

## Optimisation of the Cost / Power Trade-Offs Associated with Solvent Absorption Carbon-Capture Plants

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The addition of carbon capture and storage to a power station will impact the net power generated and increase the cost of electricity produced from the power stations. A method is presented to help design the carbon capture and compression process retrofitted to the power station. It combines simulation, automated heat integration and multi-objective optimisation. The methodology is applied to a coal fired power station combined with potassium carbonate based solvent absorption. The energy penalty, the ratio of the change in efficiency of the power station due to the addition of CCS over the efficiency of the original power station, to capture 90 % of the CO<sub>2</sub> emissions can be reduced from 38 to 14 % using this method. However to minimise the cost of electricity, more modest reductions in energy penalty of 22 – 25 % are recommended.

### 1. Introduction

CO<sub>2</sub> separation using solvent based absorption is considered to be the leading technology for current implementation of CCS for post-combustion capture from power stations. However it reduces the efficiency of the power station due to the impact of the additional heat and power required to separate, capture and compress the CO<sub>2</sub>. There is also a significant capital and operating cost associated with the new CCS equipment which will increase the power stations cost of electricity (COE). When designing a CCS plant for a particular power station there are many objectives that need to be considered; the capital cost of the new infrastructure, the operating costs, net power generated, the operability of the power station and the environmental impact of the CCS plant. When determining the design of the power station with CCS there will often be conflict between these objectives and the impact of a specific variable may not be certain until a full analysis of the system is completed. For example, the solvent regenerator pressure will have impacts on the amount of heat required for regeneration, the temperature of the heat required, the CO<sub>2</sub> compressor power and the related capital costs. These conflicting impacts will increase/decrease the regenerator pressure and the optimum pressure is not immediately apparent.

Steam cycle design/optimisation is important to maximise the power generated by the power station with CCS. Linnhoff and Alanis (1989) used pinch analysis in the design of power stations; steam extraction rates were calculated assuming a pinch occurs at each steam condensing temperature, which is not always the case for power stations

with CCS. The total site analysis method presented by Dhole and Linnhoff (1993) and Klemeš et al. (1997) is also used for steam cycle design, but is geared mainly for cogeneration and does not take into account the sensible heating in the production and use of steam. Kapil et al. (2010) and Botros and Brisson Ii (2010) included the sensible heat required for the steam production. They calculated the mass flowrates through the steam cycle using a bottom-up or iterative procedure. The methodology described below includes the sensible heat in both the generation and use of steam and calculates the mass flowrates to maximise the steam turbine power.

## 2. Methodology

The methodology created by the CO2CRC to better design power stations including CCS plants involves a combination of simulation, automated heat integration using linear programming and multi-objective optimisation (MOO) as arranged in Figure 1. This approach is based on work by Bhutani et al. (2007), who combined commercial simulation packages with a MOO program, however the approach created by the CO2CRC has the added dimension of automatic heat integration.

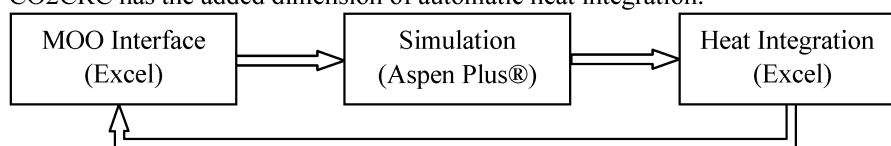


Figure 1: Optimisation approach for power stations with CCS.

The power station and the CCS plant are modelled using Aspen Plus®, the heat exchangers are modelled as simple heaters and coolers; the form of the heat exchanger network is not assumed at this stage of the process. The heat curves from the simulation are extracted into an Excel based heat integration program. The program uses the heat curves to generate grand composite curves (GCC) of the process. The steam cycle, which could be a new steam cycle or an existing steam cycle in the case of a retrofit, details are added to the Excel program. The program then determines for the steam cycle provided, the maximum amount of power that can be generated from the power station GCC, by constructing a steam composite curve (SCC) under the GCC (refer to Figure 2). The SCC is the equivalent of the GCC for the steam cycle, including the heat required to generate the steam and the heat available from steam extracted from the turbine. For a given steam cycle with defined steam pressures both the amount of heat required for the steam generation/use and the amount of power generated by the steam turbine are linear. Therefore the rates of steam generated/used at each level to maximise the net power produced from the steam turbine can be determined using a simplex algorithm. The method is described in more detail in Harkin et al. (2010).

