Delta Electricity PCC pilot plant relocation from Munmorah to Vales Point Power Station – Technical Report

Aaron Cottrell, Sanger Huang, Paul Feron

March 2016

Report to Coal Innovation NSW (CINSW)

Citation

Cottrell, A., Huang, S., Feron, P. (2016) Delta Electricity PCC pilot plant relocation from Munmorah to Vales Point Power Station – Technical Report

This report intended for public dissemination is derived from the following confidential client report: Cottrell, A., Huang, S., Feron, P. (2014) Delta Electricity PCC pilot plant relocation from Munmorah to Vales Point Power Station – Final Report – EP 147496

Copyright and disclaimer

Important disclaimer

Contents

Acknowledgments v

Executive summary vi

1 Overview of project 7

2 Background to the project 9

3 Process design 11
  - 3.1 Pressurised absorption 11
  - 3.2 Direct contact cooling condenser for stripper 14
  - 3.3 Multiple solvent/blended solvent flexibility 14
  - 3.4 Multiple feed streams for multiple projects 15

4 Engineering 16
  - 4.1 Existing equipment assessment 16
  - 4.2 New equipment and utility specifications 16
  - 4.3 Geotechnical survey 16
  - 4.4 Pilot plant layout 16
  - 4.5 Pilot Plant slab design 16

5 Process, safety and risk analysis 17
  - 5.1 Site Access, Permitting, and Approvals 17
  - 5.2 Construction 17
  - 5.3 Commissioning 17
  - 5.4 Risk analysis 17

6 Equipment delivery and supply of services 18
  - 6.1 Flue gas compressor, blower and support structure 18
  - 6.2 Carbon adsorption pilot plant 19
  - 6.3 Column Packing and Internals 20
  - 6.4 Steam Boiler 20
  - 6.5 High Voltage power supply 21
  - 6.6 Low voltage power supply 22
  - 6.7 Absorber insulation 22

7 Pilot plant relocation 24
  - 7.1 Pipework documentation 24
  - 7.2 Site layout at Vales Point 24
  - 7.3 Physical plant movements 24
  - 7.4 Interconnect between pilot plant and Vales Point Power Station 24
  - 7.5 Site preparation at Vales Point power station 24
  - 7.6 Dismantling of pilot plant at Munmorah 29
  - 7.7 Pilot plant installation at Vales Point 33

8 Commissioning and final preparations 43
  - 8.1 Control and instrumentation system 43

- 8.2 Mechanical 43
- 8.3 Electrical 44
- 8.4 Solar thermal project/UNSW membrane project 44

9 Lessons learnt, conclusions and recommendations 45

- 9.1 Lessons learnt 45
- 9.2 Conclusions 45
- 9.3 Recommendations 45

10 References 46

Appendix A Plant Lay-out 47

Appendix B Project abstract 48

Figures

Figure 1 Location of pilot plant at Vales Point power station 8

Figure 2 Aspen Plus process simulation for pressurised absorption process 13

Figure 3 Blower for flue gas 18

Figure 4 Compressor for pressurised absorption 19

Figure 5 Carbon adsorption plant installed on site 20

Figure 6 Electric boiler installed 21

Figure 7 Absorbers with insulating ceramic paint 23

Figure 8 Excavation hampered by old concrete 25

Figure 9 Forming up structure slab base and positioning of hold down bolts 25

Figure 10 Structure slab pour and finish 26

Figure 11 Preparation for main slab 26

Figure 12 Slab and structure earthing straps 27

Figure 13 Forming up and setting reinforcement for main slab 27

Figure 14 Main slab poured and finishing 28

Figure 15 Pour of bund walls 28

Figure 16 Slab complete 29

Figure 17 Pipework removed from the pilot plant 30

Figure 18 Disconnected ancillary equipment 30

Figure 19 Removal of absorber column for installation of new packing and insulation treatment 31

Figure 20 Dismantling of pilot plant 32

Figure 21 Pilot plant after dismantling 32

Figure 22 Pipework showing weld corrosion damage 33

Figure 23 Main pilot plant structure re-assembled with insulated absorber columns in place 34

Figure 24 Inlet pipework from the flue gas duct (not connected) 34

Figure 25 Overall view of plant showing additional pipework, cable trays and high voltage supply shed.35

Figure 26 Closer view showing new blower platform, with blower and new compressor in position. 35

Figure 27 Chemical storage positioned 36

Figure 28 Blower and electrical control cabinet on top of new platform. Compressor below 36

Figure 29 New pipework for blower and flue gas compressor 37

Figure 30 Pipework for connection of solid sorbent rig 37

Figure 31 Boiler and chilling unit located in front of solid adsorbent unit 38

Figure 32 Pipework and cable trays 38

Figure 33 Many runs of hard piping replacing previous flexible hose. 39

Figure 34 Installation of pipework and new control valve from after cooling heat exchanger 39

Figure 35 Installation of compressor and blower pipework and supports 40

Figure 36 Completed connection to solid sorbent rig and additional electrical and small pipework in the background ... 41

Figure 37 Side view of pilot plant – May 2014 ... 41

Figure 38 Front view pilot plant – May 2014 ... 42

Acknowledgments

This project was carried out within CSIRO Energy and received funding from the New South Wales Government through the Coal Innovation NSW Fund. We gratefully acknowledge the support from Delta Electricity.

Executive summary

This project aimed to enable further development of a process, based on aqueous ammonia and possibly other solvents, for post-combustion capture of carbon dioxide from power station flue gases for application in New South Wales in preparation of a larger scale demonstration of the technology. The project involved relocating the PCC pilot plant facility from Munmorah power station to Vales Point power station. At Vales Point the pilot plant has undergone further refurbishment to enable its effective operation.

Relocation of the Delta Electricity PCC pilot plant from Munmorah Power Station to Vales Point was necessary as the availability of flue gas had ceased at Munmorah Power Station due to its closure and connection to power station flue gas is essential for the experimental programme. The relocation involved the provision of new flue gas off-take points, civil works for the new pilot plant site, removal and re-installation of the PCC pilot plant on the new site and preparation for connection to local infrastructure (electricity, ICT, water).

The pilot plant was also refurbished utilising the insights gathered from the pilot plant program carried out at Munmorah power station. The refurbishment included the following:

- Replacement of dumped packing with structured packing material to improve the CO_2 capture performance
- Installation of additional column sections to increase the ammonia recovery
- Installation of column lagging to enable operation at lower temperatures
- Provisions to allow continuous long-term operation of the pilot plant
- Refurbishment of the existing blower
- Replacement of boiler.

The pilot plant has been commissioned on air and water and has been modified in preparation for an integrated solar thermal trial which aims to realise the benefits of utilising renewable energy for regeneration of capture solvents to lessen the impact on the power station.

The project has also supported two other research projects. One of these was a CSIRO project supported by Coal Innovation NSW investigating the capture of CO_2 using solid adsorbents and the other being with the University of NSW funded by ANLEC R&D/CO2CRC investigating the use of membranes for CO_2 capture. Separately a project funded by ARENA aimed at the demonstration of solar thermal energy for regeneration of the liquid absorbents was started up. This involved the first use of the pilot plant in a research project.

The project has enabled the consolidation and extension of a technical infrastructure for the evaluation of post-combustion CO_2 capture (PCC) technologies for application in coal fired power plants in New South Wales. The PCC pilot plant at Vales Point is unique in that it is the only facility in New South Wales that can actually evaluate technologies utilising real flue gases from coal combustion. It is recommended that this infrastructure is utilised to address issues that are pertinent to the development and deployment of environmentally benign and cost-effective post-combustion capture technologies.

As already demonstrated via a number of parallel projects the infrastructure can also be used to evaluate alternative capture technologies under realistic conditions and these options should be pursued as well.

The recommendations stemming from this project will need to be considered in light of the potential for setting up a complete and viable CO_2 capture and storage chain in New South Wales.

1 Overview of project

CSIRO has been collaborating with Delta Electricity on researching the use of aqueous ammonia as the liquid absorbent in a Post-Combustion Capture (PCC) pilot plant, supported by the Australian Commonwealth through the Asia-Pacific Partnership on Clean Development and Climate (APP). As part of this collaboration, CSIRO and Delta Electricity jointly designed and constructed the PCC pilot plant which was originally located at Munmorah power station in 2008. This $5M pilot plant, owned by Delta Electricity, was used for a series of research campaigns during 2009 and 2010 in which the technical operational characteristics of an aqueous ammonia process were established.

