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# Reducing the costs of $CO_2$ capture and storage (CCS)

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# 1. EXECUTIVE SUMMARY

Australia has a significant existing coal fired power generation capacity, contributing 80 percent of the total electricity generation. Constructing new or retrofitted coal with $CO_2$ capture and storage (CCS) involves three key steps. Firstly $CO_2$ is extracted at some point in the coal to electricity conversion process, depending on the type of technology used. The $CO_2$ is then prepared for transport and stored in a suitable geological sink.

Australia has an enormous potential resource for geological storage of $CO_2$. However, like mineral resources, storage sites must be graded by their economic potential. Usable storage "reserves" will depend on the price of carbon and distance from the capture plant. The cheapest locations for $CO_2$ storage are the Latrobe Valley in the Gippsland Basin (A$7 per tonne of $CO_2$ avoided), the Southern Queensland in the Surat Basin (A$12 per tonne) and the Perth region in the Bunbury Trough of the Perth Basin (A$10 per tonne). Costs ranges in other regions can be very wide being based on limited cost and reservoir data. Significant exploration is required to narrow uncertainty and refine the cost estimates. However, the total exploration and appraisal costs for a site are small compared to the eventual total construction, operating and decommissioning costs.

This report focuses on the opportunities for one type of capture technology: post-combustion capture (PCC). PCC is the easiest to retrofit. As an end-of-pipe technology a PCC process also provides added flexibility. For instance, the capture plant can be switched off if need be, to allow for a larger output of the power plant at times when electricity demand and market prices are high.

Capture of 90% of the $CO_2$ present in flue gases from a coal-fired power plant results in a 30% efficiency loss when using a standard liquid absorbent process. This efficiency loss together with the increased capital investment leads to an increase of the cost of generation of 55 – 65 A$/MWh compared to a standard coal plant. The additional capital investment is the larger contributor of the two.

It is expected that efficiency losses will be improved over time due to development of novel liquid absorbents, absorbent tailored optimisation of the process conditions and optimised integration of the capture process with the power plant. Capital cost reductions are expected to be achieved via integration of sulphur removal with $CO_2$-removal, use of lower cost materials for the absorption equipment and use of more reactive solvents which will result in smaller equipment sizes for the absorber.

Not taking into account these improvements, putting together the capture and storage cost ranges gives a CCS cost of abatement of 80 – 140 A$/tonne $CO_2$. The low end of this range represents a retrofitted PCC plant (i.e. the cost of the existing coal plant is not included) near a low cost storage site.

The report was prepared as input to the Garnaut Review Update in a relatively short time frame, and therefore is not intended to be comprehensive.

# 2. INTRODUCTION

## 2.1 Coal fired power generation in Australia

Power generation in Australia is 80% coal based (brown and black). The presence of easy to mine coal reserves and the close proximity of power plants to both coal mines and end users make electricity generation costs in Australia amongst the lowest in the world. Table 1 shows key data for Australia's coal fired power generation fleet.

Table 1 Key data for Australian coal fired power stations (Cottrell et al., 2009)

| Parameter | Data |
|---|---|
| **Generation capacity** | 28 GW |
| **Electricity production** | 170 TWh/yr |
| **Average generation efficiency and $CO_2$ emission** | |
| - **Black coal** | 35.6%; 0.9 $tCO_2$/MWh |
| - **Brown coal** | 25.7%; 1.3 $tCO_2$/MWh |
| **Overall $CO_2$ emission and # of sources** | 170 $MtCO_2$/yr from ~60 flue gas streams |

# 3. THE CCS TECHNOLOGY CHAIN

In the CCS technology chain, $CO_2$ is extracted at some point in the energy conversion train, depending on the type of energy technology used. It is then prepared for transport and stored in a suitable geological sink, where it is kept for a sufficiently long period. As such, CCS limits or altogether avoids the release of $CO_2$ into the atmosphere as a result of combustion processes. It is thereby possible to sustain the future use of fossil fuels (coal, gas and oil), while alternative zero low emissions technologies are developed. In case of biomass based fuels the capture and storage of $CO_2$ will result in a net decrease of $CO_2$ in the atmosphere.

The overall, general concept involves three steps, which are described below.

## 3.1 Capture of $CO_2$

Large amounts of $CO_2$ are emitted in diluted streams at atmospheric pressure, for instance, in flue gases from power stations, as the fuel is usually burned in air. To simplify the ensuing steps of transport and storage this needs to be concentrated. A concentrated $CO_2$ product at an absolute pressure of 80 bar and higher is preferred.