The heat integration program estimates capital and operating costs of the CCS infrastructure, including costs for turbine modifications and the heat exchanger network required to provide the maximum amount of power from the power station. The results are analysed using a MOO program to determine the optimal solutions. The MOO algorithm used is an Excel based genetic algorithm based on NSGA-II code.

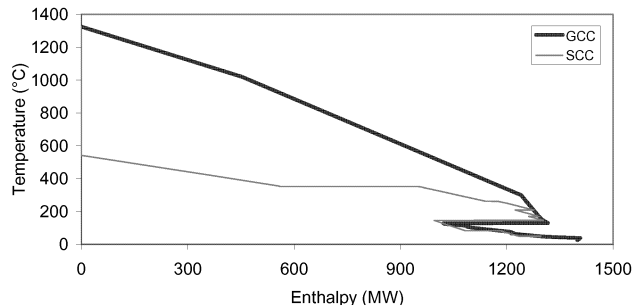


Figure 2: Output of the heat integration program to determine the steam cycle shown by the SCC, to maximise the net power for the given GCC of the power station with CCS.

### 3. Case Study Description and Results

The methodology described in Section 2 is applied to a brown coal fired power station, typical of those found in Victoria, Australia. Victorian brown coal has high moisture content of 60 wt % and due to its low cost, the power stations have been designed with low capital cost and low efficiencies to minimise the COE. The low sulphur coal found in this region also means that the power stations do not require desulphurisation equipment.

The CO<sub>2</sub>CRC has been investigating the use of potassium carbonate for CO<sub>2</sub> capture from power stations as it has many potential advantages over more commonly used amine based solvents; including low volatility, lower cost, lower rates of degradation and the ability to absorb the incoming SO<sub>x</sub> and NO<sub>x</sub> compounds and form potentially useful potassium sulphates/nitrates avoiding the need for additional equipment for removal of the SO<sub>x</sub> and NO<sub>x</sub>. This case study uses the traditional 30 wt% potassium carbonate process and therefore this process will generally require more regeneration energy than amine based solvents.

This case study considers a nominal 500 MWe power station prior to the addition of the CCS equipment. The captured CO<sub>2</sub> will be compressed to 100 bar for transport. The steam cycle in this optimisation problem is set with a main steam flowrate equal to the existing main steam rate to minimise the changes to the power station. When the potassium carbonate based CCS equipment capturing 90 % of the CO<sub>2</sub> is retrofitted to the power station, without consideration of heat integration/optimisation, the net power from the power station is reduced to 310 MWe, a 38 % reduction in net power.

Two optimisation problems were reviewed and each problem had two objectives;

- Opt. 1. Maximise the CO<sub>2</sub> capture rate and maximise the net power generation.
- Opt. 2. Maximise the CO<sub>2</sub> capture rate and minimise the  $\Delta$ COE.

There were nine variables used in the optimisation;

Solvent lean loading (0.1-0.415 mol HCO <sup>-</sup> /mol K <sup>+</sup> )	Solvent temp. (40-71 °C)
Regenerator pressure (0.5-8.25 bar)	Abs. feed gas temp. (40-71 °C)
Regenerator feed temp.(70-133 °C)	$\Delta T_{\min}$ (6-36 °C)
Abs. & Regenerator packing height (10-47.5 m)	Solvent flowrate (800-7000 kg/s)

Selected results from the first and the second optimisation problems are provided in Figures 3 – 5.

