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JOHN F. KENNEDY SCHOOL OF GOVERNMENT

# Realistic Costs of Carbon Capture

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Discussion Paper 2009-08
July 2009

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## ENERGY TECHNOLOGY INNOVATION POLICY (ETIP)

The overarching objective of the Energy Technology Innovation Policy (ETIP) research group is to determine and then seek to promote adoption of effective strategies for developing and deploying cleaner and more efficient energy technologies, primarily in three of the biggest energy-consuming nations in the world: the United States, China, and India. These three countries have enormous influence on local, regional, and global environmental conditions through their energy production and consumption.

ETIP researchers seek to identify and promote strategies that these countries can pursue, separately and collaboratively, for accelerating the development and deployment of advanced energy options that can reduce conventional air pollution, minimize future greenhouse-gas emissions, reduce dependence on oil, facilitate poverty alleviation, and promote economic development. ETIP's focus on three crucial countries rather than only one not only multiplies directly our leverage on the world scale and facilitates the pursuit of cooperative efforts, but also allows for the development of new insights from comparisons and contrasts among conditions and strategies in the three cases.

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## ABSTRACT

There is a growing interest in carbon capture and storage (CCS) as a means of reducing carbon dioxide ($CO_2$) emissions. However, there are substantial uncertainties about the costs of CCS. Costs for pre-combustion capture with compression (i.e. excluding costs of transport and storage and any revenue from EOR associated with storage) are examined here for First-of-a-Kind (FOAK)[3] plant and for more mature technologies (Nth-of-a-Kind plant (NOAK))[4].

For FOAK plant using solid fuels the levelised cost of electricity on a 2008 basis is approximately 10¢/kWh higher with capture than for conventional plants (with a range of 8-12 ¢/kWh). Costs of abatement are found typically to be approximately \$150/t$CO_2$ avoided (with a range of \$120-180/t$CO_2$ avoided). For NOAK plants, the additional cost of electricity with capture is approximately 2-5¢/kWh, with costs of the range of \$35-70/t$CO_2$ avoided. Costs of abatement with carbon capture for other fuels and technologies are also estimated for NOAK plants. The costs of abatement are calculated with reference to conventional supercritical pulverized coal (SCPC) plant for both emissions and costs of electricity.

Estimates for both FOAK and NOAK are mainly based on cost data from 2008, which was at the end of a period of sustained escalation in the costs of power generation plant and other large capital projects. There are now indications of costs falling from these levels. This may reduce the costs of abatement so costs presented here may be "peak of the market" estimates.

If general cost levels return, for example, to those prevailing in 2005 to 2006 (by which time significant cost escalation had already occurred from previous levels), then costs of capture and compression for FOAK plants are expected to be \$110/t$CO_2$ avoided (with a range of \$90-135/t$CO_2$ avoided). For NOAK plants, costs are expected to be \$25-50/t$CO_2$.

**Based on these considerations a likely representative range of costs of abatement for capture (and excluding transport and storage) appears to be \$100-150/t$CO_2$ for first-of-a-kind plants and plausibly \$30-50/t$CO_2$ for nth-of-a-kind plants.**

The estimates for FOAK and NOAK costs appear to be broadly consistent in light of estimates of the potential for cost reductions with increased experience. Cost reductions are expected from increasing scale, learning in relation to individual components, and technological innova-

[3] First of a kind in this work means a first plant to be built using a particular technology.
[4] Nth of a kind assumes a large number of plants allowing for substantial learning and thus significant cost reductions

tion for improved plant integration. These elements should both reduce costs and increase net output with a given cost base. These factors are expected to reduce abatement costs by approximately 65% by 2030, although such estimates are inevitably uncertain.

The range of estimated costs for NOAK plants is within the range of plausible future carbon prices, implying that mature technology would be competitive with conventional fossil fuel plants at prevailing carbon prices.

The cost premium for generating low carbon electricity with CCS are found to be broadly similar to the cost premiums for generating low carbon electricity by other means, where mid-case estimates for cost premiums over conventional power generation at present are mainly in the range of approximately 10-25 ¢/kWh (except for onshore wind power at good sites where cost premiums are lower). These cost premiums are all expected to decline in future as technologies continue to mature.

The costs presented in this paper mostly exclude costs of transport and storage and value from permanent storage in oil fields with Enhanced Oil Recovery (EOR). Net costs to the economy of emissions abatement by CCS can be reduced or eliminated entirely by the adding the value of additional oil produced if storage of captured $CO_2$ is accompanied by EOR. EOR may thus be more prevalent for early plants than for later plants because EOR leads to a decrease in the cost of abatement for early plants. This may in turn reduce the average cost difference between FOAK and NOAK plants compared to the case when capture and compression only are considered.

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| | |
|---|---|
| AFUDC | Accumulated funds used during construction |
| Bbl/d | Barrels per day |
| BCG | Boston Consulting Group |
| BERR | The UK Government's Department for Business, Enterprise and Regulatory Reform |
| Bn | Billion |
| Btu | British thermal unit |
| Btu/kWh | British thermal unit per kilowatt hour |
| Capex | Capital cost |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage |
| CERA | Cambridge Energy Research Associates |
| CFB | Circulating fluidized bed |
| CHP | Combined heat and power |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| COE | Cost of electricity |
| CoP | ConocoPhillips |
| CST | Concentrated solar thermal |
| ¢/kWh | Cents per kilowatt-hour |
| EOR | Enhanced oil recovery |
| EPRI | Electric Power Research Institute |
| FGD | Flue gas desulfurization |
| FOAK | First-of-a-Kind |
| GE | General Electric |
| GEQ | GE Total Quench |
| GERQ | GE Radiant Quench |
| g/kWh | Gram per kilowatt-hour |
| GT | Gas Turbine |
| GW | Giga-Watt |

| | |
|---|---|
| HC | Hydrocarbons |
| HHV | Higher heating value |
| $H_2O$ | Water |
| HRSG | Heat recovery steam generator |
| $H_2S$ | Hydrogen sulphide |
| lb/MWh | Pounds per megawatt hour |
| IEA | International Energy Agency |
| IEA GHG | IEA Greenhouse Gas R&D Programme |
| IGCC | Integrated gasification combined cycle |
| kg/MWh | Kilograms per megawatt hour |
| KS-1 | Kansai-Mitsubishi proprietary solvent |
| kW | Kilowatts electric |
| kWh | Kilowatt-hour |
| LCOE | Levelised cost of electricity |
| MDEA | Methyldiethanolamine |
| MHI | Mitsubishi Heavy Industries, Ltd. |
| Mills/kWh | Mills per kilowatt-hour (one mill is equal to 0.1 ¢) |
| MIT | Massachusetts institute of technology |
| MMscf | Million standard cubic feet |
| MMscfd | Million standard cubic feet per day |
| MMt/yr | Million metric ton per year |
| MW | Megawatts electric |
| MWh | Megawatt-hour |
| NETL | National Energy Technology Laboratory |
| NGCC | Natural gas combined cycle |
| NOAK | Nth-of-a-Kind |
| NOK | Norwegian krone |
| NOx | Oxides of nitrogen |
| NPV | Net present value |
| $O_2$ | Oxygen |
| O&M | Operation and maintenance |
| Opex | Operating cost |

| | |
|---|---|
| Oxy | Oxy-combustion |
| PC | Pulverized coal |
| ppm | Parts per million |
| PCCI | Power Capital Costs Index |
| PV | Photovoltaic |
| SC | Supercritical pulverised coal plant |
| SCPC | Supercritical pulverized coal plant with post combustion carbon capture |
| SFA | SFA Pacific, Inc |
| $SO_2$ | Sulfur dioxide |
| SOx | Oxides of sulfur |
| SRU | Sulfur recovery unit |
| Sub | Subcritical pulverised coal plant |
| S&P | Standard & Poor's |
| $SO_3$ | Sulfur trioxide |
| $/tonne | Dollars per metric ton |
| $/kW-yr | Dollars per kilowatt per year |
| $/kW | Dollars per kilowatt |
| $/MMBtu | Dollars per million British thermal units |
| $/bbl | Dollars per barrel |
| TCR | Total capital requirement |
| Tonne | Metric Ton (1000 kg) |
| $tCO_2$ | Metric tons of carbon dioxide |
| Tonne/MWh | Metric Ton per megawatt-hour |
| TPC | Total plant capital cost |
| T&I | Testing and inspections |
| USC | Ultra-supercritical |

# 1. Introduction

There is a growing interest in carbon capture and storage (CCS) as a means of reducing carbon dioxide ($CO_2$) emissions. CCS is particularly appropriate for large point sources of $CO_2$ emissions, including power plants, large industrial facilities, and some natural gas production facilities (where $CO_2$ can be a significant component of the gas in the reservoir). There is particular interest in CCS for electricity generation from fossil fuels, because the power sector accounts for a large proportion of total $CO_2$ emissions (about 40% worldwide), and low-carbon electricity is likely to be increasingly in demand for decarbonising other sectors, such as residential and commercial space heating and, potentially, transport.

Most of the technologies necessary for CCS are already demonstrated. However, there are worldwide only four large CCS projects currently in operation, plus some smaller projects. Of these four large projects, three capture $CO_2$ from natural gas production (at Sleipner and Snohvit in Norway and In Salah in Algeria), and one captures $CO_2$ from synthetic natural gas manufacture (in North Dakota). No commercial scale power plants have yet been built with CCS.

The lack of experience of CCS in the power sector leads to substantial uncertainty about the costs of low-carbon power generation and thus of $CO_2$ emissions abatement using CCS. There have been many studies of likely costs, but they differ in a number of ways:

- Their basis and assumptions, for example with respect to the scale of the plant, capture rates and required rate of return on capital;
- The date when they were carried out, which can cause large differences in estimates due to increases in costs of constructing plants in recent years;
- Whether they are for an "Nth-of-a-kind" (NOAK) plants, as in the case of most studies to date, or for a First of a Kind (FOAK) plants; and,

- The detail with which they have examined plant design.

Such differences make deriving useful cost estimates from published studies problematic.

In particular, the costs of FOAK plants are markedly higher than the costs of later plants using the same type of technology. Historically, cost reductions resulting from learning and other factors have been observed to occur for a range of energy and other technologies over many decades (Wright, 1936; Boston Consulting Group, 1968; Argote and Epple, 1990; McDonald and Schrattenholzer, 2001; Taylor, Rubin et al., 2003; IEA GHG 2006). For carbon capture, cost reductions can be expected to be realized from a range of sources. Economies of scale are likely for later plants given the likely smaller scale of FOAK plants. Cost reductions are also expected to be gained from better plant system integration, including elimination of redundant or over-designed components and de-bottlenecking, and from reductions in the use of energy in the capture process, which has the potential to increase net output. Learning is also likely to lower the costs of individual plant components. Cost reductions may also come from shorter construction lead times, less conservative design assumptions due to greater experience and reductions in required rates of return for later plants due to reductions in perceived project risks. However, uncertainty attends to projections in these cost reductions.

This paper seeks to shed light on the costs of carbon capture by reviewing and comparing the available material on costs of capture for both mature technology and early plants, attempting to account for differences where possible. This paper mainly refers to US costs, for which the greatest amount of published analysis is available. It focuses mainly on the capture part of the CCS process (including compression of the $CO_2$). Capture and compression accounts for a large proportion of total CCS costs. Furthermore, transport and storage costs vary enormously with volume and distance of transport and type of sink. Indeed, as is briefly considered in Section 4, storage of $CO_2$ accompanied by Enhanced Oil Recovery (EOR) can lead to sequestration of $CO_2$, thus adding significant value rather than remaining a net cost. (In this paper when EOR is referred to it is always assumed to be associated with the storage of the injected $CO_2$). It is therefore more difficult to draw general conclusions for transport and storage, where there may be either a net cost or a net benefit, either of which may vary greatly compared with capture and compression, where costs vary less (although still significantly) between projects.

This paper is structured as follows.

- Section 2 examines the issues that arise in making cost estimates and the resulting difficulty in comparing diverse estimates.
- Section 3 evaluates and compares the results of recent cost studies of NOAK plants for a standardized set of operating and economic parameters. This comparison takes into account the issues highlighted in Section 2 to the extent allowed by information in the published data.
- Section 4 evaluates published cost estimates for proposed FOAK IGCC plants, using pre-combustion capture, including adjustments for the proposed plants' different scales and capture rates. This section also examines the effects of variations in capture rate on the costs of abatement. The effects of revenue from oil produced by $CO_2$ EOR are briefly considered.
- Section 5 compares the costs for NOAK and FOAK plants, and examines the extent to which future reductions in certain kinds of costs might account for the differences in estimates.
- Section 6 compares two case studies of post-combustion capture from a natural gas processing plant and an oil refinery.
- Section 7 compares the estimates of costs of abatement using CCS presented here with those presented by others, and with plausible carbon prices.

- Section 8 briefly compares the estimates of costs of electricity from plants with CCS with estimates of costs of other forms of low carbon power.
- Section 9 summarises conclusions.

The implications of these conclusions for policy will be addressed in a forthcoming paper.

## 2. The Difficulty of Deriving Reliable Cost Estimates

Published estimates show a wide range of costs for CCS. The range appears to be due in large part to the variability of project-specific factors, especially:

- the choice of technology and design;
- the scale of the facility;
- the type and costs of fuel used;
- the required distances, terrains and quantities involved in $CO_2$ transport;
- the scope of costs, for example whether owners' costs[5] are included and whether costs include elements such as $CO_2$ compression, transport or storage; and
- site specific factors such as topography.

Assumptions about financial parameters such as rate of return can also vary substantially.

Cost estimates may be further affected by the level of detail at which the design has been examined. Early stage engineering designs may understate costs by the omission of some necessary equipment. Even if studies are detailed, uncertainty still remains about the cost of building and running plants in practice, and about their performance.

Variations in cost estimates found in studies can also be attributed to the date of the study and accompanying uncertainty about escalation or de-escalation of costs. The costs of building

[5] Owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, legal fees, Owner's engineering, and preproduction costs.

new power plants have more than doubled since 2003 (Figure 1) (PCCI , 2008), although other indices, such as those of chemicals plant costs, show somewhat less marked volatility. This cost increase has come from rising global demand for basic construction materials, high demand for power generation equipment, and shortages of people and firms available to undertake essential engineering and construction work. There are now indications of falling prices, however, reflecting the effects of falls in commodity prices and reduced demand for new plants. Changes in commodity prices are illustrated by changes in the price of steel, which increased greatly before recently falling (Figure 2) (Metal Bulletin, 2008). Costs may continue to fall in future, but the extent and duration of any fall remains largely uncertain.