Therefore also a compression step is needed to achieve the right transport/storage conditions.

## 3.2 Transport of $CO_2$

Transport of $CO_2$ is needed as the emissions of $CO_2$ will not necessarily be, at the same location as the storage site. A transport system is therefore needed to link the $CO_2$-sources to the $CO_2$-sinks.

## 3.3 Storage of $CO_2$

Storage of $CO_2$ should be such that it remains isolated from the atmosphere for a suitably long period. The options for this are mainly in the underground, i.e. exhausted oil and gas fields, deep coal beds and aquifers. $CO_2$ might also be chemically bound to certain rock materials, which is the means of $CO_2$-control over geological time scales.

Over the past decade CCS has become a valuable part in the portfolio of technologies to reduce $CO_2$-emissions. Both capture and transport of $CO_2$ can be done using technologies which are commercially available. For instance, $CO_2$-separation technologies are commonplace in the oil and gas industry. There is a need to adapt and optimise these separation technologies for CCS-applications in coal fired power stations. As regards transport: Various modes of $CO_2$ transport are possible: pipeline, ship, tanker and the focus is on the infra-structural requirements. $CO_2$-storage can be done in exhausted oil and gas fields, coal beds and aquifers. These technologies are at various stages of development. Injection of $CO_2$ into oil fields has been practiced for more than three decades in the USA, under commercial conditions. The first commercial application of $CO_2$ storage in an off-shore aquifer has been successfully been running since 1996 at the Sleipner gas field in Norway. A major challenge is to achieve societal acceptance of the concept of underground $CO_2$-storage.

## 3.4 Global status of CCS technology deployment

The Global CCS institute has provided a recent update of the status of CCS-projects (GCCSI, 2011). In 2010, 234 active or planned CCS projects have been identified across a range of technologies, project types and sectors. Seventy-seven of these projects are Large Scale Integrated Projects (LSIP), encompassing a complete CCS-chain. There are eight operating LSIP’s and a further four projects are in the execution stage. All eight operating LSIPs and the four in execution are linked to the oil and gas sector: they either capture $CO_2$ via natural gas processing, or they inject $CO_2$ for EOR. There are 42 LSIP’s in development planning in the power generation sector. Although it indicates a number of projects have been newly identified during 2010 (across the various stages of the technology innovation chain), it is also reveals that many previously commenced projects have been delayed or cancelled due to investment uncertainty or due to technological reasons. In Australia the Gorgon Carbon Dioxide Injection Project is in the execution stage.

# 4. $CO_2$ STORAGE POTENTIAL IN AUSTRALIA

Studies have shown that Australia has an enormous potential resource for geological storage of carbon dioxide, with space available for hundreds of years of emissions. However, just as we differentiate between petroleum resources and petroleum reserves, it is necessary to delineate the equivalent volume for $CO_2$ storage through the application of economic screening. Usable storage "reserves" will depend on the price of carbon and distance from the capture plant, and not just be the area of a basin times the thickness times a standard efficiency factor.

A study by Neal et al. (Neal et al., 2010) undertaken as part of the Australian Carbon Storage Taskforce estimated that the cheapest locations for $CO_2$ storage are the Latrobe Valley in the Gippsland Basin (A$7 per tonne of CO2 avoided), the Southern Queensland in the Surat Basin (A$12 per tonne) and the Perth region in the Bunbury Trough of the Perth Basin (A$10 per tonne). At much greater expense, when all the emissions from NSW are combined and injected into a single formation, injecting $CO_2$ into the deep horizon of the Cooper Basin is estimated to cost A$53 per tonne. It may be more viable to transport NSW emissions to the Gippsland Basin. Overall, the estimates of the costs for combinations of sources range from A$16 to A$151 per tonne of $CO_2$ avoided on the East Coast, and A$10 to A$4,400 per tonne of $CO_2$ avoided on the West Coast (Neal et al., 2010). These cost estimates are based on limited cost and reservoir data and have a large margin of error. Nevertheless it can be seen that there is considerable variation and a range of 10-50 A$ per tonne $CO_2$ avoided is applicable to the more attractive storage locations. Significant exploration that includes drilling appraisal wells is required to narrow uncertainty and refine the cost estimates. In general, the total exploration and appraisal costs for a site are small compared to the eventual total construction, operating and decommissioning costs.