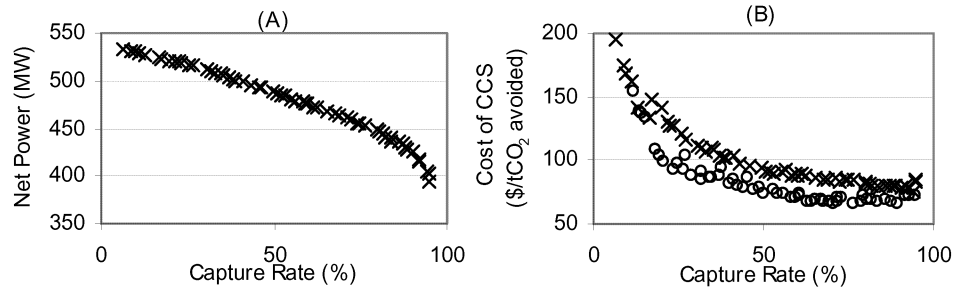


Figure 3: (A) Pareto optimal solutions for the net power generation versus CO<sub>2</sub> capture rate (Opt. 1). (B) The cost of CCS for the optimal solutions for Opt. 1(x) & Opt. 2(o).

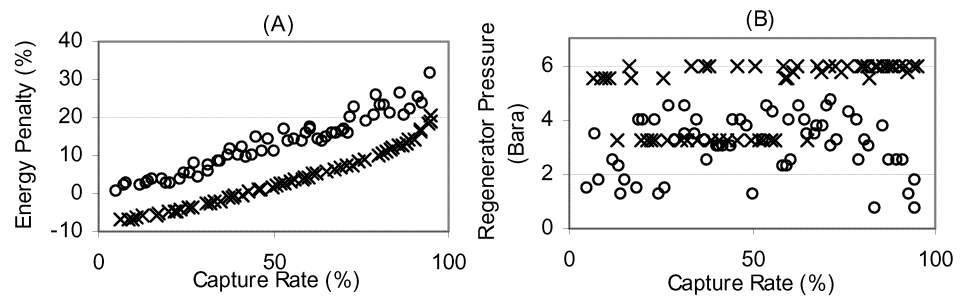


Figure 4: (A) Energy penalty for the optimised solutions for Opt. 1(x) & Opt. 2(o). (B) Regenerator pressure for the optimised solutions for Opt. 1(x) & Opt. 2(o).

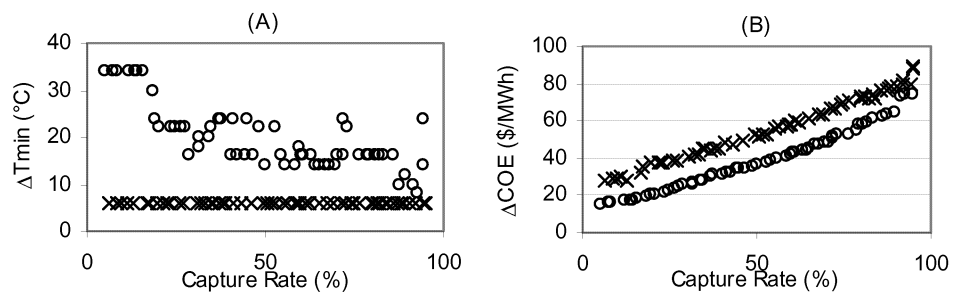


Figure 5: (A) The  $\Delta T_{min}$  for the optimised solutions for Opt. 1(x) & Opt. 2(o). (B) Pareto optimal solutions for the minimisation of  $\Delta COE$  and maximisation of capture rate optimisation (Opt. 2)(o) and the  $\Delta COE$  for the optimal solutions in Opt. 1(x).