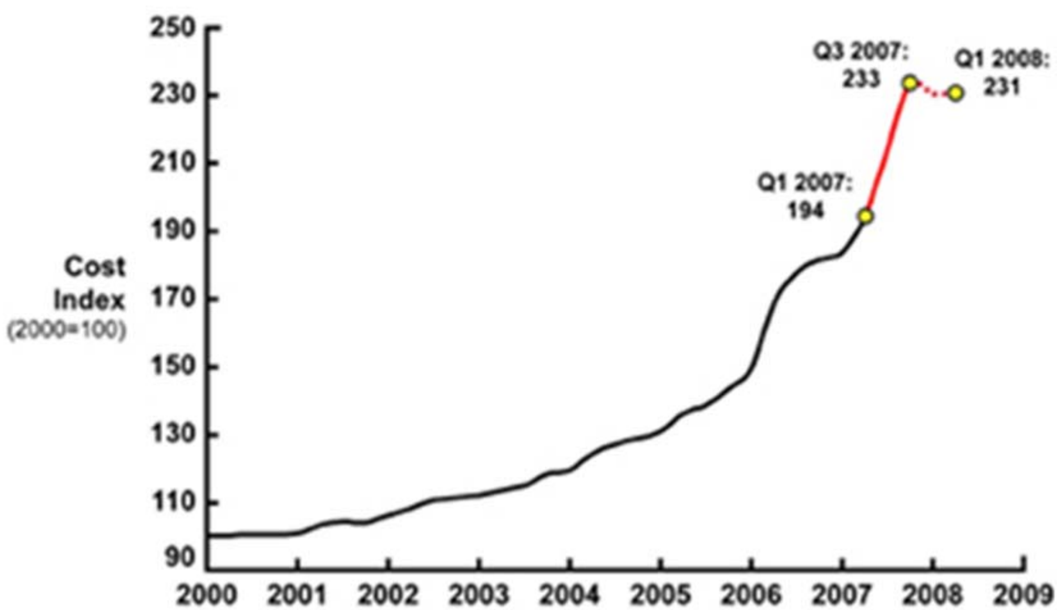


Figure 1: IHS-CERA Power Capital Costs Index (PCCI).

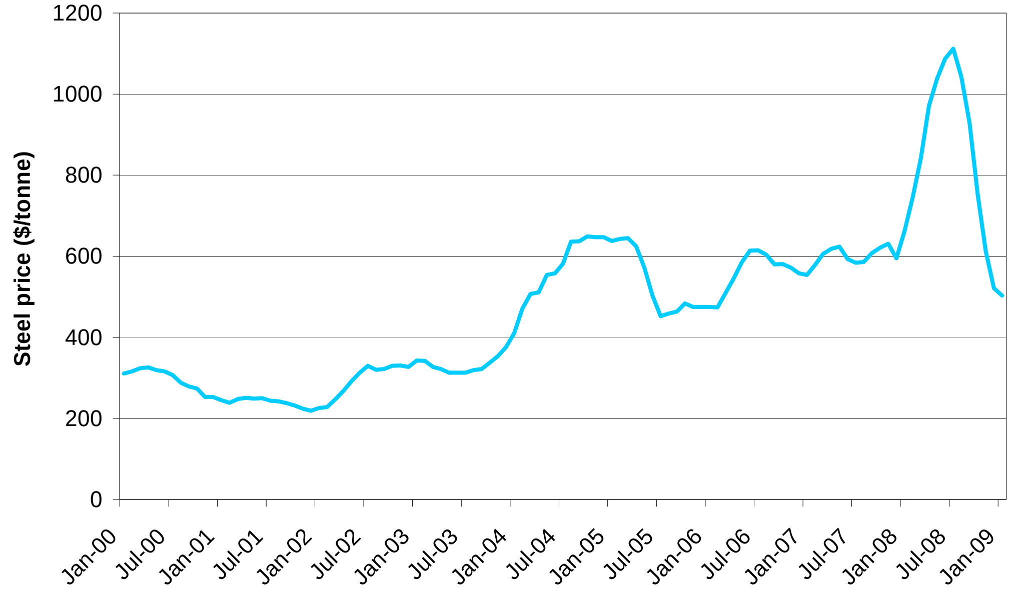


Figure 2: Steel Prices 2000-2009.

## 3. Estimates of Costs for Nth-Of-A-Kind Plants

There are several published cost estimates for NOAK plants. The technologies covered by the estimates are shown in Table 1 (abbreviations are defined in the symbols and abbreviations section). These studies, published since 2007, typically estimate the required capital cost and levelised cost of electricity (LCOE). LCOE is calculated by modelling the net present value (NPV) of the plant's cash flows, adjusting the electricity price in the model to give a zero NPV. The electricity price which, gives a zero NPV, is the LCOE. The studies that have been reviewed all deal with new plants, not retrofit plants.

The capital costs for each study were developed independently and thus exhibited considerable variation. Differences in the financial and operating assumptions that were used to calculate the LCOE also varied from study to study and further add variability to the estimated LCOE. Annexes A to C show how the assumptions and economics compare across the different studies reviewed. Other studies have been omitted if their basis appeared too inconsistent (Martelli et al., 2008; IEA GHG 2008) or they do not provide enough information to adjust to a common basis (Venkataraman et al., 2007). The IEA GHG 2008 cost update is eliminated from the analysis[6] as it does not appear to be consistent with the other analysis, for example because location and coal type differ.

Table 1: Design Studies Reviewed in Developing NOAK Economics

| STUDY | PC | | | | | IGCC | | | | NGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | SubC | SC | USC | CFB | Oxy | GEQ | GERQ | CoP | Shell | |
| MIT, 2007 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| NETL, 2007 | ✓ | ✓ | | | | | ✓ | ✓ | ✓ | ✓ |
| SFA, 2007 | | ✓ | | | ✓ | ✓ | | | | ✓ |
| Rubin et. al, 2007 | | ✓ | | | | ✓ | | | | ✓ |
| EPRI, 2007 | | ✓ | | | | ✓ | ✓ | ✓ | ✓ | ✓ |

Note: NGCC is for post-combustion capture.

### 3.1 *Standardizing the estimates*

To allow comparison of the LCOE and cost of $CO_2$ avoided[7] among these studies, estimates were re- calculated to standardize and thus place them on a common basis.

The total plant cost (TPC) costs, in $/kW, from these studies were escalated to 2008 first quarter US dollars using the IHS CERA Power Capital Costs Index (PCCI). TPC includes engineering and overhead, general facilities, balance of plant, and both process and project contingencies.

The operating and maintenance (O&M) costs were adjusted for inflation using the U.S. Department of Labor consumer price index (CPI , 2008). O&M includes fixed costs such as labor, administration and support, and some maintenance, plus variable costs for chemicals, water, and

[6] Private conversation with Shell

[7] In this paper costs are quoted per tonne of $CO_2$ avoided relative to a benchmark unless otherwise stated. Costs per tonne avoided are usually higher than costs per tonne captured due to the energy used to run the capture and compression processes and the associated production of $CO_2$ which leads to tonnes captured being greater than tonnes avoided (though this depends on the benchmark for measuring avoided tonnes).

other consumables, and waste disposal charges. Some costs include both fixed and variable components. A common set of operating and economic parameters was adopted, shown in Table 2.

Table 2: Main Financial Assumptions Applied in Cost Evaluation of NOAK Plants

| ASSUMPTION | VALUE | COMMENTS |
|---|---|---|
| Required rate of return (pre-tax, real) | 10% | The analysis in this work for the NOAK costs is based on pre-tax cash-flows and rate of return. No depreciation or tax calculation is included. Equal to assumption for FOAK plant – see section 5.6). |
| Inflation | 2% | The inflation rate is assumed to be equal for all costs and income in the project life, and is included in the nominal terms interest rate |
| Construction time | 3 to 4 years | The construction time was assumed to be 3 years for NGCC plants and 4 years for IGCC and PC plants |
| Coal price | $1.8/MMBtu | These fuel prices are on an HHV basis. The analysis is done for Illinois No. 6 bituminous coal. For CFB, lignite is assumed to be used at $1.2/MMBtu. |
| Natural gas price | $8/MMBtu[8] | On an HHV basis |
| Capacity factor (years 2-30) | 85% | Results for all fuels are presented on this basis to allow easier comparison. |
| Start up time (year 1) | 3 months | 3 month commissioning period |
| Capacity factor, remainder year 1 | 60% | Reduced load factor (60%) for remainder of year 1 |
| Plant life | 30 years | Plant may last longer, but this would lead to little variation in costs. |
| Owner costs | 10% of TPC | Excludes interest during construction. Owner costs vary widely depending on owner and site specific requirements |
| Accumulated Funds Used During Construction (AFUDC) | Varies with profile | Calculated from the expenditure construction schedule and interest rate. AFUDC is determined from TPC. The actual cash expended for construction is assumed to be spent uniformly at the middle of each year during construction. |
| Insurance and property taxes | 2% | 2% of installed costs per year and included as an operating cost |
| Transport and storage | 0 $/tonne | In most CCS systems, the cost of capture (including compression) is the largest cost component |

Normalisation is found to reduce variation in the estimates for each technology (See Annex D for detailed information).

[8] 2008 prices averaging $8/MMBtu. U.S. natural gas prices have been consistently over 5.0$/MBtu for the past three years. This sharp gas price rise has resulted in much more serious consideration of clean coal technologies as a means of diversification and fuel cost risk containment.

### *3.2 Results of the NOAK studies on a common basis*

3.2.1 LCOE with and without capture

LCOE for the PC, IGCC and NGCC technologies from the design studies, as recalculated on the standardized basis described above, are shown in Figure 3. All data points are for 90% capture. A brief description of PC, IGCC and NGCC technologies are provided in Annexes A, B and C. The length of the data bar represents the range of estimates, and the points represent the mean of the specific range. The filled circles represent the capture case and the empty circles represent the non-capture case. Where only one study was available a single point is shown.

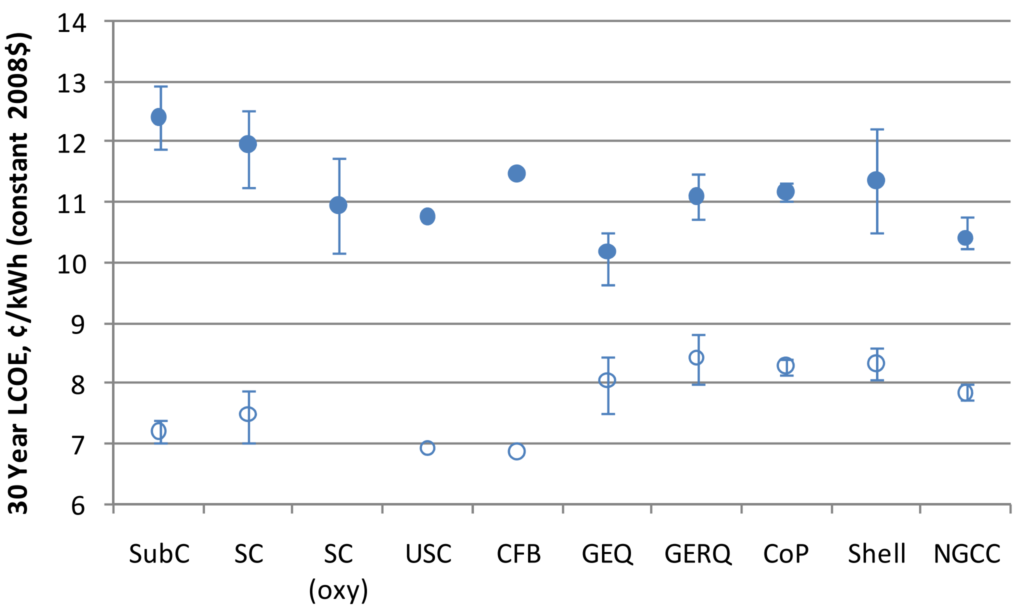


Figure 3: Levelised Cost of Electricity (LCOE) from Design Studies for Normalised Economic and Operating Parameters.

The average normalised LCOEs for plants with capture are all in the range of 10 to 13¢/kWh excluding the costs of transportation and storage. This compares to 7-9¢/kWh for plants without capture, a premium of around 2-5 ¢/kWh.

Variation of LCOEs within these ranges is likely to be well within the range of uncertainties of the estimates, especially as the ranges may include different sets of studies and different studies may refer to different states of technological development. Consequently it appears too early to draw any firm conclusion about which of the technologies might be preferred in which circumstances. However some preliminary remarks can be made from Figure 3 about relative LCOEs of plants with capture, always keeping in mind that any conclusions must be regarded as highly tentative in view of the uncertainties.

- The LCOE decreases when moving from subcritical to ultra-supercritical technology because the benefits of efficiency gains outweigh the additional capital cost (the fuel cost component decreases faster than the capital cost component increases).
- Oxyfuel combustion appears to have a relatively low LCOE in this sample. Oxy combustion is still in the demonstration phase and this early stage of development may lead to some understatement of costs at present, implying costs may be similar to or above those of other technologies in practice. At least one large scale Oxy-fuel project (planned by Saskpower) has been cancelled, reportedly due to rising costs, and replaced with a smaller project.
- The LCOE of CFB is similar to that for the PC cases. This is because cheaper lignite is the feed, and emissions control is less costly. If Illinois #6 coal were used and comparable emissions limits were applied, then the LCOE for the CFB would be significantly higher (MIT , 2007). It is also likely to benefit less in the future from economies of scale than other technologies due to the modular nature of the likely construction.

- The IGCC cost design shows a reduction in LCOE relative to PC designs. The reported Shell IGCC design appears slightly more expensive than GERQ. A $H_2O/CO$ molar ratio >3:1 is needed to ensure adequate conversion of CO and to avoid carbon formation. Shell's design requires steam to do this. The extra steam demand has a marked effect on the output of the steam turbine and the net plant output with capture and therefore on the cost of electricity. In the case of GEQ design the $H_2O/CO$ ratio is ~3/1 and the quench provides the steam required to drive the shift reaction to equilibrium. Hence there is no need to utilize steam from the cycle, leading to less impact on the net power output of the plant and on the levelised cost of electricity (EPRI_, 2007). However, there may be other configurations or developments of the Shell design that reduce the costs (Martelli et al., 2008). The three design studies focusing on Shell coal gasification process (NETL, 2006; EPRI_, 2006; IEA GHG 2008) all show HHV efficiencies, which are comparable with the commercial IGCC plant in Buggenum started in 1993. Today's best-available-technology is based on modern F-class gas turbines, such as GE 9FB or Mitsubishi 701F4 or Siemens equivalent, but this technology is not reviewed in the literature.