Initially geological storage considered structural traps, this is the type of trap routinely used for underground natural gas storage overseas and at the Iona natural gas storage field in Victoria. However, research has identified the potential importance and security of capillary and dissolution trapping. These trapping mechanisms are being demonstrated in the next phase of the CO2CRC Otway Project in Victoria.

# 5. $CO_2$ CAPTURE

$CO_2$-capture processes or decarbonisation technologies can be divided into three main categories or general process routes:

- Post-combustion processes. Carbon dioxide is captured from a flue gas at low pressure (1 bar) and low $CO_2$-content (3-20%), in general. The separation task is to remove $CO_2$ from a mixture of mainly nitrogen and oxygen, but also the impact of flue gas impurities ($SO_x$, $NO_x$, particulates) needs to be taken into account.

- Pre-combustion processes. Carbon dioxide is captured from a gas mixture with predominantly $H_2$ gas at high pressure (15-40 bar) and medium $CO_2$-content (15-40%) or carbon is produced directly from fossil fuels. Apart from the $CO_2/H_2$

separation, the feed gases also contain CO, $H_2S$ and sometimes other sulphur components.

- Denitrogenation processes, more often referred to as oxyfuel. A concentrated stream of carbon dioxide can be produced by the exclusion of nitrogen before or during the combustion/conversion process. The difference with the previous process routes is that here the separation is targeted to produce oxygen from air (i.e. separation of oxygen from mainly nitrogen), thereby avoiding the need for $CO_2$ separation. An additional advantage might be that in the same process all impurities are captured, as the process is essential free of flue gas.

## 5.1 The case for post-combustion $CO_2$ capture

The post-combustion capture process (PCC) is the process which is the easiest to use as a retrofit option, allowing $CO_2$ to be captured from the existing coal fired power stations. The state-of-the-art $CO_2$ separation technology is based on a liquid absorbent which undergoes a reversible chemical reaction with $CO_2$. These chemical absorption processes are in general applicable to gas streams at both high and low overall process pressure, but most applicable where a $CO_2$ is present at low concentration. The regeneration of the chemical absorbent is carried out at elevated temperatures (100 – 140 $^{o}$C) and pressures not very much higher than the atmospheric pressure.

The typical flow sheet of $CO_2$ recovery using chemical solvents is shown in Figure 1.

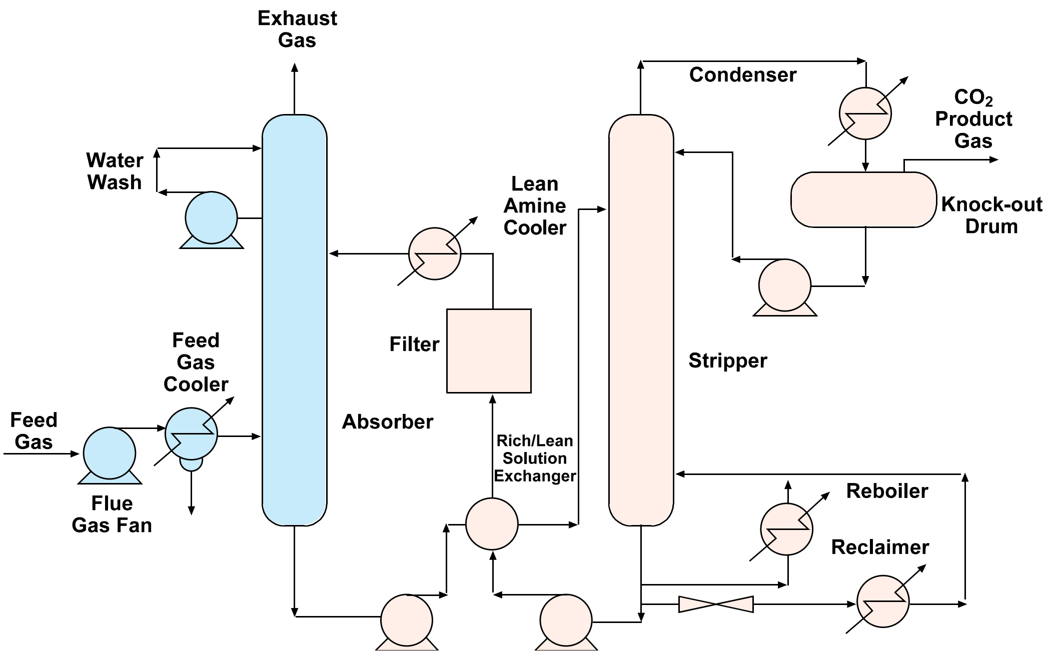


Figure 1 Process flow diagram for $CO_2$ recovery from flue gas with chemical solvent (Bailey and Feron, 2005)

The liquid absorbent technology is commercially available and already in use for a wide range of gas separation applications. Hence, it presents a relatively low technology risk for deployment in comparison to other less developed technologies.