The initial project proposal to the then New South Wales Clean Coal Fund entitled "Preparing for deployment of post-combustion capture of CO_2 in the New South Wales power sector" was submitted in 2009. In response to the feed-back from the Clean Coal Council secretariat a revised proposal was submitted in 2010 under the new title "Further development of an aqueous ammonia process for post-combustion capture of CO_2 in the New South Wales power sector". A project agreement was executed in February 2011 with the following aim:

> ***To relocate the Delta Electricity Post Combustion Capture Pilot Plant from Munmorah Power Station to Vales Point Power Station and refurbish it to allow further development of the aqueous ammonia PCC process for application in New South Wales.***

This project involved relocating the PCC pilot plant facility from Munmorah power station to Vales Point power station and refurbishing the pilot plant at Vales Point to enable its effective operation, not only for the development of an aqueous ammonia based process, but also for other amine-based PCC processes.
Relocation of the Delta Electricity PCC pilot plant from Munmorah Power Station to Vales Point was necessary to increase the availability of flue gas which is required for the experimental programme.

The relocation involved the provision of new flue gas off-take points, civil works for the new pilot plant site, removal and re-installation of the pilot plant on the new site and preparation for connection to local infrastructure (electricity, ICT, water).

The pilot plant was refurbished utilising the insights gathered from the pilot plant program carried out at Munmorah power station and from other pilot plant programs in which CSIRO was involved. The refurbishment included the following:

- Replacement of dumped packing with structured packing material to improve the CO_2 capture performance
- Installation of additional column sections to increase the ammonia recovery
- Installation of column lagging to enable operation at lower temperatures
- Provisions to allow continuous long-term operation of the pilot plant
- Refurbishment of the existing blower
- Replacement of boiler.

CSIRO has also installed an adsorbent-based rig (including adsorbers, mini flue gas treatment column, associated pumps, fans, heat exchangers, controls, instrumentation, pipework and structural support) alongside the pilot plant during its refurbishment. This rig will remain in CSIRO ownership and does not form part of the PCC pilot plant owned by Delta Electricity. The work related to this rig was also supported by Coal Innovation New South Wales under a separate funding agreement.

The relocated pilot plant at Vales Point is now situated within the area of the Unit 5/6 stack and post bag-house ductwork as shown in the Figure 1.

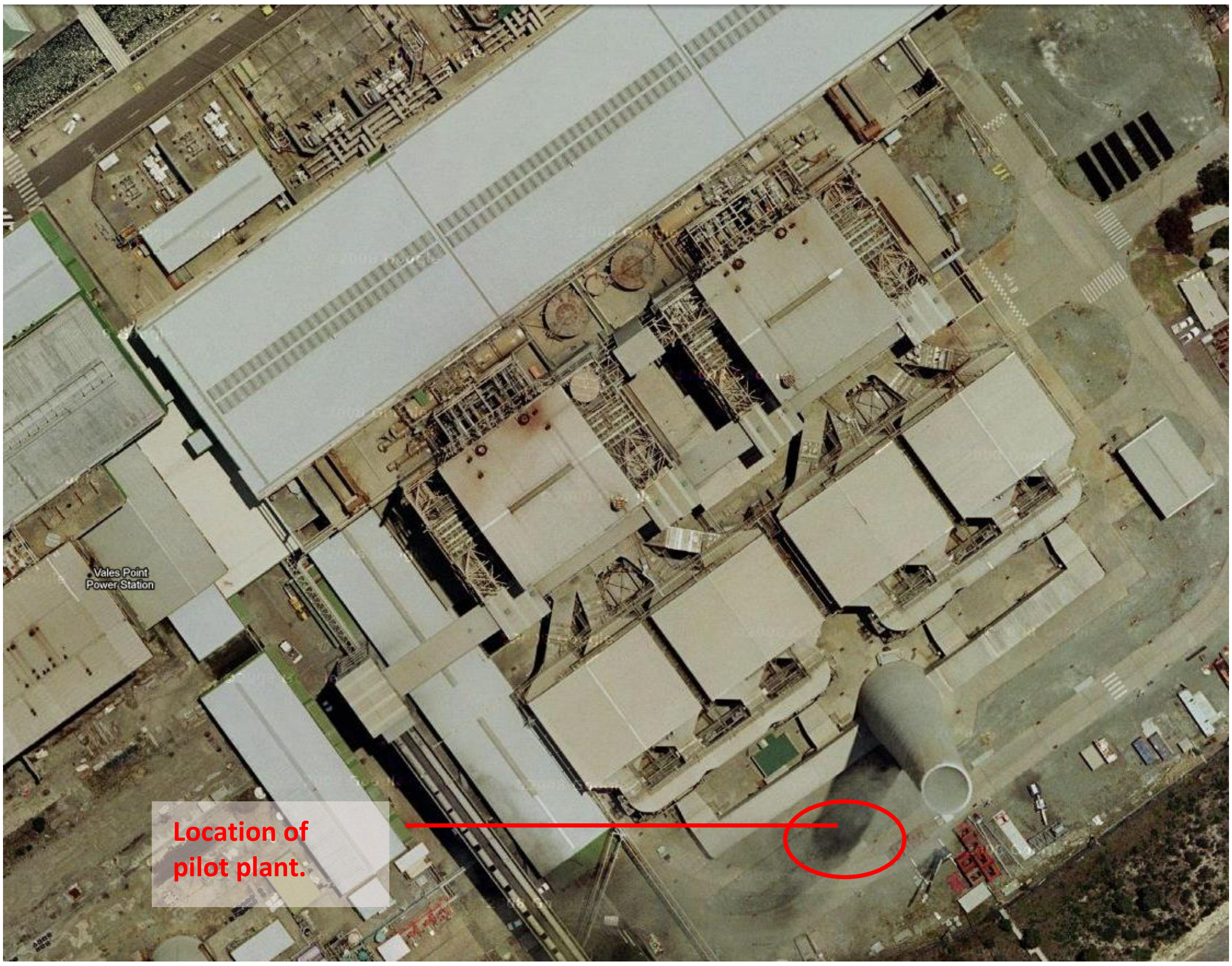


Figure 1 Location of pilot plant at Vales Point power station

After a brief introduction to the background of the project in chapter 2, the approaches to the process design, engineering and risk and safety are discussed in chapters 3, 4 and 5, respectively. This is then followed by a description of the various pieces of new equipment delivered to the pilot plant (chapter 6), the actual pilot plant relocation activities (chapter 7) and the commissioning work (chapter 8). The final chapter deals with lessons learnt, conclusions and recommendations (chapter 9).

2 Background to the project

A post-combustion capture technology development and demonstration program, based on an improved/novel solvent process with potential to substantially minimise the adverse impact of PCC is currently underway by CSIRO and a number of partners. Over the past 7 years CSIRO has developed an extensive science capability in post-combustion capture processes based on reactive liquid absorbents. The bulk of this activity is at the CSIRO Energy Centre in Newcastle, where facilities are available for the characterisation of relevant properties of liquid absorbents proposed for CO_2 capture, as well as the characterisation of the overall process performance. This includes laboratory based set-ups for absorbent screening, measurement of absorption rates, vapour-liquid equilibrium determination and absorbent degradation. In addition to the lab-based capability, state-of-the-art process and plant modelling tools are available to perform process validation and optimisation studies of fully integrated PCC plants including the economic analysis of such plants.

Furthermore CSIRO has combined and integrated the PCC research program with a PCC pilot plant programme with test facilities established in the three eastern states in Australia. The overall PCC R&D programme represents an investment of $30M across CSIRO in conjunction with the power sector. It has been largely supported by the Australian federal government through the Asia Pacific Partnership on Clean Development and Climate. The results from the programme [1] have demonstrated that:

- PCC using liquid absorbent based technology is a viable option to capture CO_2 from flue gases from coal fired power plants in Australia.
- The costs for PCC are between $60 and $110 per tonne CO_2 avoided for the standard liquid absorbent, with a sizeable scope for reduction of these costs.
- Cost reductions can be achieved by a further focus on reduction of the capital costs and to a lesser extent on the reduction of the energy penalty.
- The flue gas quality of Australian power plants is such that FGD and possibly DeNOx needs to be installed to enable commercially available PCC processes.
- The nature and extent of the environmental impacts resulting from PCC processes are not well understood and require further investigation.