In summary, it should be kept in mind that most of the differences noted are within the range of the uncertainties of the estimates, so the tendencies described here may not be found in practice.

These results focus on bituminous coal-fired power plants. For such plants, IGCC technologies appear to have somewhat lower LCOE with $CO_2$ capture. Other studies have indicated that for sub-bituminous coal the cost advantage of IGCC over post combustion capture is likely to be reduced (Wheeldon et al., 2006; Stobbs and Clark, 2003) and for lignite, post-combustion capture may be the lowest cost technology (EPRI, 2006).

### 3.2.2 Costs of $CO_2$ abatement

The cost of abating $CO_2$ emissions (expressed in \$ per tonne of $CO_2$) can be calculated from the LCOE and assumptions about emissions of plant with and without capture using the standard approach described in Annex F. The cost of abatement is calculated by comparing a plant with capture to its associated reference plant (e.g. IGCC with capture vs. reference IGCC using the same technology but without capture) and by comparing all plants with capture to a common baseline supercritical pulverized coal plant. These comparisons are shown in Figure 4. They indicate a cost of abatement of approximately \$35-70/t$CO_2$.

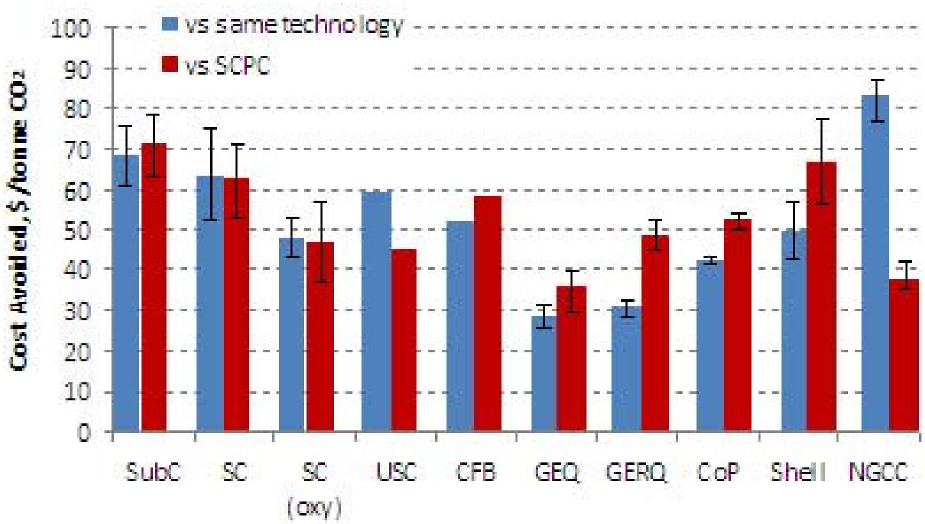


Figure 4: Cost of $CO_2$ Avoided from Design Studies for Normalised Economic and Operating Parameters for NOAK Plants.

The bars are not exactly identical in the case of SCPC since the average of the SCPC range is used in the calculation. The height of the rectangle represents the average of the specific range of the bar.

The following observations can be drawn from Figure 4:

- $CO_2$ avoided costs for IGCC plants are mainly less than for PC when a plant with capture is compared with a similar plant without capture. This is because in an IGCC plant, $CO_2$ removal is accomplished prior to combustion and at elevated pressure using physical absorption, so the incremental costs over a plant without capture are reduced.
- When the cost of an IGCC with capture is compared with the lower costs of a PC plant without capture the differences in estimated abatement costs between PC and IGCC are reduced. This reflects the higher costs of IGCC without capture relative to PC plant. Costs of abatement using NGCC are greatly reduced if compared with SCPC due to the higher emissions of SCPC plant without capture.

## 4. Estimates of Costs for First-Of-A-Kind IGCC plants

### *4.1 Comparison of published cost estimates for early IGCC plants*

There are several published cost estimates for early IGCC plants. In contrast, there is little published information on early PC projects with post-combustion capture. Post-combustion technology is relatively less well developed than pre-combustion technology, especially at scale. Only Basin Electric's Antelope Valley has published estimates. This plant is relatively small (around 120 MW) and in an unusual set of circumstances so unlikely to be representative. Consequently, we focus on IGCC for the remainder of Section 4[9], Capture from gas fueled plants is considered in the next section.

The plants considered[10] are:

- A U.S.IGCC plant with no capture initially
- A U.S.IGCC plant with 50% capture
- IGCC plants in the USA and Germany, both of which are understood to be designed for high capture rates, assumed to be 90%

Annex E shows the reported capital costs of these IGCC projects. These projects have different scales and capture rates, and so are not directly comparable. To be able to compare them more directly we have adjusted for scale and capture rates to give costs on a standardized basis of approximately 460MW net output plant with 90% capture. There will still be many differences between the projects, for example in fuel choice, technology choice, and location.

The adjustment for scale is based on bottom up modelling of plant at the level of component blocks, such as gasifiers. This modelling indicates that unit capital costs are expected to be reduced by 17.5% by doubling capacity from 250MW to 500MW, with a similar reduction when doubling from 500MW to 1000MW.

The adjustment of capture rates is based on published data on the incremental capital costs and the reduction of output, which suggest that 90% capture leads, for early IGCC plant, to approximately[11]:

[9] This reflects data availability. Post-combustion capture is expected to play an important role in global emission reduction and evidence on post-combustion costs is considered later in this paper.
[10] The IGCC projects considered are labeled generically because although some information is derived from estimates for particular plants, the adjustment made are generic and conditions at individual plants may differ significantly.
[11] There is a wide range of different estimates for these parameters, see for example Bonsu et al., (2006), White (2008), Mississippi Power (2009), Montel Powernews (2008). Values within approximately the middle of this range are taken in the light of private discussions with power engineers knowledgeable about CCS. The increase in capital costs is taken as the increase in EPC costs, with other costs such as fuel handling and project development assumed to scale pro-rata.

- a 25% increase in capital costs; and
- a 27% decrease in net power output.

Together these imply approximately a 70% increase in capital costs per kW of net power output.

Total overnight capital costs before any adjustment (shown as unadjusted costs in Figure 5) vary widely, due to the very different characteristics of the plant. However costs are similar at around $6400/kW when placed on a standardized basis (shown as adjusted costs in Figure 5). These estimates are inevitably subject to uncertainty, for example in the scope of costs included and the extent to which base data assume future cost escalation during the construction period, and we have therefore adopted a range of $6000-7000/kW as the overnight capital costs of early IGCC plants for the purposes of economic analysis. The upper end of this range includes recognition that some early plant may be smaller than the standardised size of 460MW used for the purposes of comparison.

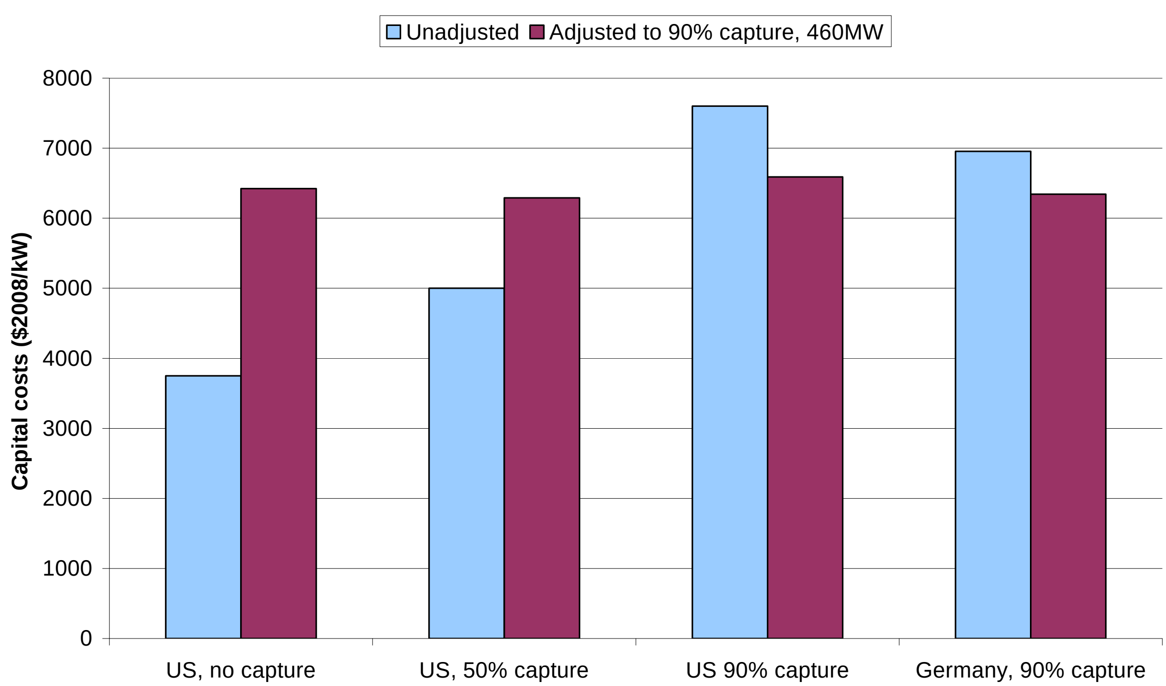


Figure 5: Costs of Early IGCC Plant Adjusted to a Common Basis of 460MW, 90% Capture

### *4.2 Levelised cost of electricity and cost of abatement for early IGCC plants*

The levelised cost of electricity is estimated from these capital costs using the assumptions shown in the table below. Other assumptions are as in Table 2, except that construction time is 5 years and plant life is 20 years. The resulting cost estimates are shown in Table 3.

Table 3: Costs of Electricity and of $CO_2$ Abatement for Early IGCC Plants

| | | | |
|---|---|---|---|
| Capital cost ($/kW) | 6000 | 6500 | 7000 |
| O&M ($/MWh) | 1.5 | 2.0 | 2.7 |
| Availability | 85% | 85% | 85% |
| Fuel ($/MMBtu) | 1.8 | 1.8 | 1.8 |
| **LCOE (¢/kWh 2008)** | **16.4** | **18.1** | **20.2** |
| **Cost $/t$CO_2$ avoided** | **121** | **149** | **179** |

The cost of abatement is estimated relative to a cost of generation of 8.0¢/kWh, reflecting costs for SCPC plant on a 2008 basis.

These estimates are mainly based on cost data from 2008, which was at the end of a period of sustained escalation in the costs of power generation and other large capital projects. There are recent indications of costs falling from these levels. If costs are reduced in this way over the longer term the costs of abatement may be reduced from these levels, perhaps greatly, and costs presented here may turn out to be “peak of the market” estimates.

It is too early for reliable indications of the magnitude of cost reductions as insufficient data is available. However, if, for example, general cost levels returned to those prevailing in 2005 or 2006, costs for FOAK plants could fall by approximately 25-30% (depending on the cost index used). This would reduce the central estimate of the cost of abatement to $110/t$CO_2$ avoided (with a range of approximately $90-135/t$CO_2$ avoided), assuming other costs to fall in line with capital costs. Costs in 2005 and 2006 had already risen significantly from costs prevailing earlier in the decade and so such a cost fall would not represent a return to the lowest prices observed in recent years.

The costs of NOAK plants would also be affected by a capex de-escalation. A similar level of capex de-escalation would reduce the NOAK costs from \$35-70/t$CO_2$ avoided to approximately \$25-50/t$CO_2$ avoided.

Based on these considerations a likely representative range of costs of abatement from CCS excluding transport and storage costs appears to be \$100-150/t$CO_2$ for FOAK plants and perhaps \$30-50/t$CO_2$ for NOAK plants.

### *4.3 Variation of cost of abatement with capture rate*

The cost of abatement and how it varies with the capture rate will depend on both the quantity of the avoided emissions and the costs of avoiding those emissions.

$$\text{Cost of abatement} = \frac{\left(LCOE_{with\,capture} - LCOE_{w/o\;capture}\right)\dfrac{\$}{MWh}}{\dfrac{\left(Q_{CO_2,\,w/o\;capture} - Q_{CO_2,\,with\;capture}\right)tonne}{MWh}}$$

Possible reference points for costs and emissions without capture include the following.

- **Case 1:** A modern conventional SCPC plant as a reference point for both emissions and costs of generation: ($LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$). This corresponds to a direct comparison of a new IGCC plant with CCS against a new conventional coal plant without capture. This is the comparison that an investor looking to build a new plant with or without capture would face and thus appears to be the most relevant measure for general analysis of abatement costs.
- **Case 2:** $LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$ are both set by an IGCC without capture. This is likely to be most relevant when an IGCC has already been built without capture and is to be retrofitted with capture.

- **Case 3:** A less efficient coal as a reference point for emissions ($Q_{CO2\ w/o\ capture}$), with the reference point for costs $LCOE_{w/o\ capture}$ being an IGCC without capture. This is relevant, for example, if a decision on capture rate is based on incentives for avoiding emissions relative to a given reference point of less efficient coal plant.
- **Case 4:** A CCGT as the reference point for both emissions and costs of generation: ($LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$).

The results of the modeling for IGCC plant are shown in Figure 6 below. Annex F discusses the mathematical modeling of the effect of capture rate on cost of abatement for early plants, which is stylised but intended to represent robustly the essential characteristics of cost trends. For the purposes of this discussion the absolute numbers are less important than the relative trends.

- **Case 1:** If the baseline is a modern efficient SCPC plant, then costs of abatement are very high at low capture rates but decrease rapidly. This is because the SCPC plant without capture is likely to have a lower LCOE than an IGCC without capture (see section 3). At low capture rates the amount of avoided emissions is relatively small and achieved at cost significantly greater than the costs of capture (because there are additional costs for IGCC without capture). Unit costs of abatement thus decrease strongly with the capture rate against a baseline of an alternative plant without capture.
- **Case 2:** The case of an IGCC with capture compared with a baseline of an IGCC without capture shows costs per tonne change little with capture rate. Depending on exact parameters they may increase with the rate of capture, stay approximately constant (case shown), or decrease slightly. As such it provides no apparent rationale for remaining at lower capture rates. Furthermore, there may be difficulties in practice in retrofitting IGCC plant without capture to achieve higher levels of capture, for example due to the need for the

turbines to burn higher hydrogen mixes. This may imply greater advantages to designing plant for higher capture levels from commissioning.

- **Case 3:** If a less efficient coal plant is chosen as the reference point for emissions avoided then the cost per tonne of abatement is reduced. This is a function of the baseline chosen, which allows a certain tranche of abatement to be credited simply by building a modern, efficient plant. The reduction in cost per tonne is greater at lower capture rates, because of this deemed amount of abatement even at zero capture rates, when no costs of capture are incurred. As such this approach does not reflect costs of abatement relative to an alternative new plant. This indicates that any payment for avoided emissions relative to a fixed baseline may need to be substantially higher at higher capture rates to encourage increases in capture rates.