Figure 2 shows a typical flow sheet for an Australian coal fired power plant fitted with PCC.

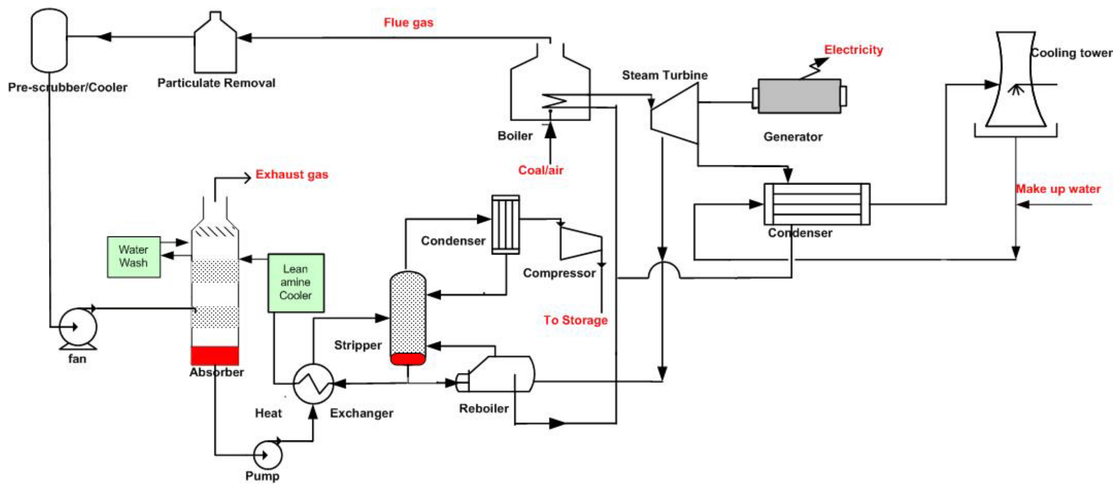


Figure 2 Power plant with PCC under Australian conditions (Feron and Hooper, 2009)

PCC has never been used at full-scale and integrated in a coal fired power plant. Capture of 90% of the $CO_2$ present in flue gases from a coal-fired power plant would result in a 30% efficiency loss when using a standard liquid absorbent process. The resulting loss of the output product, i.e. the electricity sent out to the customers, is an important draw-back and quite different from other applications of this technology, where product losses would be minimal.

As an end-of-pipe technology a PCC process also provides added flexibility. For instance, the capture plant can be switched off if need be, to allow for a larger output of the power plant at times when electricity demand is high and market prices are high. This is a beneficial feature in the highly competitive Australian Electricity Market. Such flexible operation allows the technology to be in tune with market requirements.

A liquid absorbent based technology also allows for easy incorporation of technological improvements. As the performance of liquid absorbent will gradually be improved, replacement of the liquid absorbent in the existing equipment is a practice which is widely used in other applications. The improved performance can be used to increase output or increase overall efficiency. As such the technology is applicable in new and retrofit applications, thus providing a broad pathway towards $CO_2$-emission reductions from coal fired power stations. There is large global targeted R&D activity addressing the challenges for application of liquid absorbent based technologies for $CO_2$ capture. These challenges are not only related to the efficiency penalty, but also to the chemical and thermal stability of the liquid in the challenging power plant environment. Australia has furthermore limited emissions controls on coal fired power stations as a result of the high quality of the coal used. The use of a liquid absorbents will most likely require additional control of flue gas components like sulphur dioxide prior to the capture process. The main challenge for PCC is without doubt the overall cost of the process as a result of the additional investments and loss in power plant output.