## 4. Discussion

Figure 3A represents the maximum power that can be generated for the power station with the addition of CCS. As expected as the CO<sub>2</sub> capture rate increases the net power produced by the power station decreases. The optimised solutions provided in Figure 3A can be used to determine the cost of CCS (\$/t CO<sub>2</sub> avoided) when optimising for maximum power, shown by the “×” marks in Figure 3B. The cost of CCS decreases as the capture rate increases; this is due to the economies of scale of the CCS infrastructure. However, once the capture rate goes above 90-95 % the cost of capture begins to increase due to the increase in the rate of energy penalty caused by the increasing difficulty of capturing the remaining CO<sub>2</sub> in the flue gas. A plot of the energy penalty for the optimised solutions is given in Figure 4A. Interestingly when optimising for maximum net power, the energy penalty is negative for capture rates up to 40 %. The energy penalty is negative because there is considerable waste heat in the power station that can be used to provide the required heat and power for the new CCS infrastructure. The waste heat is available due to the low fuel costs relative to capital cost in the Victorian power sector which currently favours operating at lower than the maximum efficiencies. However, even with low or negative energy penalties at low capture rates, the cost of CCS still favours higher capture rates as shown by Figure 3B. When optimising for maximum net power, there are two distinct regenerator pressures (3.25 / 6 Bara) that are favoured (refer to Figure 4B). The temperature of the reboiler for those two regenerator pressures corresponds (including a  $\Delta T_{\min}$  of 6 °C) to the condensation temperature of two of the steam turbine extraction points. Therefore, if the pressure of the steam extracted from the turbine is different, then the corresponding optimal pressures are likely to be different. The  $\Delta T_{\min}$  of the heat exchanger network for all the optimised solutions that maximise the net power is (not surprisingly) at the lower bound of the variable (6 °C) (Figure 5A); however, that means the heat exchanger network costs are likely to be high.

The second optimisation problem minimises the  $\Delta\text{COE}$  whilst maximising the capture rate and the Pareto optimal solutions are represented by the “○” marks in Figure 5B. The  $\Delta\text{COE}$ , without any price on carbon, obviously increases as the capture rate increases. The  $\Delta\text{COE}$  for the optimised solutions from Opt. 1 are also shown on Figure 5B and for all capture rates the  $\Delta\text{COE}$  is greater than when the power station is optimised to minimise the  $\Delta\text{COE}$ . This suggests that maximising the net power from the power station in the Victorian context does not provide the most inexpensive power. The capital costs for the infrastructure to maximise the power generation, in particular the heat exchanger network, contribute to higher COE. The  $\Delta T_{\min}$  for the heat exchanger network when optimised to minimise the  $\Delta\text{COE}$  tends to values greater than the minimum, as shown in Figure 5A, ranging from 10 to 36 °C. The energy penalty is also close to 10 % higher for the solutions optimised to minimise the  $\Delta\text{COE}$  rather than maximise the net power. The cost of CCS is also cheaper for the solutions in the second optimisation problem due to the lower capital cost of the CCS infrastructure.

The regenerator pressure required for the optimisation to minimise the  $\Delta\text{COE}$  is very scattered (Figure 4B), suggesting that it has a second order impact on minimising the

$\Delta\text{COE}$  and that other variables that take on more consistent values after the optimisation (like  $\Delta T_{\min}$ ) are more important to minimise the  $\Delta\text{COE}$ . The addition of the CCS plant to the power station capturing 90 % of the flue gas  $\text{CO}_2$  without heat integration or optimisation had an energy penalty of 38 %, whereas the minimum energy penalty suggested by the first optimisation problem is only 14-16 %. To minimise the  $\Delta\text{COE}$  and consequently the cost of CCS, the optimum energy penalty is 22-25 %.

## 5. Conclusion

The combined heat integration and optimisation approach is a useful way of determining the estimated maximum net power generation possible from a power station with the addition of CCS and even more importantly the cost of CCS and the  $\Delta\text{COE}$ . The optimisation technique allows the designer to determine quickly what the optimum setting for a range of variables is to either maximise the net power or minimise the cost of electricity. The importance of heat integration is shown by large reductions (from 38 % down to 14 %) in the energy penalty possible in Victorian power stations when CCS infrastructure is retrofitted as a heat integrated system. However, due to the low cost of brown coal in the Victorian power sector and the resulting low variable cost, lower COE is delivered at energy penalties above the minimum.

## Acknowledgement

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