In New South Wales, CSIRO is collaborating with Delta Electricity and the pilot plant focus has been on the use of aqueous ammonia as the liquid absorbent. CSIRO and Delta Electricity have jointly designed and constructed the PCC pilot plant which was located at Munmorah power station. This $5M facility was previously used for a series of campaigns in which the technical operational characteristics of an aqueous ammonia process were established. That program of campaigns was finalised in July 2010. The choice for aqueous ammonia was based on the following considerations:

- Ammonia is a robust and cheap liquid absorbent, not subject to degradation like other amines,
- A process based on aqueous ammonia can capture several pollutants in a single process, which is beneficial and provides an opportunity for cost reductions
- There is a potential for lower energy requirements because of the low binding energy and higher loadings and the ability to provide a CO_2-product at elevated pressure.

The results from the research program have been presented in a number of scientific publications [3-5]. The operational experience with the aqueous ammonia pilot plant has confirmed its benefits, but also revealed further challenges:

- The ammonia losses, as a result of its high volatility, can be substantial depending on the operating conditions and this necessitates the installation of a comprehensive gas washing system and operation at low temperature,
- The CO_2 absorption rates are low, which will result in much larger absorbers compared to the standard amine processes and hence higher investment costs,
- Operating the desorber similar to regular amine processes will result in the formation of ammonium-bicarbonate solids, which will block the condenser,
- The requirement for cooling in an aqueous ammonia process is quite high, which results in a sizeable additional energy requirement, particularly when applied in Australia.

This project aims to extend the life of the pilot plant to enable continued research to take place in the future to allow the challenges to be addressed. This was done by relocating the plant from its previous location at the Delta Electricity owned Munmorah Power Station, which has been shut down, to the Vales Point Power Station, also owned by Delta Electricity, located a few kilometres away.

3 Process design

CSIRO scientists and engineers developed a number of concepts to address particular issues within the previous pilot plant arrangement. The first stage of the project was for CSIRO to assess these concepts and to integrate them into the pilot plant design by developing different process flow-sheets and evaluating these using process modelling. The process flow-sheets and associated process modelling aided in determining both the suitability of existing equipment and specifications for the new equipment that needed to be purchased, as described in the following sections.

3.1 Pressurised absorption

CSIRO has patented a PCC process concept where the cooling requirement for an aqueous ammonia-based process is provided by expansion of the flue gas after pressurisation and CO_2-absorption [2]. This allows for a simpler and potentially cheaper capture process compared to other aqueous ammonia processes, currently under development. The process flow sheet as derived from process modelling in Aspen Plus is shown in Figure 2.

The anticipated benefits for pressurised absorption are that:

- The absorber can be reduced in size
- It has higher CO_2-absorption rates
- The ammonia losses can be decreased
- It can be operated at higher temperature i.e. chilling might not be required.

The key trade-off in this approach is with the implementation of a flue gas compressor which comes with increased capital and operating costs over the standard process.

On initial development of this aspect of the project it was found that a pressurised absorption system would indeed allow for significant benefits in the operation as mentioned above. An additional change of scope, i.e. to recover the waste pressure energy in terms of motive power rather than cooling energy led to some interesting plant design change suggestions. Preliminary costing calculations and quoting found that compression and expansion would have a significant impact on capital cost for both the pilot plant and at larger scale. Further investigation revealed that some newly available compressor and expander technology (www.ramgen.com) could significantly reduce these costs at larger scale and offer additional benefits. Unfortunately this technology was found to be unsuited to the pilot scale of our process and as a result a more standard compressor was chosen.

To enable a full understanding of the performance of the process and limit interactions with oils of a standard oil flooded/lubricated compressor with the rest of the process, we elected to search for a compressor of an oil-free variety. After investigating many compressor suppliers we found that either the suppliers could not quote on a machine of this type or it would come at high cost with limited or no warranties.

Further investigations into a suitable compressor resulted in CAPS Australia providing the most suitable solution. It should be noted that all the suppliers were hesitant to supply a compressor to this situation and if they did agree it would be on the condition that there be no warranty associated with its operation.

An order was placed for the compressor with CAPS Australia for $205,000 which did not include a warranty due to the nature of the gas that it was compressing. Discussions were held with Delta Electricity and it was decided that this was an acceptable risk as operational and maintenance procedures could be used to minimise the chance of damage/degradation of the compressor.

The plant would still have a secondary blower capable of running the plant at near-ambient pressure. This would allow for the compressor to only be used as required.

In the previous pilot plant design ammonia collected in the wash section above the absorber was effectively utilised to react with SO_2 and NO_2 in a pre-treatment column before the absorber. With the compressor now driving the gas flow it was deemed necessary to move the compressor from a location before the pre-treatment column to a location after the pre-treatment column. This was for a number of reasons:

- A compressor produces a significant amount of low grade waste heat and must have a cooled feed to work efficiently,
- Corrosive gases in the flue gas will aggressively attack compressor components unless expensive components are purchased,
- Compressors do not tolerate dust well.

Originally the process plant incorporated a wash section after the CO_2 absorber integrated with the flue gas pre-treatment for combined emission control of ammonia, NO_2 and SO_2. The separate liquid loop, connecting the pre-treatment column with the wash system, was shown to be effective in removing SO_2 and NO_2 prior to the CO_2-absorber, using ammonia from the wash section but also effective in removing NH_3 after the CO_2 absorber, using the dissolved acid gases (SO_2 and NO_2) from the flue gas pre-treatment [3]. Process modelling results indicated that this design in conjunction with the pressurised absorber operation would result in precipitation in and after the flue gas compressor. More precisely, any ammonia vapour slipping from the pre-treatment column would pass through the compressor where it would condense with water on the intercoolers and after-coolers, forming a precipitate as ammonium bicarbonate on the heat exchanger surfaces which would cause blockages. This was expected to significantly hamper normal operation. Although SO_2 and NO_2 removal can be easily achieved by the commonly used alkaline pre-treatment of the flue gas, the alkaline nature of the solution containing the recovered acid gases would prevent this solution from being used for ammonia emission control. An alternative design was proposed, avoiding the presence of NH_3 at the compressor inlet, while still making use of the acid gases recovered for ammonia emission control. An acid based flue gas pre-treatment in conjunction with an oxidation reaction could reduce SO_2, NO_2 and even NO while at the same time reducing ammonia in the waste flue gas to less than 50 ppm using the acids recovered in the flue gas pre-treatment. Optimisation of this system would be required to minimise ammonia loss and chemical reagent use. Overall it was expected that the new emission control process would result in a very workable pressurised aqueous ammonia based CO_2 capture. The new system requires some additional chemical reagents that increase the operating cost of the plant with the benefit of a higher quality by-product from the flue gas pre-treatment. The effectiveness of this novel pre-treatment design will need to be investigated experimentally in ensuing projects.