# 6. ESTIMATED COSTS FOR PCC IN COAL FIRED POWER PLANTS IN AUSTRALIA

The costs for PCC in power plants are usually evaluated for a fixed capture rate (typically 90%) by comparing the costs of power generation before and after PCC implementation. The difference between cost of generation and $CO_2$-emissions in both cases then allows the costs of $CO_2$-avoidance to be determined. Capture and compression costs generally make up 2/3 of the overall costs for the avoidance of $CO_2$-emissions and therefore dominate the overall economics of a CCS-chain. In recent years costs of engineering equipment and design services have escalated. Results from studies for a full-scale PCC-application on specific coal fired power stations in Australia are not available in the public domain. Although detailed publicly available information on costs for PCC under Australian conditions are lacking, techno-economic evaluations have been carried out with a view to provide bench-mark costs for PCC (Dave and et al. , 2011a). Table 2 gives an overview of the assumptions used in the techno-economic analysis.

Table 2 Assumptions for techno-economic analysis of PCC (Hayward et al., 2011, Dave and et al. , 2011a)

| **Design CO2 capture rate** | **90%** |
|---|---|
| **Thermal energy for capture process** | 4 GJ/t$CO_2$ |
| **Delivery temperature pressure $CO_2$ product** | 40 $^oC$ / 10 MPa |
| **Fuel costs** | Black coal: 1.38 A$/GJ |
| **Discount rate** | 8% |
| **Amortisation period** | 35 years |
| **Plant capacity factor** | 84% |

The techno-economic analysis has involved a range of power plants from subcritical steam conditions to ultra-supercritical steam conditions; with 500 to 600 MW installed capacity. Existing coal-fired power plants in Australia are almost entirely of the subcritical type with the most recent ones utilising supercritical steam conditions. The type of cooling will influence the costs of power generation and both cooling water and air cooling options have been analysed. The PCC process was based on a generic 30% MEA used in a standard absorber/desorber operation. Typical value ranges for the generation efficiency, specific capital costs and costs of power generation with and without capture are given in Table 3.

Table 3 Typical efficiencies, costs of generation and avoided $CO_2$ emission costs under Australian conditions (Hayward et al., 2011, Dave and et al. , 2011a, Feron and Hooper, 2009)

| | | |
|---|---|---|
| **Generation efficiency without PCC** | 35-41% | Efficiency range determined by type of steam cycle and type of cooling |
| **Generation efficiency with PCC** | 25-29% | |
| **Capital costs without PCC** | 2300-3000 A$/kW | Cost range determined by type of steam cycle and type of cooling |
| **Capital costs with PCC** | 4900-5900 A$/kW | |
| **Cost of generation without PCC** | 21-66 A$/MWh | Lower costs refer to fully amortised power plant. Higher costs refer to new-built power plant |
| **Cost of generation with PCC** | 75-129 A$/MWh | |
| **Avoided $CO_2$ emissions cost** | 68-92 A$/t$CO_2$ | |

The implementation of PCC with 90% capture of the $CO_2$-emissions from a coal fired power plant resulted in an increase of the cost of generation of approximately 55 – 65 A$/MWh and avoided emissions costs of approximately 70 – 90 A$/ton $CO_2$. The higher costs of generation are only to a small extent due the decreased power generation efficiency (typically 30 % equivalent to 10-12 %-points decrease in efficiency and a 40% increase in the coal consumption per unit electricity). Table 3 clearly shows that the capital costs will double with the implementation of PCC and this constitutes the main component in the increased costs of generation.

## 6.1 Reducing the energy penalty due to $CO_2$ capture and compression

The energy penalty due to capture and compression is perhaps the most important item for power companies to consider as this leads to an immediate loss in revenue, even without considering the capital costs for the capture plant. It also results in an increased coal utilisation per unit of electricity, thereby increasing the environmental impacts of coal fired power stations. The energy penalty is due to:

- The power requirement in the absorption process which is in general determined by the rotating equipment used in the process (blowers for flue gas, pumps for liquid absorbent and cooling water)

- The thermal energy needed for the regeneration of liquid absorbents as this is extracted from the power plant steam cycle and hence not available to generate electricity

- The power needed for the $CO_2$ compression process.

The liquid absorbent technology is a well understood process, allowing for a more detailed thermodynamic assessment of the potential for improvement when the technology is applied to a coal-fired power station for capture of $CO_2$ from the flue gas. Results of such an assessment are given in Figure 3 which shows the energy requirement for the capture process as the technology development progresses. The anticipated improvements are resulting from development of novel liquid absorbents, absorbent tailored optimisation of the process conditions and optimised integration of the capture process with the power plant. Gradual technology development will involve development of designer amine based liquid absorbents, phase change solvents, ionic liquids and identifications of the optimal process conditions for these novel liquid absorbents.