If a CCGT is chosen as a reference point (not shown on Figure 6) there are no avoided emissions at capture rates below approximately 65%. At greater capture rates cost of abatement per tonne falls rapidly with capture rate, but remains higher than when plant using solid fuels is taken as the baseline.

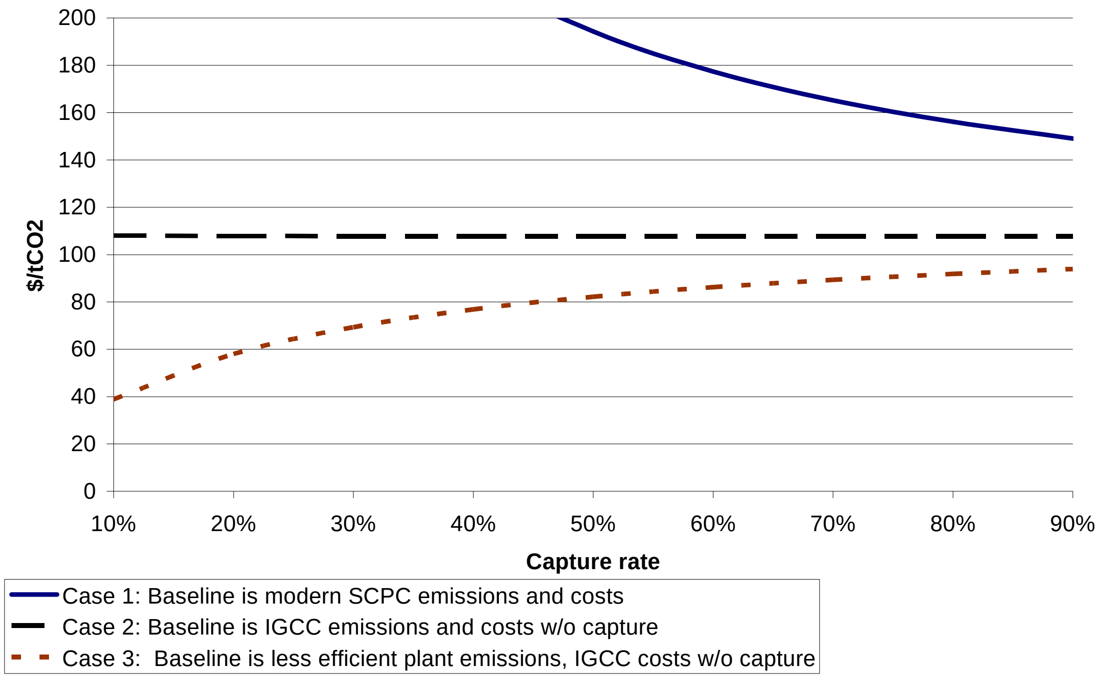


Figure 6: Comparison of Costs of Avoided Emissions

In none of the cases examined does there appear to be any minimisation of costs per tonne avoided by selecting a certain rate of partial capture around the 50% level (although absolute costs of capture are of course lower at lower capture rates simply because less $CO_2$ is being captured). Indeed for the benchmark of a conventional coal plant, the most relevant for wider analysis of abatement options, costs decrease markedly with increasing capture rates. Lower unit costs of abatement are therefore likely to result if projects are built with high capture rates. There do not seem to be any grounds based on unit cost of abatement to prefer lower capture rates for IGCC plant.

### *4.4 Value of EOR for first-of-a-kind plants*

EOR allows sequestration of $CO_2$ while providing substantial economic benefits. Where $CO_2$ is used in EOR schemes, high enough oil prices could make CCS technology competitive with conventional generation if the full net value of the additional oil is credited to the capture project. As an example, a hypothetical project (Friedman et al., 2004) proposes the following:

1. Increase oil production from10,000 bbl/d to 40,000 bbl/d, recovering an additional 150 million barrels of oil during a 20 year period.
2. Increase associated gas production from 10 MMscfd to 185 MMscfd, while $CO_2$ content in the associated gas increases from 4% to 77%.
3. Inject 122.5 MMscfd of $CO_2$ (5 Mscf/bbl) throughout the project to obtain this additional oil recovery.

This analysis is based on a 500 MWe (net power output) IGCC plant with the same assumptions for FOAK IGCC as in section 4.2. The plant produces about 10,000 tonnes of $CO_2$ per day and utilizes carbon capture. This analysis is based on the following cost data:

- The IGCC plant capital cost including capture is about $3.25 billion.
- Pipeline capital cost is $80 million (50 mile, 20-in pipeline) for transporting the recovered $CO_2$ to the oilfield. Operating cost is $0.12/Mscf $CO_2$.
- The capital cost of recycle compression for the associated gas and $CO_2$ makeup is $90 million. This example assumes a simple recycle of the associated gas because of the low flow rate of natural gas from this field.
- The $CO_2$ injection pump system has a $15 million capital cost.
- The production portion of the EOR will require material of construction upgrades because of the increasing $CO_2$ content as the flood progresses. This example assumes a $100 million cost.

- The cost of $CO_2$ injection wells varies significantly among projects, depending on the number of existing wells that can be converted to $CO_2$ injection, the maximum capacity of new injection wells, well depth, and field location. Well costs can vary from less than \$1/bbl to more than \$10/bbl of produced oil. This analysis assumes the operating costs of injection wells to be \$5/bbl.

Based on these assumptions, the project requires about \$75/bbl crude oil price to achieve a net zero cost of abatement. A higher crude oil price will increase the return on investment. Figure 7 shows the relationship of oil price and cost of $CO_2$ when EOR is included. It covers the value chain as a whole. In practice the value of the EOR is likely to be distributed between the CCS project, the reservoir owner, and the government (through taxes or royalties), and is unlikely all to accrue to the capture part of the chain project.

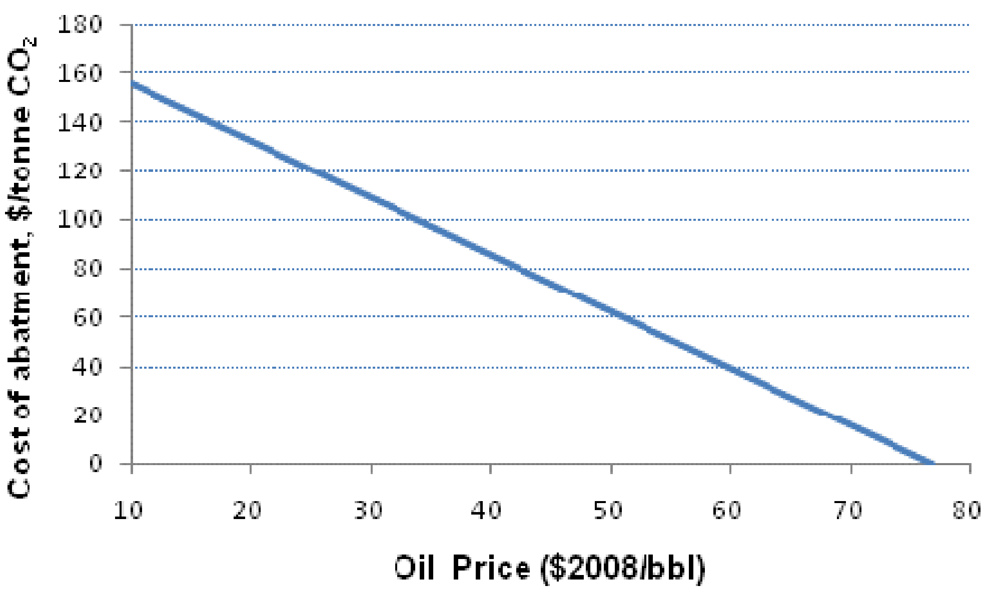


Figure 7: Value of EOR for Early IGCC Deployment

In estimating the cost of abatement with CCS we assume no effect on total carbon emissions from the oil produced. The effect of the additional oil production on emissions is complex and depends on a range of interactions. For example extra production may affect oil prices and hence gas prices in markets where these are linked, and therefore affect the competitive position of gas versus coal. The effect on emissions will also depend on the form of any emissions caps.

The simplest model is that additional conventional oil reduces the production of more expensive non-conventional resources, which are likely to be the marginal sources of oil supply in the long term, but does not significantly affect the global oil price, for example because of the shape of the supply curve for non-conventional oil or the effect of OPEC on the market. In this model global oil consumption is unaffected and, as the production of non-conventional reserves is energy intensive, there is an abatement benefit from producing additional conventional oil through EOR. Emissions would also be unaffected if a binding emissions cap covered all relevant markets.

## 5. Consistency between Estimates of Costs for Early Plant with Costs of Nth Plants

The costs of abatement for FOAK plants (excluding the benefit of EOR) is estimated as approximately \$120-\$180/t$CO_2$ on a 2008 basis. In contrast, the estimated costs for NOAK plants are much lower at \$35-70/t$CO_2$. In this section we examine if this difference can be accounted for by future cost reductions with experience.

Cost reductions for technologies are typically expressed as a learning rate, the percentage decrease in costs for each doubling of cumulative production. Learning rates have differed greatly for different energy technologies historically. In the case of IGCC with CCS it is difficult to estimate a future learning rate by the usual means because there is no historical data on CCS cost reductions, very limited deployment to date, and analogues in other sectors offer only a limited match with CCS. Reflecting these factors, learning rates have been estimated in this work by disaggregating cost reduction with experience into components for which estimates can more reliably be made than for an overall learning rate. Each of these factors is likely to influence both capex and opex, although the precise magnitude of the effect may be different.

The precise timing and magnitude of any decreases is inevitably uncertain. Among the reasons for uncertainty in the rate of achievable cost reduction is that the time taken to design and build an IGCC with CCS is several years. It will therefore be more challenging to achieve rapid learning over a number of technology cycles than with other types of technology with shorter cycle times. Consequently, the cost reductions indicated here are likely to depend on early demonstration plants being built so as to allow time for experience to be gained to allow reduce costs for subsequent generations of plant.

### *5.1 Scale*

Projects are likely to be at larger scale in future. For example, both Futuregen and Hydrogen Energy's proposed plant in California, for which a permit application has been submitted, have net output in the range 250-275MW. Other early plants may be of approximately 400-500MW scale. It is expected that eventually plants will have total output of 1-2GW, comprising more than one unit at a site, a scale typical of other baseload power plants.

The effects on costs of such scale increases can be estimated using standard bottom-up cost estimation methods. These examine the effect of scale of the unit cost of components such as turbines, where capacity increases more rapidly than costs as scale increases. The benefits of a single site for more units can also be assessed.

These estimates indicate that each doubling of scale reduces unit costs by approximately 15-20% for IGCC plants, with a central estimate of 17.5%. One such doubling is included in the estimate of future cost reduction. In practice, the typical scale of plant may more than double over the period.

### 5.2 Integration and innovation

Improved process integration, reduced redundancy and technological innovation on individual components all have the potential to contribute to cost reductions. The processes involved in an IGCC plant with CCS are complex with many steps, so there is likely to be potential for more efficient system integration as experience is gained. Furthermore, some parts of the plant are in the early stages of the technology development cycle, notably gas turbines burning hydrogen, so significant technological advances may be possible. Future advances in these areas can be hypothesised and their effects on costs estimated.

The reduction in unit costs comes from two separate effects. First, improved integration and innovation can reduce capital costs. Second, total net power output for a given capital cost can be increased as auxiliary load is reduced by better process integration and more efficient individual processes.

For the purposes of this analysis elimination of redundancy was assumed to remove the need for specific pieces of equipment in the plant, reduce the cost of the power island and reduce the auxiliary load and thus increase the net output of the plant. Together these may have the potential to reduce total costs per kW by 8-12% or more by 2030.

### 5.3 Learning on individual components

Historical data on existing installed capacity of process components such as gasifiers and learning rates exists for many parts of an IGCC plant, so future cost reductions can be extrapolated from this using standard learning curve approaches.

Learning on individual components is estimated to reduce costs by a cumulative total of 12-15% assuming no technological discontinuities (as technology step changes are captured in the integration and innovation category). This is equivalent to a learning rate of only some 3-4% for each doubling of IGCC capacity. The reason for this relatively slow learning rate is that many of the components of IGCC plant are relatively mature technologies. The addition of IGCC capacity thus represents much smaller increments of cumulative capacity for the components than it does for IGCC plants as s whole.

### *5.4 Aggregate learning rate and effect on costs*

Together the costs savings identified above yield a total cost reduction of around 40% on LCOE. This total can be taken with other assumptions to derive an overall learning rate estimate. This can then be compared with other power generation technologies. The comparison here is based on an assumption of worldwide capacity of pre-combustion capture of approximately 50-100 GW by 2030 from an initial tranche of 3GW of capacity in the next few years. This is equivalent to four or five doublings of capacity over that period.

On this basis, the sources of cost reduction identified totalling 40% cost reduction are equivalent to a total learning rate of 10-12%. This is broadly consistent with learning rates for other power generation technologies reported in the literature[12], with the exception of solar PV which, at times, has experienced a learning rate of approximately 20%[13] and nuclear energy where reliable cost data is difficult to obtain but learning rates appear to be lower, or even negative [14].

To summarize, the estimated learning rate for CCS here is based on an analysis of the disaggregated effects combined with some additional assumption about the number of doublings to provide a comparison with other technologies.

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[12] See for example studies of costs of renewables including http://www.nrel.gov/docs/fy04osti/36313.pdf, http://www.solarpaces.org/Library/docs/STPP%20Final%20Report2.pdf

[13] See e.g. (http://www.iop.org/EJ/article/1748-9326/1/1/014009/erl6_1_014009.pdf?request-id=53776976-16a0-4eea-8240-48e23b949307)

[14] See for example http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V2W-42349CF-1&_user=7018201&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000011279&_version=1&_urlVersion=0&_userid=7018201&md5=c055f88034a4ed68cb3f904e11440542

### 5.5 *Effect on LCOE*

The three types of cost reduction with experience identified together have, as noted, the potential to reduce LCOE by some 40% by 2030. This reduces the cost of abatement relative to conventional coal plants by some 65%, from approximately \$150/t$CO_2$ avoided to approximately \$50/t$CO_2$ avoided in a central case estimate based on 2008 costs. The proportional change in the cost of abatement is larger than the change in cost of electricity because the benchmark cost of generation with emissions decreases by less than the cost of generation with carbon capture. Costs of IGCC with carbon capture reduce from approximately 18¢/kWh to 11 ¢/kWh, a decrease of 40%. However costs of conventional coal plant, which forms the benchmark, may decline much more slowly because the technology is mature. For example, the cost of continued generation may decline from 8¢/kWh to 7.5 ¢/kWh. In this case the premium for plant with capture declines by much more proportionately than the power price – from 10 ¢/kWh to 3.5 ¢/kWh in this case, a decline of 65%.