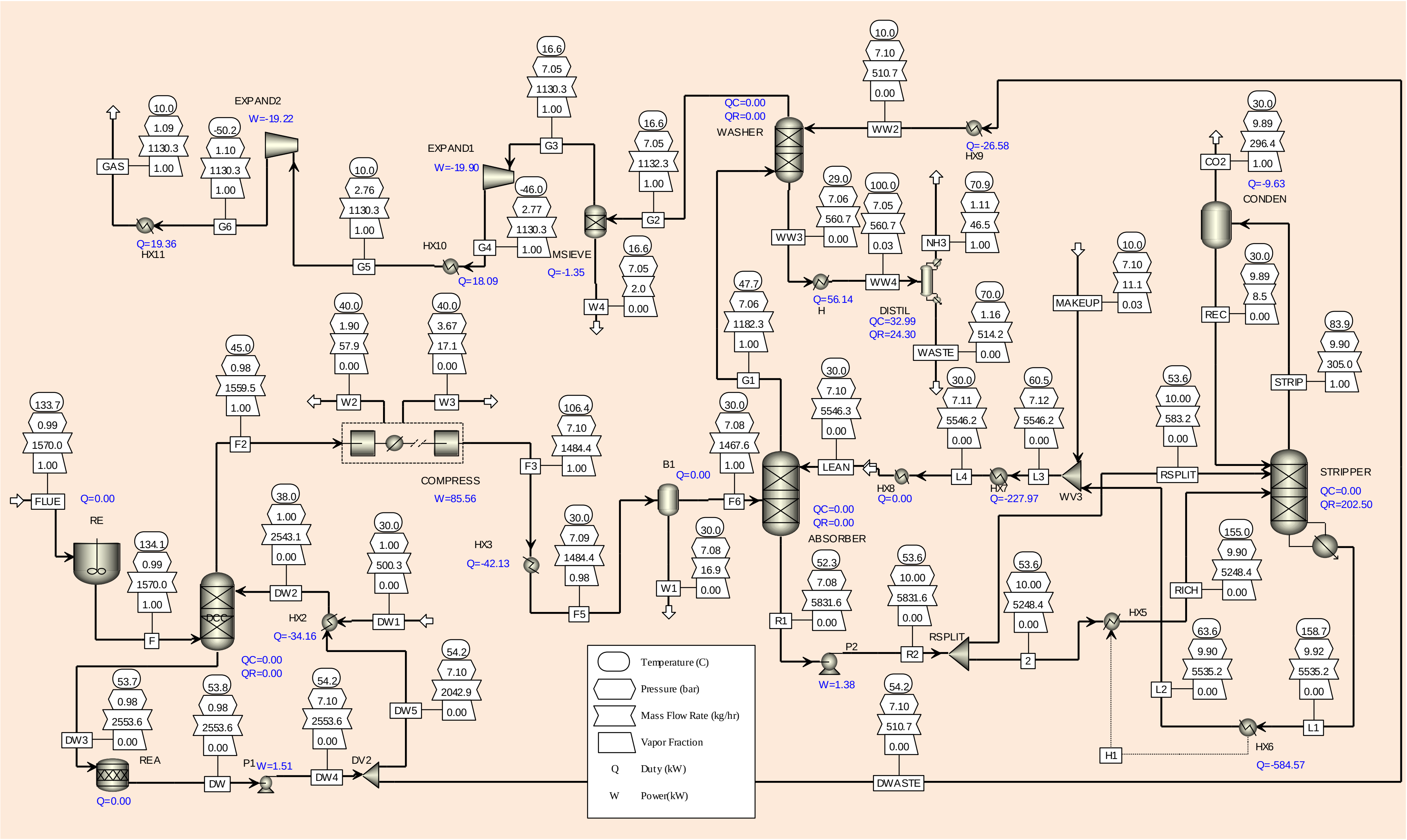


Figure 2 Aspen Plus process simulation for pressurised absorption process

3.2 Direct contact cooling condenser for stripper

A major operational difficulty with the plant in its previous configuration using aqueous ammonia was a consistent issue of precipitation of ammonium bicarbonate in the heat exchanger used as a condenser in the vapour stream from the top of the stripper. To address this concern it was proposed to incorporate a direct contact type cooling condenser. The exiting heat exchanger would be used to provide the cooling for the wash liquid used. The key trade off to this is additional equipment cost but provides some key benefits:

- Increased operational availability
- Better control of CO_2 product quality
- More efficient cooling
- Creation of another stream with flexibility to be used in other areas of the plant such as pre-treatment.

When investigating the practical aspects of this modification and the space limitations of the pilot plant it was decided that this modification could not be implemented. The required plant modifications needed to be quite close to the stripper outlet to be effective and this was considered to be impossible within the space available in the upper part of the plant framework. Instead further modelling was conducted to investigate other ways to minimise possible precipitation issues.

A number of different process concepts has been modelled to resolve this particular problem. It was shown that to a large extent the problem of ammonium bicarbonate precipitation could be reduced by having a part of the cold rich solvent from the base of the absorber pumped directly to the top of the stripper. This, so-called rich-split process modification creates a greater temperature gradient in the column and reduces the amount of ammonia going into the condenser area of the stripper. However, when evaluating a number of different operational parameters it was shown that some formation of precipitates was still possible under certain operating conditions [5]. These operating conditions may be unavoidable at different points in the operational envelope and will therefore require careful operation to avoid precipitate formation.

3.3 Multiple solvent/blended solvent flexibility

As the pilot plant was designed for use with ammonia only it had some inflexibility when it comes to trialling other solvents. In order to allow the plant to achieve more outcomes and produce direct comparisons to other solvents the pilot plant has been modified to increase plant flexibility so that other solvents or ammonia blends can be operated effectively.

To increase flexibility in the plant several pipework modifications have been implemented to allow for multiple solvent use in the pilot plant. Key process changes included a reconfiguration of the wash system circuit where originally captured ammonia from the absorber wash tower was used to remove SO_2 and NO_2 in the pre-treatment circuit. This is not an appropriate system for amine solvents as amine losses need to be avoided because amine solvents are not as cheap as ammonia. Another key process change was in the operation of the stripper. Previously the lean solvent flow was driven by pressure developed in the stripping column. With amine solvents generally operating at lower pressures it was required to change the solvent delivery scheme so that solvent can be effectively pumped to the absorber.

In delivering these modifications some difficulties were encountered as space was restricted in areas of the pilot plant which required alternate piping routes or longer construction times working in restricted space.

3.4 Multiple feed streams for multiple projects

The relocation of the pilot plant has also overseen the incorporation of other projects which utilised the slip stream feed from the power station. The needs for two other projects have been addressed and this project has facilitated the completion of those projects within the pilot plant site. The two other projects are:

- Site trials of carbon based solid sorbents (CSIRO - Dr. Su Shi, funded by Coal Innovation NSW)
- Membrane testing (UNSW – Prof. Vicky Chen funded by ANLECR&D through CO2CRC)

4 Engineering

4.1 Existing equipment assessment

The existing pilot plant equipment was checked and catalogued to ensure that it was in a good state of repair. Many components were found to be in poor state of repair due to corrosion and other deterioration as there had been a lack of maintenance on the plant since it was shut down. Major items requiring repair were the boiler, the existing blower, the compressed air system, numerous instruments and control equipment, electrical cabinets, pumps, pipes and hose-work.

4.2 New equipment and utility specifications

All new equipment was sized to suit its application in the PCC pilot plant resulting in the equipment specification needed for quoting and procurement. Connection requirements into the utilities that Delta Electricity would be providing were also specified to prepare contractors for quoting.

4.3 Geotechnical survey

A geotechnical survey was carried out to determine the bearing capacities of the earth at the proposed site of the pilot plant. This also incorporated a number of steps to determine whether there were any existing underground services at that site. Delta Electricity was required to search its construction records as well as conduct underground service detection around the site. All of this information was used to develop an engineered slab design suitable to support the pilot plant structure.

CSIRO enlisted the services of RCA Australia to perform a number of drill tests on the location that the pilot plant would be situated. The tests showed that the area had adequate bearing capacity (no piers required) and that there appeared to be a sandstone substrate beneath the surface. It was not until after excavation for the slab started that it became apparent that the substrate was indeed concrete from an old spoil and wash down pile.

4.4 Pilot plant layout

As the new site was different to the existing site the layout had to be rearranged to suit the shape of the site as well as the accessible services. This was done in such a way that the process was not affected by the layout. The pilot plant layout was fed into the slab design and allowed for position of the main mass for the support of the columns. The rest of the layout was designed to try and allow for ease of access and maintenance as much as possible but even with this we found that it still became crowded during the assembly. A copy of the plant layout is shown in Appendix A.

4.5 Pilot Plant slab design

Using the information from the geotechnical study the slab design was completed by Worley Parsons. This process took a number of iterations as the excavation process found covered manholes and other objects in the area that needed to be avoided.

5 Process, safety and risk analysis

5.1 Site Access, Permitting, and Approvals

It was necessary to engage with a number of contractors to perform the project. These needed to have access to the site to perform their work. Site access was granted by completing the appropriate inductions, followed by the handing out of site access cards enabling the use of general site facilities such as toilets, washrooms etc.

For some aspects of the project Delta Electricity needed to provide appropriate permits and approvals for work to be carried out onsite. Contractors were required to provide Safe Work Procedures so that they could obtain permits to work.

A general environmental risk analysis (called REF – Review of Environmental Factors) for the overall Project was prepared by Delta Electricity before the plant could be operated. Permission to perform work on the Vales Point site was given to CSIRO in April 2012.

5.2 Construction

All construction services have been performed by contractors to CSIRO. CSIRO has been responsible for the management of these contractors throughout the project.

The first step in construction of the slab was excavation. The excavation process uncovered a number of issues which required some additional engineering design activities. The new design needed to account for underground services that were uncovered and could not withstand the load of the existing slab design. There was also an additional issue associated with reported underlying sandstone being confirmed as aged concrete. The aged concrete proved to be very hard and required additional time for removal. Larger equipment was not used to reduce the risk of damage to nearby services.