Also shown is the thermodynamic minimum energy requirement for the separation and compression process. It is indicated in Figure 3 that considerable technology improvements are already underway since 1990, bringing the energy requirement of $CO_2$ capture and compression down from 0.4 MWh/ton $CO_2$ to 0.3 MWh/ton $CO_2$ by 2015. The technology status in 1990 was determined by the market for commercial grade $CO_2$ production for food applications or other applications, which are small scale, typically less than 1 % $CO_2$ capture of the flue gas from a power station.

The potential market for the capture process in case of large scale $CO_2$ capture from power stations has resulted in further development of technology. The improvements have been realised by optimisation of the standard mono-ethanolamine based liquid absorbent, but also through the development of alternative liquid absorbents. Further improvements are expected to bring the energy requirement down to 0.2 MWh/ton $CO_2$ by 2030 which is still double the minimum energy required for the separation and compression process. It is anticipated that such improvements are possible through further liquid absorbent development, process optimisation and integration of $CO_2$ capture and compression, made possible through the use of more thermally stable liquid absorbents. The energy performance improvement over the standard process in 2030 represents effectively a halving of the energy penalty compared to the standard process in 1990. The energy penalty for the capture and compression of $CO_2$ can then be reduced from 10-12% to 5-6%.

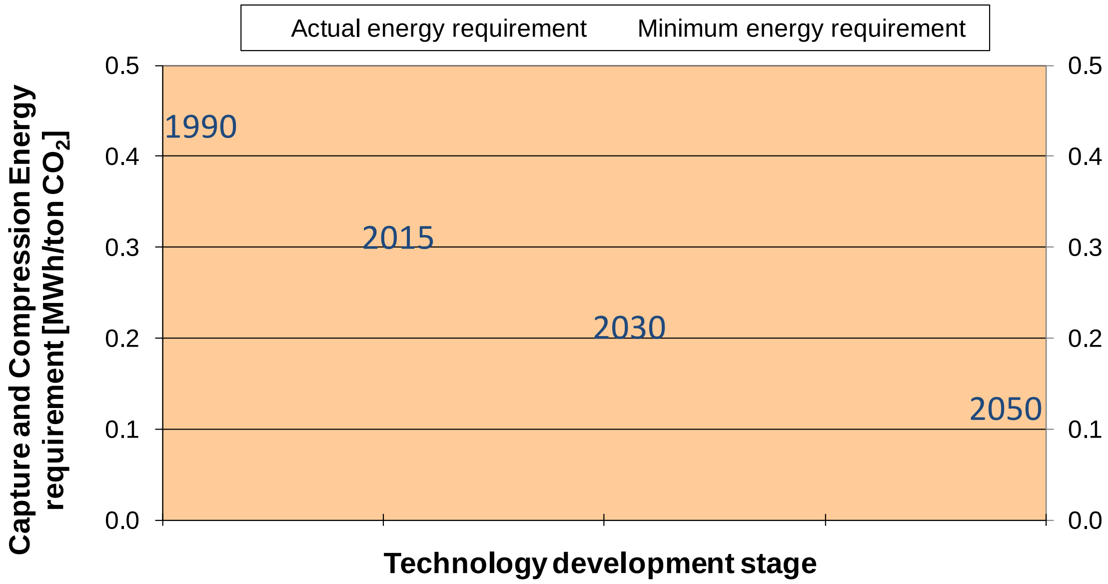


Figure 3 Expected improvement potential for liquid absorbent based PCC technology (Feron, 2010)

## 6.2 PCC cost reduction

The impact of the energy performance improvement of the capture process as outlined in the previous section results in a reduction in the operating costs of the capture process. It will also proportionally reduce the additional coal resource utilisation. Table 4 gives results of a case study for a new coal fired power station without and with 90% $CO_2$ capture and compression (August 2010). The cost of generation will increase by 64 A$/MWh resulting a cost for $CO_2$-avoidance of 91 A$/ton $CO_2$. The 10% points drop in efficiency represents an increase in coal resource utilisation of 36% and identical increase in the fuel costs.