The costs for abatement from mature technology (NOAK) shown here are broadly consistent with the analysis for NOAK plants reported in Section 3, the abatement cost of \$50/t$CO_2$ being well within the range of \$35-70/t$CO_2$ shown in section 3. This implies that the effects of scale, system integration, and technological learning by-doing can largely account for the difference between estimated FOAK and NOAK costs, although other factors such as those noted in the introduction to this paper may also play a role.

Consistent with this analysis some 50-100 of GW of capacity may need to be deployed worldwide to achieve costs equivalent to the NOAK costs reported in Section 3. However, the precise timing and magnitude of cost reductions remain inevitably uncertain.

### 5.6 The effects of lower risks

The financial modelling for this work has assumed the same rate of return for both FOAK and NOAK projects, in order to allow for more direct comparison of results. It is possible that a lower rate of return will be required for NOAK projects, which could lower costs of abatement. For example, there is some recognition that to recognise the risks of early plant using less mature technologies a rate of return perhaps one to two percentage points higher is appropriate[15]. The assumed rate of return (10% real pre-tax) used in this work appears roughly comparable with these precedents for early plants[16]. If a lower rate of return were required by NOAK plants, this could lead to a further reduction in costs for NOAK plant below those shown in section 4, or to costs of abatement still being at the levels shown even if some of the savings on capital or operating costs described in this section are not realised.

## 6. Comparing Costs of Capture from Industry

### 6.1 Natural gas processing plant

Saudi Aramco and Mitsubishi Heavy Industry, Ltd., (MHI) carried out a feasibility study in 2005 to determine the best option for capturing a total of 1.4 million tonnes per annum of $CO_2$ from two natural gas plants, although the capture is not from the gas streams themselves (MHI, 2005). The two gas plants were built to process associated and non-associated gas and were referred in this work as Gas Plant 1 (GP1) and Gas Plant 2 (GP2). The following five cases were selected for the study. All were found to be technically feasible except case 4.

Case -1 2,100 tonnes per day from Boilers of GP1 and 2,100 tonnes per day from GP2

Case -2 2,100 tonnes per day from Boilers of GP1 and 2,100 tonnes per day from Gas

[15] E.g. Virginia HB3068, SB11416, California resolution E4182.
[16] Depending on tax rate, assumed gearing and other factors.

Turbines of GP1

Case -3 4,200 tonnes per day from Gas Turbines of GP1

Case -4 4,200 tonnes per day from Thermal Oxidizers of GP1

Case -5 4,200 tonnes per day from Acid Gas of GP1

Capex and costs of $CO_2$ capture per tonne are summarized in Table 4 for each case. Capex consists of the initial investment cost of capture, the cost of compression and the cost of the auxiliary utilities. The technology chosen for post-combustion $CO_2$ capture from flue gas was the MHI's proprietary KM-CDR Process (Kansai-Mitsubishi Carbon Dioxide Recovery Process). Annex G contains additional details of the five cases.

Case 5, which is $CO_2$ recovery from acid gas, is the lowest in cost among all the cases studied. Acid gas enrichment was assumed to be used to recover $CO_2$ from the acid gas stream, with a 50 wt% MDEA solution to treat the acid gas.

Table 4: Comparison of Capex and Costs of $CO_2$ (in $ 2005)

| | $CO_2$ Capture Scenario | $CO_2$ Delivery Cost $/tonne | CAPEX Million US $ |
|---|---|---|---|
| Case 1 | Boilers (GP1 & GP2) | 22.0 | 160.7 |
| Case 2 | Boilers & GT GP1 | 26.2 | 153.3 |
| Case 3 | GT GP1 | 32.2 | 172.4 |
| Case 4 | Thermal Oxidizers GP1 | 28.8 | 169.8 |
| Case 5 | Acid Gas GP1 | 16.0 | 124.0 |

Note: The $CO_2$ delivery cost is reported as $ per tonne of $CO_2$ "captured".

## *6.2 Oil refinery*

One recent study (StatoilHydro, 2008) for the carbon capture facility at the Mongstad oil refinery near Bergen in Norway has shown that post-combustion $CO_2$ capture is technically feasible, but the costs are much larger than indicated by the Aramco study described above.

The Mongstad project will be developed in two phases to reduce technical and financial risk. Phase 1 includes capturing at least 80,000 tonnes of $CO_2$ using chilled ammonia and 20,000 tonnes of $CO_2$ with improved amine technology. The test facility is due for completion by 2009-2010, and will be 12–18 months in test. The goal of the test facility is to develop the most cost effective method to capture $CO_2$ from flue gases using post-combustion capture.

Phase 2 involves full-scale $CO_2$ capture from both the combined heat and power plant (CHP) station and the catalytic cracking plant. These two sources will amount to approximately 80% of the refinery's $CO_2$ emissions when the combined heat and power plant is in full operation in 2010. The project will capture approximately 1.2 million tonnes of carbon dioxide per year from the combined heat and power plant, and approximately 0.8 million tonnes per year from the cracking plant.

StatoilHydro has estimated the total capital costs for both capture facilities and their joint systems to be around NOK 25 billion (US$3.5 billion) with -30%/+40 %uncertainty. Fifty percent of the capex relates to the capture facility for CHP, 20% to the capture facility for the cracking plant, and 30% to joint systems for both capture sources.

In addition to the capital costs, StatoilHydro estimated that the annual operating expenses for the two capture facilities to be NOK 1.0 billion to 1.7 billion per year. On this basis, the costs of capture per tonne of $CO_2$ were estimated to be NOK 1,300-1,800 (2008 US$ 185-255) at a 7% rate of return.

### *6.3 Comparison with natural gas plant capture*

Table 5 looks at some key areas for comparison between the two capture projects at Mongstad and Saudi Aramco. The factors that might explain the very large difference in the costs between the two projects can be summarised as follows.

- Technology choice (MHI vs. chilled ammonia).

- The cost estimation for the two projects were in the early stage and therefore uncertainty is as high as -30%/+40 %.
- In the Middle East, the operating and labor costs are much lower than in Europe.
- Project definition and project development phases were not included in the Aramco estimates.

Table 5: Comparison between $CO_2$ Capture at a Natural Gas Processing Plant and an Oil Refinery

| | Saudi Aramco Capture Project | | Mongstad Refinery Capture Project | |
|---|---|---|---|---|
| $CO_2$ source | Thermal Oxidizer | Gas turbine | Cat Cracker | CHP |
| Flue gas | SOx and HC | - | catalyst particles, $SO_2$ and NOx | - |
| Fuel | - | Natural gas | - | Natural gas |
| Capital Costs | \$0.191 bn | \$0.194 bn | \$0.7 bn | \$1.75 bn |
| Operating Costs (1/yr) | US\$ 0.025 bn | US\$ 0.029 bn | US\$ 0.15-0.25 bn | US\$ 0.15-0.25 bn |
| Pretreatment Costs | High | No | High | No |
| Capture technology | MHI KS-1 | MHI KS-1 | Chilled ammonia/amine | Chilled ammonia/amine |
| Technical Challenge | Yes | No | Yes | No |
| Commercial Experience | Mature | Mature | Still considered new technology | Still considered new technology |
| $CO_2$ Captured | 1.3 MMt/yr | 1.3 MMt/yr | 0.8 MMt/yr | 1.2 MMt/yr |
| Cost of Capture | US\$ 32/t$CO_2$ | US\$ 36/t$CO_2$ | US\$185-255/ t$CO_2$ | US\$185-255/ t$CO_2$ |

Note: the cost of the joint systems of the two capture plants at the Mongstad project is not included in the capital costs in the table

- The uncertainty about the cost level is also due to the uncertainty relating to the market conditions for materials, equipment and personnel at the time at which the investment decision is made and during the implementation period. The Mongstad project estimates were made in 2008. However, in the case of Saudi Aramco, the estimates were made in 2005 in a period where industrial prices were more stable and lower.

However, the difference between the two estimates is large and may not be entirely accounted for by these factors alone. For example, the Aramco study used an early stage estimate provided by MHI for a project in Saudi Arabia. As such, it may not represent realisable full project costs, and may not be applicable to circumstances in Europe or the USA.

### *6.4 Comparison between pre- and post-combustion capture from a gas plant*

The expected capital cost reported for the Masdar/Hydrogen Energy 400MW pre-combustion plant in Abu Dhabi is $2 billion[17], 43% less than the capital costs estimated by Statoil for Mongstad. However the amount of $CO_2$ captured is only 15% less. The Abu Dhabi project costs include the power plant, which is excluded from the Mongstad costs. The Abu Dhabi costs exclude $CO_2$ transportation and storage. There is expected to be revenue to the project from the sale of $CO_2$ due to its value for EOR.

## 7. Comparison with Other Recent Estimates of the Costs Abatement with CCS and with the Carbon Price

### *7.1 Comparison with other estimates of the cost of CCS*

Other estimates of the cost of abatement using CCS technologies have been published recently by industry participants and observers. These are summarised in Table 6. The data are taken from a range of sources, including press reports. The basis of the costs is not always stated but most appear to include transport and storage costs.

[17] www.hydrogenenergy.com

Table 6: Estimates of Costs of CCS (\$2008/t$CO_2$ avoided)

| **Estimate Source** | **Costs now** | **Future costs (2030)** |
|---|---|---|
| Boston Consulting Group (2008)[18] | 70 | 45 |
| McKinsey (2008)[19] | 80-115 | 40-60 |
| S&P (2007)[20] | - | 40-80 |
| BERR (2006)[21] | - | 40 |
| Shell (2008)[22] | 130 | 65 or below |
| Chevron (2007)[23] | Significantly greater than 100 | n/a |
| Vattenfall (2007)[24] | 45 | 25-45 |
| **This work (excluding transport and storage)** | **120-180 on a 2008 basis**<br>**90–135 with capex de-escalation** | **35-70 on a 2008 basis**<br>**25-50 with capex de-escalation** |

Estimates rounded to nearest \$5. Some sources do not state basis of estimate and are assumed to be \$2008.

The following conclusions were drawn from the comparison:

- The costs for FOAK plant quoted here are above those quoted by others, although the bottom of the range of costs reported here for FOAK plants is broadly in line with the higher of the estimates from other parties.
- The costs for NOAK plants shown in this work are in line with other estimates. The case with capex de-escalation appears to fall below other estimates, but if transport and storage costs were included, the estimate in this work would be likely to fall in line with the other estimates, based on inspection of estimates for typical transport and storage costs in the literature.

[18] http://www.bcg.com/impact_expertise/publications/files/Carbon_Capture_and_Storage_Jun_2008.pdf
[19] €60-90/t$CO_2$ for typical early demonstration project, €30-45/t$CO_2$ by 2030, An exchange rate of 1.3\$/€ is assumed. http://www.mckinsey.com/clientservice/ccsi/pdf/CCS_Assessing_the_Economics.pdf
[20] http://www2.standardandpoors.com/spf/pdf/events/PwrGeneration.pdf
[21] http://www.berr.gov.uk/files/file42874.pdf
[22] Timesonline. 50- 100 Euros, with earlier project closer to the top of the range. An exchange rate of 1.3\$/€ is assumed.
[23] Point Carbon 13.09.07
[24] http://www.vattenfall.com/www/ccc/ccc/569512nextx/574152abate/574200power/574251abate/index.jsp

### *7.2 Comparison with carbon price projections*

The range of estimated costs for later NOAK plants of \$35-70/t$CO_2$ avoided is within the range of predicted future carbon prices if an illustrative \$20/t$CO_2$ is added to allow for the costs of transport and storage. For example a mid-case MIT projection shows a carbon price of \$78/t$CO_2$ avoided in 2030[25] (in real terms \$2007). This implies that mature CCS technology would be competitive with conventional fossil plants at prevailing carbon prices.

## 8. Comparison with the Costs of other Low Carbon Generation

It is beyond the scope of this paper to carry out a detailed review of the relative costs of different forms of low carbon generation. Such costs vary widely, in particular with site characteristics. However it is useful in the context of this paper to briefly consider some benchmarks with which the cost of generation using CCS can be compared.

LCOEs estimated on a common basis for different types of low carbon generation and for conventional fossil fuel generation are shown in Figure 8. Ranges are shown to recognise the wide variations that are present, and even then individual project costs may lie outside the ranges shown.

[25] Mid-case projection taken from "Assessment of U.S. Cap-and-Trade Proposals", by Paltsev et al, MIT 2007

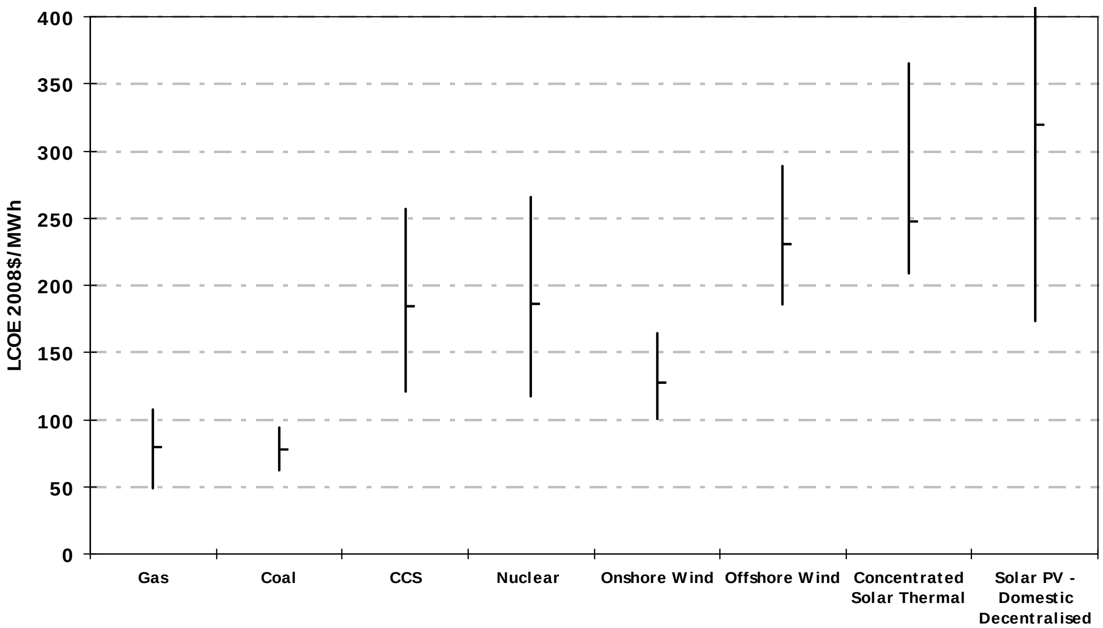


Figure 8: Relative Costs of Low Carbon Electricity Generation. Source: Estimates by Hydrogen Energy Based on a Return of 10% (Nominal Post-Tax).