The contractors (Lawcon) worked well with CSIRO and Delta Electricity and provided a slab to specifications although some issues arose later that has caused concern due to the level of vibration onsite. Due to the vibrations the concrete bund developed cracks which propagated almost the entire way around the bund wall and with a full penetration of the wall. It is most likely that these cracks had developed due to the heavy vibrational loads in the vicinity of the flue gas ducting. These cracks required repair to ensure the bund was fully sealed.

5.3 Commissioning

At the completion of the construction phase CSIRO evaluated the plant for operability by performing a number of commissioning activities. These activities are described in Chapter 8. No solvents or chemicals were allowed to enter the pilot plant system until CSIRO had adequately proven that the process plant was in good working order.

5.4 Risk analysis

With all the changes required to the existing design it was deemed necessary to revisit the original HAZOP and the safety and risk assessments that have been carried out previously.

6 Equipment delivery and supply of services

6.1 Flue gas compressor, blower and support structure

A support structure was designed to better position both the blower (operation at atmospheric pressure) and compressor (pressurised absorption) on the same side of the plant. The structure was designed and rated to hold the blower and was subsequently constructed and installed. The blower was installed on top of the structure and the flue gas pipework was connected.

The flue gas compressor was installed below the structure but it needed modification by the supplier to cater for the plants connections. A heat recovery heat exchanger was installed after the compressor to enable recovery of thermal energy from the compressed flue gas. Figures 3 and 4 show the blower and the compressor, respectively.

Figure 3 Blower for flue gas

Figure 4 Compressor for pressurised absorption

6.2 Carbon adsorption pilot plant

The solid adsorbent pilot plant was installed and connected to power and water. Initially the unit was commissioned on bottled CO_2, awaiting final pipework connection and risk assessment before flue gas could be introduced to the plant in January 2013. Figure 5 shows the carbon adsorption pilot plant.

Figure 5 Carbon adsorption plant installed on site

6.3 Column Packing and Internals

The column packing materials used at the Munmorah PCC pilot plant were based on random packing (Pall rings) with the internals based on an in-house design. It was decided to change over to industry standard structured packing materials and internals. Sulzer Chemtech was approached for a suitable overall column design for the Vales Point PCC pilot plant utilising the existing column dimensions. This was a complex task for a plant that needed to be designed for flexibility for multiple solvents with varying reactant concentrations, viscosities, operating temperatures and pressures, and reaction kinetics while at the same time working within the constraints of the existing column arrangement. In discussions with Sulzer Chemtech the column design was manipulated in a number of different configurations using a 30% mono-ethanolamine solution and aqueous ammonia solutions and a workable design was established. The columns were dismantled, and removed from the plant, delivered to an external fabrication contractor where they were disassembled and the old packing materials and internals removed. The columns were then modified and re-assembled with the new structured packing materials and internals in place.

6.4 Steam Boiler

A new steam boiler, needed for the regeneration of the liquid absorbents, was purchased and arrived on site in March 2012 (Figure 6). This replaced the old boiler which exhibited several leaks and some of the heating elements resulted in short-circuits. Replacement was considered to be more cost-effective than ongoing maintenance and repair of the old boiler.

Figure 6 Electric boiler installed

6.5 High Voltage power supply

Bringing a suitable power supply to the pilot plant was not trivial and required significant forethought and planning to get right and maintain low cost. There was a number of supply options but ultimately we were limited to two as long line runs from other areas of the power station would be too expensive. The two options were:

- Option 1 - using the 690 11kV feeder supply (needs poles, HV wires, underbore of roadway, utilising existing 11kV/415V transformer) but this would be an off-site supply and currently owned by Ausgrid.
- Option 2 - using the 3.3kV station services board (needs more design work, more electrical devices for compatibility, long cable runs, and new 3.3kV/415 transformer). This was the most expensive option but could be done within the bounds of Delta Electricity site.

Ultimately we were able to proceed with option 1. Engineering was complete in October 2012 and the High Voltage power supply was completed in January 2013

6.6 Low voltage power supply

With the high voltage power supply completed the low voltage power supply and data cabling was subsequently tackled. New cable trays and supports have been put in place ready with new cables run through them. Some electrical isolation boxes were found to be corroded beyond repair and needed to be replaced. Rather than a powder coated metal case a plastic case was used. Due to the rearrangement of equipment to suit the new site new cabling needed to be installed. The electrical connections were completed in April 2013.

6.7 Absorber insulation

One of the drawbacks of the plant from its original operation was its lack of insulation on the absorber columns to minimise cooling loss from the chilled ammonia solvent. This in itself prevented the plant from being operating at the preferred temperatures to minimise ammonia slip. When the absorbers were removed from the plant to have new packing installed and reassembled, the columns were then painted with a number of layers of ceramic paint called Mascoat. This paint has been designed to act as an insulating layer limiting heat transfer from the walls of the absorber and allowing the plant to operate at preferred temperatures with less difficulty. This work was completed in October 2012. Figure 7 shows the absorber columns with the distinctive blue insulating ceramic paint.

Figure 7 Absorbers with insulating ceramic paint

7 Pilot plant relocation

7.1 Pipework documentation

In constructing the pilot plant at the Munmorah site some pipework was built on site and not well documented. In order to effectively relocate the plant and understand the future piping requirements an updated set of pipework documents needed to be prepared. The pipework was documented and the information passed on to potential contractors to quote on disassembly/reassembly.

7.2 Site layout at Vales Point

The usable area on site at Vales Point was determined resulting in the establishment of the new site layout for the plant. Constraints were imposed by the lack of some of the pipework documentation, the final blower/compressor specifications and the initially unknown positioning of the other two projects' facilities.

7.3 Physical plant movements

Mechanical disassembly of the PCC pilot plant did not take place until the Vales Point site was ready to receive the pilot plant from Munmorah power plant. A storage container for the intermediate storage of sensitive items was purchased and placed onsite at Munmorah in May 2011.

No site work could take place at the Vales Point site until the Review of Environmental Factors (REF) received signoff from both the Office of Environment and Health (OEH) and Delta Electricity. This process was finalised in March 2012.

7.4 Interconnect between pilot plant and Vales Point Power Station

Specifications for the pipework connection to the Vales Point Power Station were established and sent to Delta Electricity for review and approval. The pipework connection could only be installed during a period of downtime of the respective power station unit (May 2011).

7.5 Site preparation at Vales Point power station

An order was placed with Stelform for the relocation of the plant and equipment. Slab construction took place in May and June of 2012. Figures 8 to 16 give an overview of the excavation and slab construction activities.

Figure 8 Excavation hampered by old concrete

Figure 9 Forming up structure slab base and positioning of hold down bolts

Figure 10 Structure slab pour and finish

Figure 11 Preparation for main slab

Figure 12 Slab and structure earthing straps

Figure 13 Forming up and setting reinforcement for main slab

Figure 14 Main slab poured and finishing

Figure 15 Pour of bund walls

Figure 16 Slab complete

When the pilot plant was lifted into position it was found that many of the hold down bolts did not line up with the plant's base frame. This meant that the hold down bolts needed to be removed to stand the frame. With many of the hold down points removed an engineered solution was required to ensure that we could effectively secure the plant to the slab and avoid any overturning load. Worley Parsons who prepared the slab design were approached to design solutions to rectify this issue. Two options were discussed:

- Option 1 – With the plant in its current position weld new base plates to the corners of the plant to spread the load and give room for new anchor points to be drilled and secured to the slab.
- Option 2 – relocate the plant off centre by 50mm in both orthogonal directions and redrill and chemset with appropriate threaded bar and chemset material.

After further discussion option 2 was chosen for ease of work without having to modify the structure which would also require re-engineering. This process resulted in additional work in resecuring the plant. With the plant relocated and secured it was refitted with the two absorbers and some of the internal gas pipework.

7.6 Dismantling of pilot plant at Munmorah

The pilot plant was disassembled and removed in July and August of 2012 at which point it was transferred to Vales Point power station. The columns were removed and sent off-site to be fitted with new structured packing provided by Sulzer, which arrived in June 2012 and insulated with the Mascoat blue ceramic insulating paint. Figures 17 to 22 show various stages of the relocation process. Subsequently the columns were reassembled and reinstalled back into the plant (December 2012).

Figure 17 Pipework removed from the pilot plant

Figure 18 Disconnected ancillary equipment

Figure 19 Removal of absorber column for installation of new packing and insulation treatment

Figure 20 Dismantling of pilot plant

Figure 21 Pilot plant after dismantling

Figure 22 Pipework showing weld corrosion damage

7.7 Pilot plant installation at Vales Point

The initial installation occurred in September and October of 2012 with the main items laid out on the pad. The original stairs shown in Figure 23 were scrapped to make way for a support platform for the blower as the limited space on the pad did not allow for this.

