($)	Labour ($)	Bare Erected Cost ($)	Eng'g CM H.O. & Fee ($)	Contingencies Process ($)	Contingencies Project ($)	TOTAL PLANT COST $(x1,000)	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	22,026	5,762	12,876	40,664	3,662	0	6,649	50,975	93
2	COAL & SORBENTPREP & FEED	14,964	843	3,665	19,472	1,702	0	3,176	24,350	44
3	FEED WATER & MISC. BOP SYSTEMS	56,548	0	25,569	82,117	7,411	0	14,472	104,001	190
4	PC BOILER/GASIFIER									
4.1	PC boiler & accessing	243,473	0	117,076	360,549	32,008	53,683	44,624	490,865	895
4.2	SCR (w/4.1)	w/4.1	w/4.1	w/4.1	w/4.1	w/4.1	w/4.1	w/4.1	w/4.1	w/4.1
4.3	Open	0	0	0	0	0	0	0	0	0
4.4-4.9	Other equipment-ASU	136,708	0	108,574	245,282	23,930	0	26,921	296,134	540
	SUBTOTAL 4	**380,181**	**0**	**225,650**	**605,831**	**55,939**	**53,683**	**71,546**	**786,999**	**1,434**
5A	GAS CLEANUP & PIPING	109,055	0	34,759	143,814	13,556	0	15,736	173,106	315
5B	CO_2REMOVAL&COMPRESSION	68,858	0	53,971	122,829	12,282	0	27,022	162,133	295
6	COMBUSTIONTURBINE/ACCESSORIES									
6.1	Combustion turbine generator	N/A	0	N/A	0	0	0	0	0	0
6.2-6.9	Combustion turbine other	0	0	0	0	0	0	0	0	0
	SUBTOTAL 6	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	HRSG, DUCTING & STACK									
7.1	Heat recovery steam generator	0	0	0	0	0	0	0	0	0
7.2-7.9	Ductwork and stack	0	0	0	0	0	0	0	0	0
	SUBTOTAL 7	**14,848**	**867**	**9,312**	**25,026**	**2,263**	**0**	**4045**	**31,335**	**57**
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & accessories	83,235	–	9,028	92,263	7,507	0	9,977	109,746	200
8.2-8.9	Turbine plant auxiliaries and steam piping	33,091	–	17,444	50,535	4,512	0	7,769	62,816	114
	SUBTOTAL 8	**116,326**	**–**	**26,472**	**142,798**	**12,019**	**–**	**17,746**	**172,563**	**314**
9	COOLING WATER SYSTEM	15,883	8,169	14,185	38,236	3,562	0	5675	47,473	87
10	ASH/SPENTSORBENT HANDLING SYS	5,992	179	7,568	13,739	1,310	0	1548	16,597	30
11	ACCESSORY ELECTRIC PLANT	30,614	16,381	44,728	91,723	8,190	0	12808	112,720	205
12	INSTRUMENTATION & CONTROL	12,263	–	12,107	24,371	2,216	0	3,270	29,857	54
13	IMPROVEMENTS TO SITE	3,732	2,157	7,315	13,204	1,307	0	2,902	17,413	32
14	BUILDINGS & STRUCTURES	–	27,172	25,477	52,649	4,799	0	8,617	66,065	120
	Total Cost	**851,291**	**61,530**	**503,652**	**1,416,472**	**130,217**	**53,683**	**195,215**	**1,795,588**	**3,272**

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