The costs shown exclude:

- a carbon price;
- transmission and firming costs for renewables (and the benefits of avoided transmission and distribution costs for decentralised solar PV);
- the benefit of existing support, such as tax breaks.

The range for CCS includes allowances for transport and storage costs or some EOR benefits. Costs are higher for all technologies than those sometimes quoted. The reasons for this include:

- the timing of the cost estimates as being in 2008, following escalation in capital costs,
- exclusion of existing support, which is often netted off before quoting costs; and

- inclusion of the full costs of a project, including for example owners' costs and in the case of nuclear, likely out-turn costs when the plant is completed rather than initial estimates that are subject to increase as projects progress.

The estimates indicate that onshore wind at a good site is the lowest cost form of low carbon electricity generation (excluding intermittency costs). CCS costs are broadly comparable with those of nuclear plants and offshore wind. The top end of the CCS cost range is comparable with the costs of Concentrated Solar Thermal (CST), but with a likely cost below that of solar PV.

This pattern of costs is expected to change in future as technology costs decline at different rates, reflecting current differences in maturity (as measured by installed capacity). Costs of less mature technologies such as solar and CCS may fall more rapidly than those of more mature technologies such as nuclear, and to a lesser extent, wind. A scenario for costs in 2030 is presented in Figure 9. This scenario assumes substantial amounts of all of the low-carbon technologies shown being deployed by that date. It shows most low carbon technologies converging to a cost of $150/MWh ($2008), with onshore wind being the lowest cost.

Costs of avoided emissions are somewhat lower for other technologies than those for CCS plants at the same LCOE because there are some residual emissions from plant with CCS. However costs per tonne of $CO_2$ avoided relative to a conventional coal plant show approximately the same general pattern. Costs of abatement may also need to take account of lifecycle emissions, especially where the emissions from some inputs are outside any carbon pricing regime.

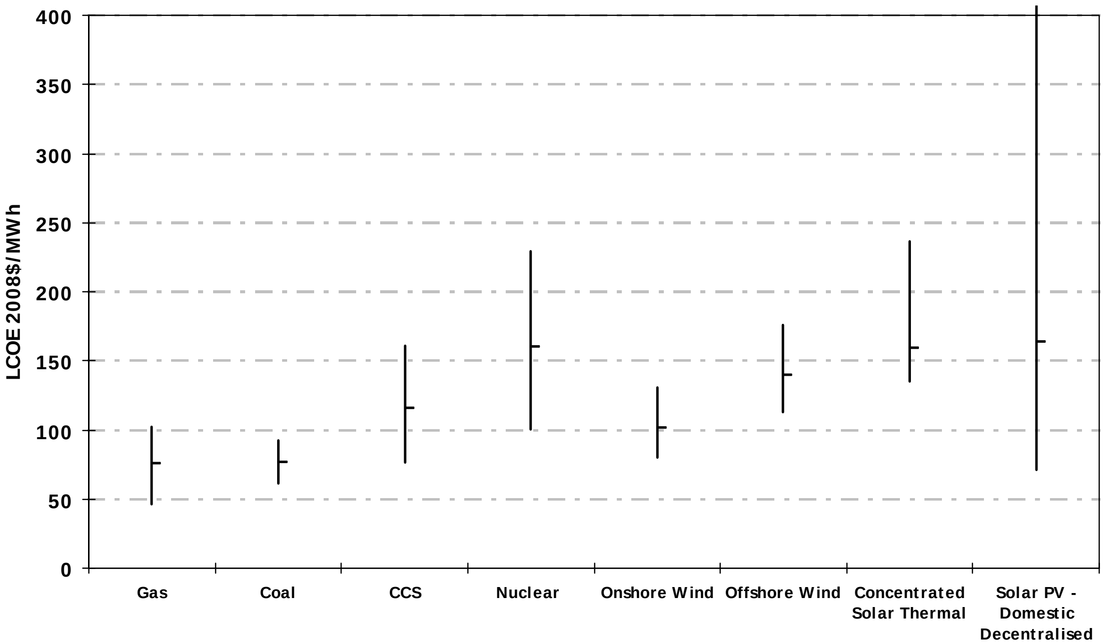


Figure 9: Cost Scenarios for 2030

## 9. Conclusions

The main conclusions from this work are as follows.

1. The costs of carbon abatement on a 2008 basis for FOAK IGCC plants are expected to be approximately \$150/t$CO_2$ avoided (with a range \$120-180/t$CO_2$ avoided), excluding transport and storage costs and revenue from EOR.
2. 2008 may have represented a peak in costs for capital-intensive projects. If capital costs de-escalate, as appears to be happening, then these costs may decline. if general cost levels were to return to those prevailing in 2005 to 2006, for example, the costs of abatement for FOAK plants would fall by perhaps 25-30% to a central estimate of some \$110/t$CO_2$ avoided (with a range of \$90-135/t$CO_2$ avoided).
3. Consequently, the realistic costs of FOAK plant seem likely to be in the range of approximately \$100-150/t$CO_2$.

4. Based on data from Statoil, the cost of post-combustion capture appears likely to be above the top end of the range. Other work by Saudi Aramco indicates potential for lower costs for post-combustion capture. Pre-combustion capture from natural-gas fueled plant may offer lower costs of abatement if the same baseline for emissions is applied as for solid-fueled plant and if gas prices are low.
5. The costs of subsequent solid-fueled plant (again excluding transport and storage) are expected to be \$35-70/t$CO_2$ on a 2008 basis, reducing to \$25-50/t$CO_2$ allowing for capex de-escalation. This estimate is consistent both with published studies of the costs of NOAK plants and estimates based on modelling the potential reductions in costs from costs of FOAK plant due to improvements in scale, plant integration and technology development.
6. The FOAK estimates are higher than many published estimates. This appears to represent a combination of previous estimates preceding recent capital cost inflation, greater knowledge of project costs following this more detailed study, and the additional costs of FOAK plants compared with the NOAK costs quoted in any published estimates.
7. The value of EOR can reduce the net cost of CCS to the economy to zero as oil prices approach approximately \$75/bbl for FOAK plants if the full net value of the EOR accrues to the project.
8. Costs of abatement vary with capture rates in ways that depend strongly on the baselines chosen for emissions and costs. Costs of abatement decrease with increasing capture rates if the baseline is the costs and emissions of a modern SCPC plant.
9. Costs of generating low carbon power using other technologies appear similar to or above the costs of generation from IGCC plants with CCS, except for onshore wind

plants, which have lower costs when located at favourable sites (excluding transmission and intermittency costs).

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## Annex A: Summary of PC Design Studies — As Reported

| STUDY | MIT | MIT | MIT | MIT | MIT | Rubin | NETL | NETL | EPRI | SFA | SFA |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Technology[b] | SubC | SC | OXY | USC | CFB | SC | SubC | SC | SC | SC | OXY |
| Cost year basis | 2005 | 2005 | 2005 | 2005 | 2005 | 2005 | 2006 | 2006 | 2006 | 2006 | 2006 |
| **Without Capture** | | | | | | | | | | | |
| Net Power (MW) | 500 | 500 | | 500 | 500 | 528 | 550 | 550 | 600 | 600 | |
| $CO_2$ emitted (lb/MWh) | 931[i] | 830[i] | | 738[i] | 1030[i] | 811[i] | 1,886 | 1,773 | 1,843 | 0.81[j] | |
| Efficiency (%, HHV) | 34.3 | 38.5 | | 43.3 | 34.8 | 39.3 | 36.8 | 39.1 | | 39.5 | |
| Heat rate (Btu/kWh) | 9,950 | 8,870 | | 7,880 | 9,810 | | 9,276 | 8,721 | 8,963 | 8,630 | |
| TPC ($/kW) | 1,280 | 1,330 | | 1,360 | 1,330 | 1,442[a] | 1,549 | 1,575 | 1,763 | 1,703 | |
| FCF (% on TPC) | 15.1 | 15.1 | | 15.1 | 15.1 | 14.8 | 16.4 | 16.4 | 11.7 | 15 | |
| Fuel price ($/MMBtu) | 1.5 | 1.5 | | 1.5 | 1.0 | 1.2 | 1.8 | 1.8 | 1.5 | 1.53 | |
| Capacity Factor (%) | 85 | 85 | | 85 | 85 | 75 | 85 | 85 | 80 | 85 | |
| Electricity cost | | | | | | | | | | | |
| $COE_{CAP}$ (¢/kWh) | 2.60 | 2.70 | | 2.76 | 2.70 | | | | 2.927 | 3.43 | |
| $COE_{O\&M}$ (¢/kWh) | 0.75 | 0.75 | | 0.75 | 1.00 | | | | 1.051 | 1.14 | |
| $COE_{FUEL}$ (¢/kWh) | 1.49 | 1.33 | | 1.18 | 0.98 | | | | 1.344 | 1.32 | |
| COE (¢/kWh) | 4.84 | 4.78 | | 4.69 | 4.68 | 5.30 | 6.40 | 6.33 | 5.322 | 6.13[l] | |
| **With Capture** | | | | | | | | | | | |
| Net Power (MW) | 500 | 500 | 500 | 500 | 500 | 493 | 550 | 546 | 550 | 548 | 542 |
| $CO_2$ emitted (lb/MWh) | 127[i] | 109[i] | 104[i] | 94[i] | 141[i] | 107[i] | 278 | 254 | 277 | 0.10[j] | 0.07[j] |
| Efficiency (%, HHV) | 25.1 | 29.3 | 30.6 | 34.1 | 25.5 | 29.9 | 24.9 | 27.2 | | 31.2 | 30.2 |
| Heat rate, Btu/kWh | 13,600 | 11,700 | 11,157 | 10,000 | 13,400 | | 13,724 | 12,534 | 12,300 | 10,946 | 11,315 |
| TPC($/kWe) | 2,230 | 2,140 | 1,900 | 2,090 | 2,270 | 2345[a] | 2,895 | 2,870 | 2930 | 2,595 | 2,620 |
| FCF (% on TPC) | 15.1 | 15.1 | 15.1 | 15.1 | 15.1 | 14.8 | 17.5 | 17.5 | 11.7 | 15 | 15 |
| Fuel price ($/MMBtu) | 1.5 | 1.5 | 1.5 | 1.5 | 1.0 | 1.2 | 1.8 | 1.8 | 1.5 | 1.53 | 1.53 |
| Capacity Factor (%) | 85 | 85 | 85 | 85 | 85 | 75 | 85 | 85 | 80 | 85 | 85 |
| Electricity cost | | | | | | | | | | | |
| $COE_{CAP}$ (¢/kWh) | 4.52 | 4.34 | 3.85 | 4.24 | 4.60 | | | | 4.892 | 5.23 | 5.28 |
| $COE_{O\&M}$ (¢/kWh) | 1.60 | 1.60 | 1.45 | 1.60 | 1.85 | | | | 1.52 | 1.74 | 1.76 |
| $COE_{FUEL}$ (¢/kWh) | 2.04 | 1.75 | 1.67 | 1.50 | 1.34 | | | | 1.845 | 1.67 | 1.73 |
| COE (¢/kWh) | 8.16 | 7.69 | 6.98 | 7.34 | 7.79 | 8.80 | 11.88 | 11.48 | 9.278[d] | 9.25[m] | 9.54[g] |
| **Comparison** | | | | | | | | | | | |
| Avoid cost ($/tonne) | 41.3[f] | 40.4[f] | 30.3[f] | 41.1[f] | 39.7[f] | 49.7[f] | 68[c] | 68[c] | 55.7 | 44 | 46 |

[a]Total capital requirement ($/kW).
[b]SubC = subcritical; SC = supercritical; USC = ultra-supercritical; CFB = circulating fluidized bed
[c]$/ton. $CO_2$ transport, storage and monitoring is included and adds 4 mills/kWh to the LCOE
[d]COE Adder for $CO_2$ Transportation & Storage is 10.22 $/MWh
[f]Does not include costs associated with transportation and injection/storage.
[i,j]units are in kg/MWh and tonne/MWh respectively
[l]credits included for sulfur, NOx, $SO_2$, Hg and $CO_2$ are -0.03, 0.05, 0.07,0.03, 0.01 $/MWh respectively
[m]credits included for limestone, gypsum, NOx are 0.14, -0.04, 0.04 $/MWh respectively. Transportation and storage costs of 0.46 $/MWh are also included.
[g]credits included for limestone, gypsum, NOx, $SO_2$ are 0.14, -0.04, 0.04, 0.15 $/MWh respectively. Transportation and storage costs of 0.49 $/MWh are also included.

Pulverized Coal (PC) power plants are the most commonly used technology for power generation from coal. In a PC power plant, coal is pulverized and blown into a boiler where it is combusted with air to produce high pressure steam for power generation in a steam turbine. The flue gas from the boiler is typically passed through a heat exchanger to heat up the air going into the boiler, a desulfurization unit to remove $SO_2$, and, finally, a stack. The $CO_2$ capture at a PC plant has an amine capture unit that follows the desulfurization unit. The amine removes the $CO_2$ through a chemical reaction.

The pressure and temperature of the steam determine the relative efficiency of the power plant. Subcritical (SubC) plants produce steam pressure below 3200 psi and temperature below about 1025° F. Subcritical PC units have generating efficiencies between 33 and 37% (HHV).

Supercritical (SC) generating efficiencies range from 37 to 40% (HHV). Current state-of-the-art SC generation involves 3530 psi and 1050° F, resulting in a generating efficiency of above 38% (HHV) for Illinois #6 coal. A variation on SC combustion is oxy-combustion (OXY) in which coal is burned with oxygen instead of air which produces a flue gas of relatively pure $CO_2$ ready for capture, storage or direct use. Oxy-combustion can increase efficiency. The flue gas heat losses are reduced because the flue gas mass decreases as it leave the furnace and because there is less nitrogen to carry heat from the furnace.

Operating conditions above 1050° F are referred to as ultra-supercritical (USC). A number of ultra-supercritical units operating at pressures to 4640 psi and temperatures to 1112-1130° F have been constructed in Europe and Japan.