Figure 23 Main pilot plant structure re-assembled with insulated absorber columns in place

Figure 24 Inlet pipework from the flue gas duct (not connected)

The plant has undergone a significant amount of renewal of and modification to its pipework to cater to the new site layout and site requirements. Figures 25-36 give an overview of the progress made through-out the ensuing project phase. The original project plan did not contain an allowance for installation of welded pipe where flexible hose had been previously used. Due to safety concerns associated with higher pressure operation and the utilisation of other solvents it was decided that it would be best to use hard piping where possible. The incorporation of this hard piping into the plant was difficult because of the tight lay-out of the plant with many bends and welds required.

Figure 25 Overall view of plant showing additional pipework, cable trays and high voltage supply shed.

Figure 26 Closer view showing new blower platform, with blower and new compressor in position.

Figure 27 Chemical storage positioned

Figure 28 Blower and electrical control cabinet on top of new platform. Compressor below

Figure 29 New pipework for blower and flue gas compressor

Figure 30 Pipework for connection of solid sorbent rig

Figure 31 Boiler and chilling unit located in front of solid adsorbent unit

Figure 32 Pipework and cable trays

Figure 33 Many runs of hard piping replacing previous flexible hose.

Figure 34 Installation of pipework and new control valve from after cooling heat exchanger

Figure 35 Installation of compressor and blower pipework and supports

Figure 36 Completed connection to solid sorbent rig and additional electrical and small pipework in the background

Figure 37 and figure 38 show the state of the pilot plant in May 2014.

Figure 37 Side view of pilot plant – May 2014

Figure 38 Front view pilot plant – May 2014

8 Commissioning and final preparations

The PCC pilot plant commissioning process examined the integrity of the plant and ensured that the major plant components were in working order and could be operated as intended. It is common during a commissioning process that issues and faults are identified that may have been overlooked during previous project phases. It acts as a quality control step and issues can be fixed prior to plant operation.

The commissioning of the control and instrumentation system and the mechanical and electrical components of the pilot plant has been completed. This chapter provides a summary of the commissioning activities.

8.1 Control and instrumentation system

On power up it was found that the pilot plant control system computer was faulty. The control system computer had to be upgraded to address these faults. The new process configuration brought with it a number of new issues such as the integration of new control valves, a new pump and variable speed drives. All of these required new programming to interact with the control system. Also with the plant layout not being the same as the control system some inputs/outputs were either not used anymore or required reallocation.

During instrumentation functionality checks some instruments were found to be faulty, through poor handling during relocation or water damage or some other unknown reasons. These instruments were replaced and retested.

Some errors in the control system hardware caused issues with troubleshooting problems in the field. Being aware of these inherent problems in the supplied control system hardware, replacing the control cards was identified as the best way to deal with these issues.

The starting up of the pumps indicated problems in the wiring of the variable speed drives. These electrical issues were resolved and the majority of pumps responded to control system commands.

8.2 Mechanical

The commissioning process highlighted some pipework that required modification, in particular modifications to the boiler system, column vent lines and safety relief lines were necessary. All safety relief valves were serviced and recertified.

The instrument air system was originally designed to run off a stand-alone compressor but as the compressor had suffered from corrosion beyond repair it was decided to use the power station’s compressed air supply. An air dryer was installed and the associated pipework to distribute instrument quality air around the plant for activation of valves and other consumers of compressed air was added.

The Gasmet gas analysis shed was put in place and had power supplied. This was followed by the installation of the Gasmet unit. Entry stairs, gas holders and gas lines were also installed. Purge gas and carrier gas cylinders were put in place and connected. The Gasmet system has been commissioned and is ready for testing in operation. The liquid sampling system was reinstalled and is ready for operation with solvent.

Equipment, piping and instrument labelling was also completed.

Leak testing highlighted significant issues with the pipework as leaks were present in many locations. The reason was the change-over to chemically more robust gasket materials because of the brief to enable operation with a wide range of solvents. In doing so, less pliable materials were used instead of the elastomers that the plant was originally designed for. As a result the plant has required extensive rework of the pipework to address these leaks and then meet the pressure testing requirements. Under pressure some of these leaks proved to be very difficult to repair and needed very careful adjustment of flange surfaces to ensure adequate sealing. The absorber and stripper were pressure tested and recertified. Pressure testing and commissioning highlighted a number of minor leaks in the plant. Remedying this was a sensitive task. It appeared that the vibrations on site were causing pipework to move, resulting in the creation of small leaks. After a number of iterations all leaks were sealed and the pipework was made ready for operation. An ongoing maintenance and checking program will be used to minimise the development of leaks during operation.

After completion of the leak testing and pressure testing it was found that several pumps had seized. We believe that some left-over crystals of ammonium carbonate/bicarbonate had formed in the lobes of the pump and when load was applied caused damage to the stators and further seizing of the pumps. As a result the stators on all of the mono pumps were replaced which required dismantling of the pumps and sending them for service. Every time a flange was undone replacement of the gasket was also necessary as they were not elastic enough to be reused.

Once the pumps were replaced and some additional leak tests were performed we were able to run the blower and pumps independently. Some reconfiguring of control was required for this purpose. The stripper pump had an electrical fault that proved difficult to troubleshoot but this was eventually solved.

8.3 Electrical

Cross checking and referencing of all electrical cables and connections was carried out with continuity checks. The Gasmet shed was wired into the main distribution shed and has its own circuit breaker installed. The multiplexer system for Gasmet was also installed and connections completed. Power was applied to the Gasmet and it was commissioned.

Many smaller ancillary items have been connected ready for commissioning such as the new stripper pump, communication cables, earthing cables, ambient gas sensors, boiler dosing and blow down systems, emergency stop circuit and compressed air dryer.

Electrical contractors continued to provide support for issues seen in general electrical wiring or control system as we progressed through the commissioning process.

8.4 Solar thermal project/UNSW membrane project

Much of the focus of the activities in the final stages of the project was to ensure the plant was prepared for the solar thermal integration project (a CSIRO project funded through ARENA) and working with the University of New South Wales membrane project (A CO2CRC project funded through ANLECR&D project). Extensive planning for connections and integration took place. At the time of the report writing, the solar thermal integration project is taking much of the focus and is dictating the technical progress of the plant going forward and its utilisation.

In January 2014 documents were signed outlining agreements between CSIRO, UNSW and Delta Electricity in terms of requirements for the UNSW membrane testing pilot to be integrated into the plant. Preliminary membrane testing has occurred with further work planned for the second half of 2014.

9 Lessons learnt, conclusions and recommendations

9.1 Lessons learnt

Costing calculations and quoting found that compression and expansion of flue gas streams would have a significant impact on capital cost for both the pilot plant and at larger scale.

In the case of a pressurised absorption process, the use of ammonia as a reagent in flue gas pre-treatment (SO_2 and NO_2 removal) might result in the formation of solids in the compressor/intercooling assembly. This can be avoided by an acid pre-treatment in combination with an oxidation process.

Given the issues around re-positioning of the pilot plant on the new concrete slab it is suggested that a chemset solution is preferred given the high probability of movement of bolts during the setting period.

Despite the PCC pilot plant being decommissioned at Munmorah Power Station in accordance with the pre-defined procedures, there was a considerable period of time between the decommissioning at Munmorah and the actual dismantling and transfer to Vales Point. Some unexpected deterioration of the pilot plant occurred in the meantime. A more frequent and detailed plant maintenance schedule would have assisted in preventing the deterioration. It needs to be noted however that the actual support infrastructure at Munmorah power station was also removed after the power plant shut-down.