Table 4 Example new coal fired power plant performance in Australia with and without capture (Dave and et al. , 2011b)

| | No $CO_2$ capture | With 90% $CO_2$ capture |
|---|---|---|
| **Net power output** | 571 MWe | 420 MWe |
| **Net plant efficiency (HHV)** | 38.1% | 28.0% |
| **$CO_2$ emissions** | 810 $kg/MWh_{nett}$ | 105 $kg/MWh_{nett}$ |
| **Capital costs** | 2529 A$/kW | 5046 A$/kW |
| **Generation costs** | 56.4 A$/MWh | 120.3 A$/MWh |
| **Cost of $CO_2$ avoidance** | 91.3 A$/t$CO_2$ | |

Figure 4 gives an overview of the various contributions to the cost of electricity generation. It can be seen that the capital costs for the power station with capture will be double that of the power station without capture. In Australia, with its low fuel costs, the capital costs for the capture plant and the additional maintenance costs are a major contributor to the increased cost of generation.  The absence of flue gas desulphurisation in Australian coal fired power plants means that the flue gas requires additional pre-treatment before the $CO_2$ capture process. The large volumes of flue gases will lead to large equipment sizes for both the $CO_2$ absorber and flue gas desulphurisation. This equipment is the main contributor to the capital costs.

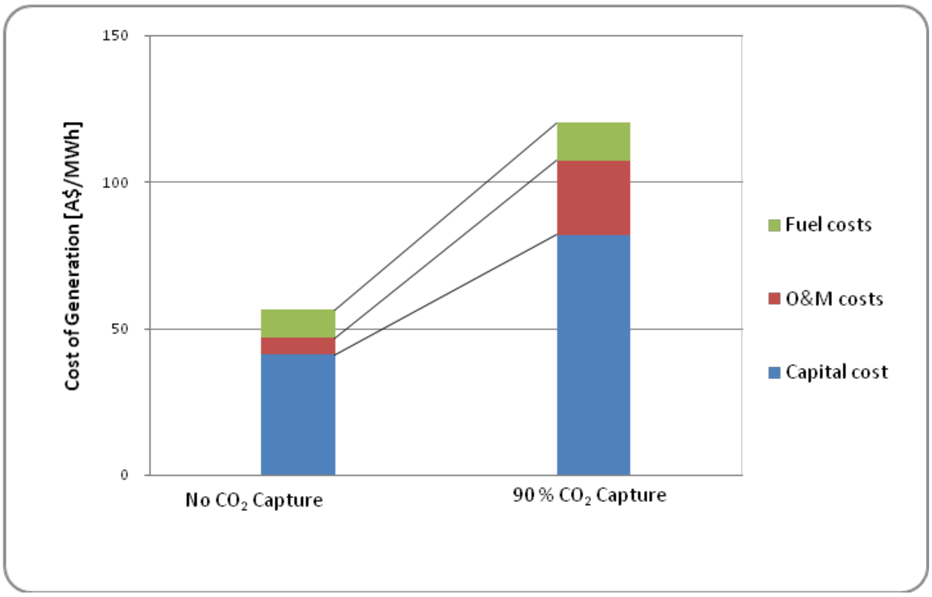


Figure 4 Overview of the various contributions to the cost of generation for a new coal fired power station (Dave and et al. , 2011b)

There is a potential to halve the costs of capture by a combination of:

- halving the energy penalties as shown in the previous section
- halving the capital costs.

The capital costs can be reduced by a combination of measures:

- integrating the sulphur removal with $CO_2$-removal resulting a single absorber for both acid gases,
- use of cheap materials for the absorption equipment (columns and internals),
- use of more reactive solvents which will result in smaller equipment sizes for the absorber.

It must also be anticipated that with the increased experience through technology deployment the design procedures will be streamlined and risks will be reduced. This will in itself lead to cost reduction for the overall process.

# 7. CONCLUSION

Capture and storage of $CO_2$ has the potential to significantly reduce $CO_2$-emissions from Australian power stations. Capture and compression of $CO_2$ will cost between 70 and 90 A$/ton $CO_2$, the lower range costs are representative for a retrofit of an existing coal fired power station power station, the high range costs for a new coal fired power station. There is the potential to halve these costs by targeted research and development. Transport and storage of $CO_2$ will typically add between 10 and 50 A$/tonne $CO_2$ to these costs, leading to overall costs in the range 80 – 140 A$/tonne $CO_2$.

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