While not a traditional PC technology, circulating fluidized bed (CFB) power plants burn coal that is crushed rather than pulverized. CFBs are best suited for lower-rank, high ash coals such as lignite and some low-Btu sub-bituminous western coals.

For each study in Annexes A, B and C, two cases were analyzed: without capture and with capture. The following data is extracted from each study, for the two cases:

- Efficiency (E), defined on the higher heating value (HHV) basis.
- Heat rate (HR), in Btu/kWh, defined on the higher heating value (HHV) basis.

- Total plant capital cost (TPC), in $/kW;
- The fixed charge rate (FCF), in % per year;
- The capacity factor (CF) in %;
- The fuel price (FP), in $ per million Btu, defined on the higher heating value (HHV) basis;
- Net power output (W), in MW;
- Quantity of $CO_2$ emitted, in Ib/MWh;
- Levelised Cost of electricity (LCOE), in ¢/kWh, divided into:
  - LCOE due to capital investment ($LCOE_{CAP}$), in ¢/kWh;
  - LCOE due to fuel cost ($LCOE_{FUEL}$), in ¢/kWh;
  - LCOE due to operation and maintenance ($LCOE_{O\&M}$), in ¢/kWh;

The meanings of the other abbreviations are shown in the footnote of the table and in the notation section. The first two components of the cost of electricity can be calculated as follows:

$$LCOE_{CAP} = \frac{FCF \times TCP}{CF \times 24 \times 365} \frac{¢}{kWh} \qquad \text{(A.1)}$$

$$LCOE_{FUEL} = \frac{3412 \times FP}{E \times 10^4} \frac{¢}{kWh} \qquad \text{(A.2)}$$

$$COE_{O\&M} = LCOE - LCOE_{CAP} - COE_{FUEL} \quad \text{(A.3)}$$

The $CO_2$ avoided cost, expressed in $ per tonne of $CO_2$ is reported in the tables with reference to the associated base plant using the same technology.

# Annex B: Summary of IGCC Design Studies — As Reported

| STUDY | MIT | MIT | Rubin | NETL | NETL | NETL | EPRI | EPRI | EPRI | EPRI | SFA |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Technology[b] | GERQ[a] | GEQ | GEQ | GERQ | CoP | Shell | GERQ | GEQ | Shell | CoP | GEQ |
| Cost year basis | 2005 | 2005 | 2005 | 2006 | 2006 | 2006 | 2006 | 2006 | 2006 | 2006 | 2006 |
| **Without Capture** | | | | | | | | | | | |
| Net Power (MW) | | 538 | 538 | 640 | 623 | 636 | 630 | 600 | 620 | 612 | |
| $CO_2$ emitted (lb/MWh) | 832[i] | 822[i] | 822[i] | 1,755 | 1,730 | 1,658 | 1,789 | 1,944 | 1,714 | 1,796 | 0.80[j] |
| Efficiency (%, HHV) | 38.4 | 37.2 | 37.2 | 38.2 | 39.3 | 41.1 | | | | | 38.8 |
| Heat rate (Btu/kWh) | 8,891 | | | 8,922 | 8,681 | 8,304 | 8,832 | 9,600 | 8,466 | 8,870 | 8,807 |
| TPC ($/kW) | 1,430 | 1,567 | 1,567 | 1,813 | 1,733 | 1,977 | 2,190 | 1,894 | 2,234 | 1,938 | 1,842 |
| FCF (% on TPC) | 15.1 | 14.8 | 14.8 | 17.5 | 17.5 | 17.5 | 11.7 | 11.7 | 11.7 | 11.7 | 15 |
| Fuel price ($/MMBtu) | 1.5 | 1.2 | 1.2 | 1.8 | 1.8 | 1.8 | 1.5 | 1.5 | 1.5 | 1.5 | 1.53 |
| Capacity Factor (%) | 85 | 75 | 75 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 85 |
| Electricity cost | | | | | | | | | | | |
| $COE_{CAP}$ (¢/kWh) | 2.90 | | | | | | 3.75 | 3.24 | 3.83 | 3.32 | 3.71 |
| $COE_{O\&M}$ (¢/kWh) | 0.90 | | | | | | 1.29 | 1.13 | 1.22 | 1.15 | 1.24 |
| $COE_{FUEL}$ (¢/kWh) | 1.33 | | | | | | 1.33 | 1.44 | 1.27 | 1.33 | 1.35 |
| COE (¢/kWh) | 5.13 | 5.55 | 5.55 | 7.80 | 7.53 | 8.05 | 6.36 | 5.81 | 6.31 | 5.80 | 6.33[l] |
| **With Capture** | | | | | | | | | | | |
| Net Power (MW) | | 493 | 493 | 556 | 518 | 517 | 552 | 523 | 500 | 515 | |
| $CO_2$ emitted (lb/MWh) | 102[i] | 97[i] | 97[i] | 206 | 253 | 199 | 128 | 138 | 159 | 255 | 0.07[j] |
| Efficiency (%, HHV) | 31.2 | 32.2 | 32.2 | 32.5 | 31.7 | 32.0 | | | | | 32.6 |
| Heat rate, Btu/kWh | 10,942 | | | 10,505 | 10,757 | 10,674 | 10,463 | 11,300 | 11,156 | 10,895 | 10,478 |
| TPC($/kW) | 1,890 | 2,076 | 2,076 | 2,390 | 2,431 | 2,668 | 2,732 | 2,410 | 3,267 | 2,670 | 2,313 |
| FCF (% on TPC) | 15.1 | 14.8 | 14.8 | 17.5 | 17.5 | 17.5 | 11.7 | 11.7 | 11.7 | 11.7 | 15 |
| Fuel price ($/MMBtu) | 1.5 | 1.2 | 1.2 | 1.8 | 1.8 | 1.8 | 1.5 | 1.5 | 1.5 | 1.5 | 1.53 |
| Capacity Factor (%) | 85 | 75 | 75 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 85 |
| Electricity cost | | | | | | | | | | | |
| $COE_{CAP}$ (¢/kWh) | 3.83 | | | | | | 4.68 | 4.13 | 5.60 | 4.57 | 4.66 |
| $COE_{O\&M}$ (¢/kWh) | 1.05 | | | | | | 1.58 | 1.41 | 1.73 | 1.55 | 1.55 |
| $COE_{FUEL}$ (¢/kWh) | 1.64 | | | | | | 1.57 | 1.70 | 1.67 | 1.63 | 1.60 |
| COE (¢/kWh) | 6.52 | 7.19 | 7.19 | 10.29 | 10.57 | 11.04 | 8.74[d] | 8.21[d] | 9.00[d] | 8.65[d] | 8.29[l] |
| **Comparison** | | | | | | | | | | | |
| Avoid cost ($/tonne) | 19.3[f] | 22.6[f] | 22.6[f] | 32[c] | 41[c] | 42[c] | 31.54 | 29.3 | 51.7 | 40.7 | |

[a]GE radiant cooled gasifier for non-capture case and GE full-quench gasifier for capture case. All other cases for capture and non-capture have the same gasifier.
[b]GEQ = GE Total Quench; GERQ = GE Radiant Quench; CoP = ConocoPhillips
[c]$/ton. $CO_2$ transport, storage and monitoring is included and adds 4 mills/kWh to the LCOE
[d]COE Adder for $CO_2$ Transportation & Storage is 9.08 $/MWh, 9.81 $/MWh, 9.58 $/MWh and 8.90 $/MWh for GERQ, GEQ, Shell and CoP respectively
[f]Does not include costs associated with transportation and injection/storage.
[g]$CO_2$ transport+storage cost is 7.1 $/tonne $CO_2$
[h]includes 0.56 ¢/kWh as a $CO_2$ disposal cost
[i,j,k]units are in kg/MWh, tonne/MWh and g/kWh respectively
[l]credits included for sulfur, NOx, $SO_2$ and Hg are -0.03, 0.04, 0.01,0.01 $/MWh respectively
[m]credits included for sulfur, NOx, $SO_2$ and Hg are -0.04, 0.05, 0.01,0.01 $/MWh respectively. Transportation and storage costs of 0.44 $/MWh are also included.

Integrated Gasification Combined Cycles (IGCC) is an emerging technology. In IGCC, coal is converted in a gasifier into synthesis gas (CO, $CO_2$ and $H_2$). Impurities are removed from the syngas before it is combusted. This results in lower emissions of $SO_2$, particulates and mercury. It also results in improved efficiency of capture compared to PC. Unlike post-combustion capture from PC plants, a water gas shift reactor is added, in which CO reacts with $H_2O$ to form $CO_2$ and more $H_2$. Then a separation process, typically a physical absorption process, is used to remove the $CO_2$ from the “shifted syngas” stream. The $CO_2$ is then dehydrated for further compression, and the remaining gas stream of nearly pure $H_2$ is combusted in the gas turbine. Finally, waste heat is recovered to drive a steam turbine generator for additional power generation. A number of gasifier technologies have been developed. These include GE, Shell and ConocoPhillips (CoP). GE offers two designs: GE radiant (GERQ) and GE full-quench (GEQ). The GE and Shell gasifiers have significant commercial experience, whereas CoP technology has less commercial experience.

## Annex C: Summary of NGCC Design Studies — As Reported

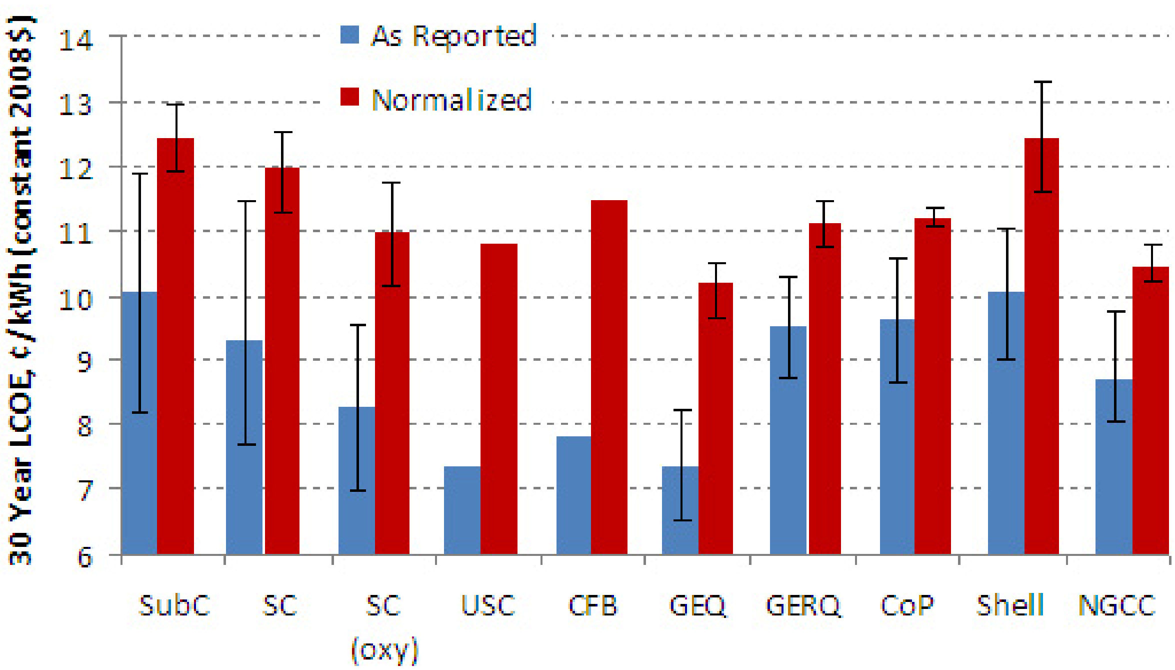
| **STUDY** | Rubin | NETL | EPRI | SFA |
|---|---|---|---|---|
| Cost year basis | 2005 | 2006 | 2006 | 2006 |
| **Without Capture** | | | | |
| Net Power (MW) | 507 | 560 | 550 | 543.2 |
| $CO_2$ emitted (lb/MWh) | 367[i] | 797 | 849 | 0.36[j] |
| Efficiency (%, HHV) | 50.2 | 50.8 | | 50.7 |
| Heat rate (Btu/kWh) | | 6,719 | 7,306 | 6,726 |
| TPC ($/kW) | 671[a] | 554 | 600 | 723 |
| FCF (% on TPC) | 14.8 | 16.4 | 11.7 | 15 |
| Fuel price ($/MMBtu) | 6[e] | 6.75 | 6 | 6.35 |
| Capacity Factor (%) | 75 | 85 | 80 | 85 |
| Electricity cost | | | | |
| $COE_{CAP}$ (¢/kWh) | | | 0.96 | 1.46 |
| $COE_{O\&M}$ (¢/kWh) | | | 0.27 | 0.39 |
| $COE_{FUEL}$ (¢/kWh) | | | 4.38 | 4.27 |
| COE (¢/kWh) | 6.03 | 6.84 | 5.61 | 6.13[l] |
| **With Capture** | | | | |
| Net Power (MW) | 432 | 482 | 467.5 | 482 |
| $CO_2$ emitted (lb/MWh) | 43[i] | 93 | 100 | 0.06[j] |
| Efficiency (%, HHV) | 42.8 | 43.7 | | 45.0 |
| Heat rate, Btu/kWh | | 7,813 | 8,595 | 7,581 |
| TPC($/kW) | 1091[a] | 1,172 | 1027 | 1,266 |
| FCF (% on TPC) | 14.8 | 17.5 | 11.7 | 15 |
| Fuel price ($/MMBtu) | 6[e] | 6.75 | 6 | 6.35 |
| Capacity Factor (%) | 75 | 85 | 80 | |
| Electricity cost | | | | |
| $COE_{CAP}$ (¢/kWh) | | | 1.64 | 2.55 |
| $COE_{O\&M}$ (¢/kWh) | | | 0.53 | 0.68 |
| $COE_{FUEL}$ (¢/kWh) | | | 5.16 | 4.81 |
| COE (¢/kWh) | 8.06 | 9.74 | 7.87[d] | 8.32[m] |
| **Comparison** | | | | |
| Avoid cost ($/tonne) | 62.6[f] | 83[c] | | 73 |

All NGCC plant uses 2 x advanced F class turbines & HRSG
[a]Total capital requirement (TCR) in $/kW. For Rubin, TCR is assumed to add 12% to TPC.
[c]$/ton. $CO_2$ transport, storage and monitoring is included and adds 4 mills/kWh to the COE
[d]COE Adder for Carbon tax, $CO_2$ Transportation & Storage is 1.25 and 4.1 $/MWh respectively
[e]in $/GJ
[f]Does not include costs associated with transportation and injection/storage.
[i,j]units are in kg/MWh and tonne/MWh respectively
[l]credits included for NOx is 0.01 $/MWh
[m]credits included for NOx is 0.01 $/MWh. Transportation and storage costs of 1.7 $/MWh is also included.