9.2 Conclusions

In the project the Delta Electricity PCC pilot plant originally erected at Munmorah power station was successfully relocated to Vales Point power station. The PCC pilot plant was refurbished and commissioned on air and water. The project has resulted in the establishment of a sizeable technical infrastructure on the Vales Point power station site which can support the evaluation of new PCC processes for use in NSW. The resulted infrastructure has supported the conduct of three research projects:

- Evaluation of carbon based solid sorbents for PCC application (CI NSW)
- Membrane evaluation experiments (ANLEC R&D)
- Solar thermal regeneration of PCC liquid absorbents (ARENA)

9.3 Recommendations

The relocated PCC pilot plant at Delta Electricity's Vales Point power station is available for further research activities. It is recommended that funding programs (at national or state level) are established to support these research activities. The research activities can include:

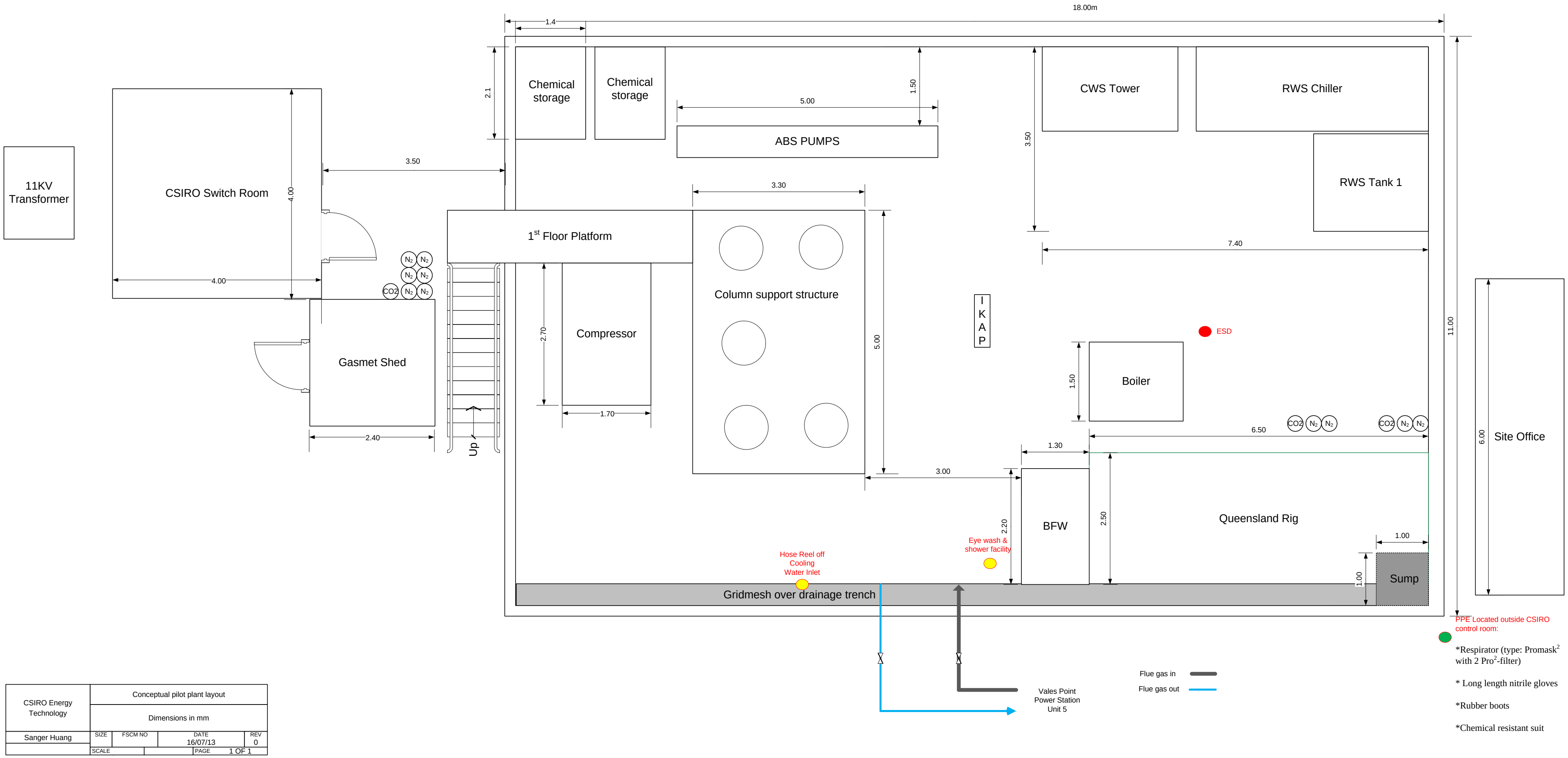
- Performance validation of amine based PCC technologies provided by commercial technology suppliers
- Validation of advanced PCC technologies based on solid sorbents and/or membranes
- Assessment of atmospheric emissions from these technologies
- Evaluation of options for integration of renewable technologies (e.g. solar thermal) with PCC

It is also recommended that the opportunities for utilisation of the CO_2 product from the PCC pilot plant in e.g. CO_2 mineralisation processes are further investigated. This would provide an opportunity for integration with other projects funded through CI NSW.

10 References

1. **Assessing Post-Combustion Capture for Coal-fired power Stations in Asia-Pacific Partnership Countries**, CSIRO Report EP116217, April 2012
2. **An improved method for CO_2 transfer from gas streams to ammonia solutions**, WO 2009/000025, Louis Wibberley
3. **Update on aqueous ammonia based post combustion capture pilot plant at Munmorah**, Hai Yu, Scott Morgan, Andrew Allport, Thong Do, Aaron Cottrell, James McGregor and Paul Feron, Distillation Absorption 2010, A.B. de Haan, H. Kooijman and A. Górak (Editors), pp. 115-120
4. **Results from Trialling Aqueous NH_3 Based Post Combustion Capture in a Pilot plant at Munmorah Power Station: Absorption**, Hai Yu, Scott Morgan, Andrew Allport, Aaron Cottrell, Thong Do, James McGregor, Leigh Wardhaugh, Paul Feron, Chemical Engineering Research and Design, 89(2011)1204-1215
5. **Results from trialling aqueous ammonia-based post-combustion capture in a pilot plant at Munmorah Power Station: Gas purity and solid precipitation in the stripper**, Hai Yu, Guojie Qi, Shujuan Wang, Scott Morgan, Andrew Allport, Aaron Cottrell, Thong Do, James McGregor, Leigh Wardhaugh, Paul Feron, International Journal of Greenhouse Gas Control, 10 (2012) 15-25

Appendix A Plant Lay-out



PPE Located outside CSIRO control room:

*Respirator (type: Promask^2 with 2 Pro^2-filter)

* Long length nitrile gloves

*Rubber boots

*Chemical resistant suit

Appendix B Project abstract

The Delta Electricity post-combustion CO_2 capture facility, originally established at the now closed-down Munmorah power station, was relocated to Vales Point power station by CSIRO with funding provided by Coal Innovation New South Wales. The relocation provided an opportunity to refurbish and update the pilot plant facilities. Originally designed for use with aqueous ammonia as the liquid absorbent for CO_2 capture, the plant has now the capability to evaluate other, amine based, liquid absorbents. The refurbishment also included the installation of structured packing material to improve the CO_2 capture performance, the installation of additional column sections and column insulation, blower replacement and provisions to allow for continuous long-term operation. Additionally, the new pilot plant location enabled the incorporation of facilities to evaluate other, non-liquid absorbent based, technologies. This unique facility is available for further use, for example, in evaluation of advanced liquid absorbent processes, process emission studies and the production of CO_2 from flue gas for the evaluation of re-use options. At present the facility is used to evaluate the use of solar thermal energy for the regeneration of liquid absorbents, which is a global first practical demonstration of this hybrid concept.

CONTACT US

t 1300 363 400
+61 3 9545 2176
e enquiries@csiro.au
w www.csiro.au

FOR FURTHER INFORMATION

Energy
Aaron Cottrell
t +61 2 4960 6053
e aaron.cottrell@csiro.au

Greenhouse gas emission comparison of two PCC processes

Ammonia based and MEA based processes

Nawshad Haque, Aaron Cottrell
December 2014

[Commercial-in-confidence]

EP161209

Process Science and Engineering & Energy Technology

Citation

Haque, N and Cottrell, A (2014) Greenhouse gas emission comparison of two PCC processes: Ammonia based and MEA based processes. CSIRO, Australia.