Natural Gas Combined Cycles (NGCC) has a higher thermal efficiency than PC and IGCC power plants and gas produces less $CO_2$ per unit of energy on combustion. As a result of these two factors it produces less $CO_2$ per MWh. Most new gas power plants in North America and Europe are of this type. In NGCC plant, natural gas is burned in a gas turbine with air to produce power. The waste heat of the flue gas from combustion is recovered in a heat recovery steam generator (HRSG) to drive a steam turbine generator for additional power generation. A post combustion capture plant will typically be an amine or ammonia absorption $CO_2$ removal unit that follows the heat recovery step. A gas-fed pre-combustion capture plant works in a manner analogous to an IGCC with syngas produced by a reformer rather than a gasifier.

## Annex D: Standardizing the LCOE estimates

The comparison between the results of the LCOE calculations "as reported" and on the "normalised" basis described in the main text are shown in the chart below. Normalisation reduces variation in the estimates for each technology, as indicated by the smaller size of the error bars. However, normalised numbers still show some variation due to those factors not covered by the adjustment. The normalised cost of electricity is mostly greater than "as reported" since the costs were all escalated to the 2008 cost basis.



## Annex E: Reported Capital Costs of Early IGCC Plants

The combined effects of scale and capture rate adjustment are shown in the table below, which is the source data for Figure 5 in Section 4 of the main text.

| | Scale MW | Base Costs $/kW | Adjusted costs (460MW, 90% capture) $/kW |
|---|---|---|---|
| US, no capture | 630 | 3750 | 6421 |
| US, 50% capture | 494 | 5000 | 6291 |
| US 90% capture | 275 | 7600 | 6590 |
| Germany, 90% capture | 330 | 6955 | 6343 |

*Note: due to the lack of information in the published sources it has not been possible to adjust fully for the factors described in Section 2 of this paper. The small range of variation in the adjusted costs may to some extent be coincidental.*

## Annex F: Details of Modelling of Variation of Costs with Capture Rate and Scale

This Annex describes a model of variation of capture costs with capture rate. The model is stylised and as such it attempts to represent essential features of the situation while omitting much detail. However the main relationships are based on more detailed engineering studies and so the essential features of the conclusions are likely to prove robust.

### Variation of capital costs with capture rate for IGCC

Work by GE has indicated that capital costs of an IGCC plant increase approximately linearly with capture rate. Work by GE and EPRI has also indicated that plant output and thermal efficiency decrease linearly with capture rate[26]. The effect of capture rates on costs of electricity has been modelled using these relationships.

[26] White, K (2008)

We define the relationships here as:

$$C(c) = K(1 + mc) \qquad (F.1)$$
$$P(c) = W(1 - pc) \qquad (F.2)$$
$$N(c) = E(1 - nc) \qquad (F.3)$$

Where:

*c* is capture rate expressed as a fraction where $0 \leq c < 0.9$. A capture rate significantly greater than 90% is likely to be much more costly with existing technology, and so is not considered here as a practical option for early plant.

| | **Variable for IGCC <u>with or without</u> capture** | **Value for IGCC <u>without</u> capture** | Positive constants representing the rates of change of each quantity with capture rate |
|---|---|---|---|
| Capital Cost in $ | C | K | m |
| Plant Output in kW | P | W | p |
| Thermal Efficiency | N | E | n |

From this the unit capital costs of the plant (U(c)) varies with capture according to:

$$\begin{aligned} U(c) &= \frac{C(c)}{P(c)} && (F.4) \\ &= \left(\frac{K}{W}\right)\left(\frac{1+mc}{1-pc}\right) \\ &= \left(\frac{K}{W}\right)(1+mc)(1+pc+p^2c^2+p^3c^3\ldots+p^nc^n) \\ &= \left(\frac{K}{W}\right)(1+mc+pc+mpc^2+p^2c^2+\ldots) \\ &= \left(\frac{K}{W}\right)I(c) && (F.5) \end{aligned}$$

Where *I(c)* is a cost increase function represented by the infinite series in the brackets in the preceding equation.

Unit capital cost thus increases with capture rate *$dU(c)/dc$* is unambiguously positive for all allowed values of *c)*. The increase is non-linear, with an increasing marginal cost of capture with capture rate ($d^2U(c)/dc^2$ is unambiguously positive for all allowed values of *c.)*

**Variation of levelised cost of electricity with capture rate**

Capital costs are the major component of levelised cost of electricity for an IGCC plant. We adopt a simplified treatment of levelised costs where the capital component is given by:

$$\frac{A.K}{W.H} \qquad (F.6)$$

Where:

*A* is an annuity factor, converting capital costs to an annual required capital recovery. It is assumed to take into account AFUDC, based on a fixed build profile.

*H* is annual hours of operation, assumed invariant with capture rate, so W.H annual output in MWh.

Variation of the capital component of levelised cost of electricity with capture rate is:

$$I(c)\left(\frac{A.K}{W.H}\right) \qquad (F.7)$$

We further assume that operating costs are a fraction (Q) of capital costs thus:

Operating costs = *Q.K* *(F.8)*

Fuel cost increase has slightly different behaviour from capex. However the difference is relatively small and fuel costs are only a small proportion of the total, so assuming linearity of fuel costs with capital introduces only a small error.

Adopting this simplified treatment of levelised cost of electricity:

$$A.K + G.K + S.K = (A + Q + S)\frac{K}{W.H}$$

Gives

$$LCOE_c = I(c)(A + Q + S)\frac{K}{W.H} \qquad (F.9)$$

From this:

$$LCOE_c = I(c).LCOE_0 \qquad (F.10)$$

**Cost of capture**

The cost of capture at capture rate $c$ is given by:

$$\begin{aligned} Capture\,Cost &= LCOE_c - LCOE_0 \\ &= LCOE_0(I(c) - 1) \end{aligned} \qquad (F.11)$$

Levelised cost of electricity and costs of capture thus shows the same form of increasing cost with capture rate as capital costs.

**Cost of avoided emissions**

Cost of avoided emissions is given by:

$$\frac{\left(COE_{with\,capture} - COE_{w/o\ capture}\right)\dfrac{\$}{MWh}}{\dfrac{\left(Q_{CO_2,\,w/o\ capture} - Q_{CO_2,\,with\ capture}\right)tonne}{MWh}} \qquad (F.12)$$

If the reference plant is the IGCC without capture the incremental cost of capture is given by the above expression for capture cost and avoided emissions are given by:

$$A(c) = F\left(\frac{1}{E} - \frac{1-c}{E - nc}\right)$$

$$=\left(\frac{F}{E}\right)c\left(1-\frac{m}{E}\right)\left(1-\left(\frac{m}{E}\right)c\right)^{-1} \qquad (F.13)$$

Where:

*F* is the specific emissions per kWh for the fuel.

Expanding this gives an expression of similar form to that for capital costs, where emissions avoided increase non-linearly with capture rate.

Combining expressions gives the cost of avoided emissions as:

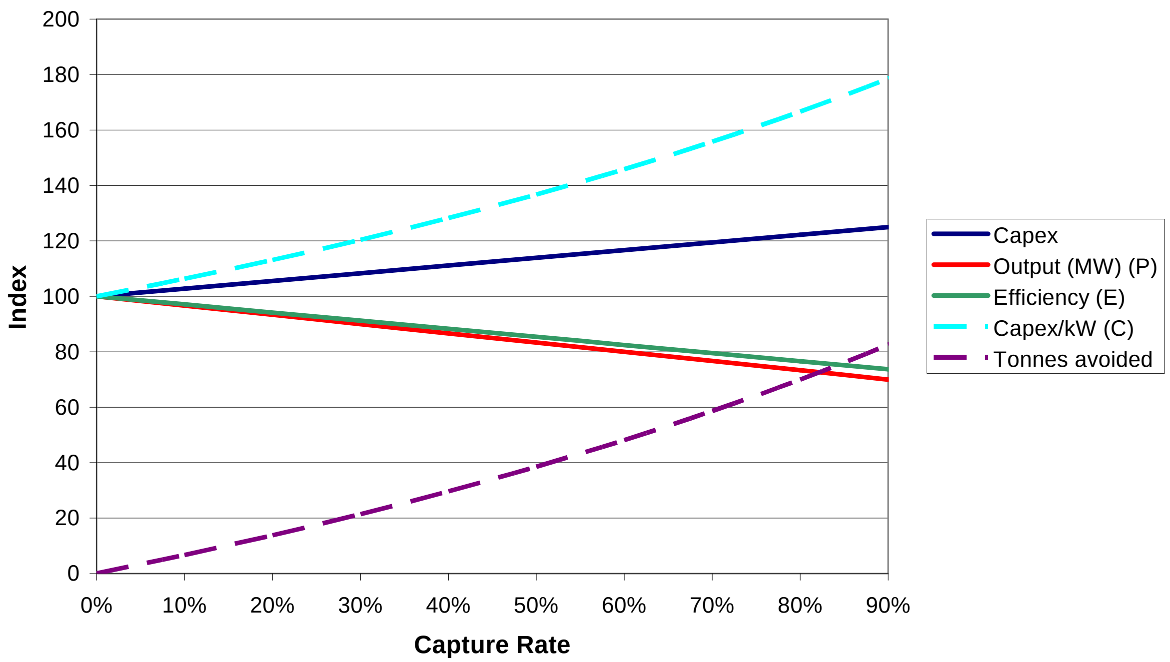
$$LCOE_0 \frac{(I(c)-1)}{A(c)} \qquad (F.14)$$

There is some evidence from the sources quoted that output falls less than linearly at higher capture rates. In that case the conclusion of no increase in unit costs with capture rate would be further supported.

The forms of these relationships are shown graphically in the following chart. The solid lines show the changes in capex output and efficiency defined in equations (F.1)-(F.3). The upper dashed line shows the unit capex derived from this, which increases non-linearly with capture rate as shown in the expression for U(c) derived above. Total LCOE (not shown) shows a similar trend.

Tonnes avoided increase with capture rate according to the trend shown by the lower dashed line. The cost per tonne avoided using an IGCC without capture is derived from the ratio between the increase in the top dashed line (where the increase represents additional costs of abatement) and the bottom dashed line (where the increase represents additional tonnes avoided).

**Variation of costs and cost drivers with capture rate (illustrative)**




A numerical example to illustrate the increase in tonnes avoided with capture rate is shown in the table below. $CO_2$ production at 0% capture converted to an index of 100 for clarity. The capture rates are shown for 0%, 45% to 90%. As efficiency decreases $CO_2$ production increases non-linearly (more than doubles on going from 45% to 90%). However this is more than offset by the increase in capture rates because at higher capture rates most of this additional $CO_2$ is captured. Consequently emissions avoided increases more than linearly with capture rate (decrease is greater from 45% to 90% than from 0% to 45%). A larger decrease in efficiency than is likely to be realised in practice is shown to illustrate the effect more clearly.

| Capture rate | 0% | 45% | 90% |
|---|---|---|---|
| Efficiency (%) | 39.5 | 33.2 | 26.9 |
| $CO_2$ before capture | 100 | 119 | 147 |
| Emissions after capture | 100 | 65 | 15 |
| Emissions avoided | 0 | 35 | 85 |

**Variation in costs with scale**

Costs are estimated to fall by a certain percentage for each doubling of capacity. Costs (both capex and opex) vary in the form of:

Where:
in this case b = 0.28

$a_n$ in the scale factor relative to the original unit

$K_0$ is the cost of the original non-scaled unit

r represents the average reduction in capital costs for a doubling of scale (17.5%)

## Annex G: $CO_2$ Capture from Natural Gas Processing Plant

Of the cases reviewed, Case 3 includes lower $CO_2$ concentration in the flue gas (~2.8%), and thus the larger volume of gas to be handled resulting in larger equipment sizes and higher capital costs. The utility cost is also high, because of the power consumption, fresh water consumption, and the solvent loss.

In case 4, the flue gas from the thermal oxidizer, at 1100$^{o}$F, needs to be first quenched to its adiabatic saturation temperature by water injection in a quench system. Saturated flue gas from the quench system then goes through the FGD absorber, where sulfur dioxide is removed by direct contact with an aqueous suspension of finely ground limestone. The chemical cost is high, because of the large volume of absorbents required. About two thirds of the cost is due to the use of limestone at the FGD and one third due to the use of caustic soda at the quench system. In addition to the high cost, case 4 may technically not be feasible for the following reasons:

- The oxidizer stack's flue gas contains ~ 3400 ppm of SOx, therefore ~ 100 ppm of $SO_3$ mist might form at the cooling step. Removal of $SO_3$ mist to 0.1 ppm level, which is what required before the flue gas passes to the $CO_2$ recovery process, might not be possible with currently available technology. High $SO_3$ mist also might cause severe corrosion problems.
- If oxidizer stack's flue gas contains hydrocarbon, the reaction between limestone and SOx may be hindered and SOx absorption efficiency may decrease.
- If oxidizer stack's flue gas contains sulfur or other particles, scaling problems are also expected.

In addition to the above, $CO_2$ recovery from flue gas presents challenges compared to $CO_2$ recovery from acid gases for the following reasons:

- Several emission sources compared to one single source as in case 5.
- Since flue gases contain 3-15% $O_2$, oxidative degradation can be significant. Acid gases do not contain $O_2$.

Capturing $CO_2$ from acid gases offers the following advantages compared with capture from the flue gases:

- The presence of $H_2S$ in the $CO_2$ streams is beneficial to EOR since it increase miscibility; therefore the amount of $H_2S$ that leaves the absorber with $CO_2$ can be adjusted to maintain effective miscible conditions in the reservoir. Flue gases do not contain $H_2S$.
- The $H_2S$ concentration in the acid gas is 25 % $H_2S$. Using the typical selectivity of MDEA, this ratio can be increased to 37% with partial acid gas treatment - and the overall volume would be reduced by about 38%. This leads to an effective capacity increase of the sulfur recovery units resulting in significant acid gas flaring reduction during Testing and Inspections or increasing plant processing flexibility.
- $CO_2$ recovery from acid gas stream using Acid Gas Enrichment technology is more practical and economical option for the intended $CO_2$ recovery due to the maturity of this technology and the availability of the required $CO_2$ volume in one stream.
- Only partial treatment (65%) of the entire acid gas stream is required to provide the target $CO_2$ volume. (The full treatment will result in more $CO_2$ recovery with additional capital and operating cost).