Copyright and disclaimer

Important disclaimer

Contents

Acknowledgments v

Executive summary 1

1 Introduction 3

2 Background 4

- 2.1 Effect of NOx and SOx 5
- 2.2 MEA solvent 6
- 2.3 Ammonia-water sorbent 6

3 Materials and methods 8

- 3.1 Goal of this study 14
- 3.2 Scope of this study 14
- 3.3 Assumptions 16
- 3.4 Life cycle inventory data 16
- 3.5 Procedure for Estimate of CO_2 Penalty 18
- 3.6 Life cycle impact assessment 19

4 Results, discussion and interpretation 20

- 4.1 NH_3 Process 22
- 4.2 MEA Process 22
- 4.3 Comparison 22

5 Sensitivity Analysis 24

6 Conclusions 25

7 Further work 26

8 References 27

Figures

Figure 1 Generic MEA process for absorption of CO_2 from flue gases (IPCC 2005) 6

Figure 2: PCC process flowsheet based on NH_3...12

Figure 3: PCC process flowsheet based on MEA 13

Figure 4: Boundary for this LCA study 15

Figure 5: GHG footprint comparison of both processes with energy penalty calculated using current grid ..21

Figure 6: GHG footprint comparison of both process with energy penalty calculated using wind power......21

Figure 7: GHG footprint comparison of no PCC, MEA and NH_3 based processes on a per MWh basis 23

Tables

Table 1 Mass and energy balance for NH3 based process 8

Table 2 Mass and energy balance for MEA based process 9

Table 3: LCI data for NH_3 process 17

Table 4: LCI data MEA process 18

Table 5: Comparison results of GHG footprint (kg CO_2-e/t CO_2 processed) for both NH_3 and MEA processes (high penalty value with lost power replaced from current grid with no PCC)..............................20

Table 6: Comparison results of GHG footprint (kg CO_2-e/t CO_2 processed) for both NH_3 and MEA processes (low penalty value with lost power replaced from wind based electricity)..................................20

Acknowledgments

Thanks are due to Do Thong for providing flowsheet and data to develop life cycle inventory tables. The report has been prepared under the project ‘1186.1 NSWCCF - Vales Pt PCC Pilot Pt WBS-R-3931-1’.

Executive summary

CSIRO Energy Technology is undertaking research to compare two processes for post combustion carbon capture (PCC). The first process is based on ammonia and the second process is based on mono-ethanol amine (MEA). The objective of this study is to estimate greenhouse gas emission (GHG) of these two processes based on life cycle assessment methodology.

The functional unit of kg CO2-e per tonne of CO2 captured does not effectively account for the efficiency of a CO2 capture process so a penalty for the efficieny of the processes studied was developed. The penalty was used to make up for lost electricity from the grid as a result of installing PCC at the power station. The penalty was assessed at two levels. One being with the electricity consumed as a result of capture being replaced by the existing electricity grid with no PCC and the other with wind powered electricity to give two extremes of the impact.

When using penalties for the higher impact of the existing electricity grid the total GHG emission was 629 kg CO_2-e for one tonne of CO_2 processed using NH_3 based process representing 38.6% of all the CO2 emissions from the life cycle going to atmosphere. In contrast, the total GHG emission was 525 kg CO_2-e for one tonne of CO_2 processed for MEA based process which is 34.4% of the life cycle emissions going to atmosphere. About 19% (ca. 111 kg CO_2-e for both NH_3 and MEA) of this emission is from actual emission from the emission stream after capture. The contribution from material use is negligible. The balance emissions for NH_3 (ca. 480 kg CO_2-e) and MEA (ca. 376 kg CO_2-e) are due to penalty for using electricity from the existing grid that is lost due to PCC plant.

The total GHG footprint of NH_3 process is about 21% higher compared with that of MEA process. This is due to several differences between these two processes. The electricity footprint of the equipment such as compressor unit in NH_3 based process is higher (248 kWh/t CO_2 processed) compared with blower in case of MEA (i.e. 26 kWh /t CO_2 procssed). This is significantly offset by the ammonia process as the regeneration energy is much lower and the energy for compression in case of NH_3 is lower than that of MEA since the output stream of CO2 is at 9.5 bar pressure in case of NH_3 but 1.75 bar pressure in case of MEA. Overall, the total CO_2 footprint is higher for NH_3 based process compared with that of MEA base process.

When comparing the technologies based on the standard functional unit used for power generation the net GHG emission footprint was reported to be 1.04 kg CO_2/kWh electricity sent out for power plant with no PCC unit with black coal. In comparison, the total GHG footprint of the power plants with PCC based on MEA is 0.15 kg CO_2-e/kWh and the GHG footprint based on NH_3 is 0.18 kg CO_2-e/kWh electricity sent out.

The results using all methods except maybe that of using windpower as the basis for the energy penalty clearly show that the more efficient technology of the two studied is the MEA based process. With this comparison in mind it should be noted that while efficiency is important the ammonia based process may be more cost effective as it can potentially utilise the existing equipment to capture the CO2, NO2, and SO2 with minimal modifications whereas the MEA based process needs to have significant investment in downstream processing of fluegas to achieve low enough SO2 and NO2 levels for the process to work effectively.

Ultimately in order to achieve reductions in CO2 emissions from primary energy sources such as power stations it is important not just to look at the life cycle efficiency but the overall cost to make those reductions.

1 Introduction

CSIRO Energy Technology is undertaking research to assess the use of ammonia solvent for post combustion carbon capture (PCC). The process has unique application to the Australian power generation industry as it is capable of capturing CO2, SO2, and NO2 in one process while at the same time being a lower cost solvent than the standard amine solvents and potentially have lower energy consumption. In order to assess the process from an environmental point of view the latest development of the ammonia based process flowsheet has been compared to the industry standard monoethanolamine (MEA) based process. The objective of this study is to estimate greenhouse gas emission (GHG) of these processes based on life cycle assessment methodology.

If the full environmental consequences of these processes are to be considered then the associated impacts need to be described quantitatively. Life cycle assessment (LCA) methodology, or ‘cradle-to-grave’ analysis, can be used to quantify the environmental impacts of a product or process. LCA seeks to examine all stages of a process’s life cycle such as material and energy inputs from the beginning to the end of the process and including consideration of the impacts of materials and energy beyond the boundary of the processing sites. The results of an LCA can be used to identify the key items that contribute to the overall impact and to compare between processes using objective methodology.

2 Background

Although post combustion capture is presently commercially used for capturing CO_2 for enhanced oil recovery (EOR) and fertiliser (urea) applications, there are a number of important issues in applying the technology to coal fired boilers for the purpose of carbon capture:

- High cost of capital, energy and reagent consumption.
- Small scale (application of the technology at full scale not realised)
- Adverse effects of NOx, SOx and unknown effects of fly ash trace elements on the solvents. This increases costs by around significantly for capture alone.

In many aspects, PCC in Australia will share similar issues to PCC applied in other countries. However, PCC in Australia will have some issues that are unique, and which may require a significantly different approach to obtain the minimum cost of CO_2 capture. These differences apply to both current and future plants:

- Australian plants have relatively low fuel costs, and therefore there is a smaller incentive to install more costly, higher efficiency plants. In the future, lower efficiency will be compounded by the increased need for dry cooling (lack of water availability for many locations), which reduces efficiency by around 1.5-2% points. PCC will increase cooling demand by around 20%, with most energy being rejected at 40-60^{o}C (working fluid side temperature). It is anticipated that the resulting increase in the cost of capture will lead to alternative technologies (solvents, processes and integration) and alternative strategies for siting plants.
- Existing Australian pf plants have neither deNOx nor deSOx equipment. Future capacity may require both at some stage. Whilst current approaches in *eg* USA, require strict control of NOx, SOx (and particulates) using sequential control technologies, it is predicted that future plants with CO_2 capture will use integrated or multi-pollutant control that will greatly change the cost of providing other emissions control (NOx, SOx, fine ash and trace elements).
- Australia has a high, and increasing, peaking requirement. PCC can be used as a discretionary load, and can be used to assist in balancing the grid so new PCC technology may have some focus on part load operability.
- Australia has high solar insolation, and PCC can use solar thermal to provide the energy for stripping (up to 120^{o}C). This is an example of integration of renewable energy with coal fired generation.

While solvents are the current benchmark technology, there are other possible technologies that could provide effective post combustion performance. All of these still require research and development, but programs are in place and progress is being made, both here and overseas. Examples of these technologies are being tested at Vales Point Pilot plant including University of NSW and CO2 CRC membrane testing rig and CSIRO solid carbon adsorption testing rig.

Chemical solvents which operate at low temperature (below 130°C) include solutions of amines, amino acids, carbonates or ammonia. These processes are most applicable to post combustion capture from dilute flue gases. The process involves contacting the cooled flue gases with a spray, or surfaces wetted with the sorbent such as in the arrangement at Vales Point Pilot plant. This gas-liquid contacting allows the solvent to capture CO_2 from the flue gases, which are then vented with around 85-90% of the CO2 removed. The CO_2-rich sorbent solution is then heated to strip the CO_2, after which it is cooled and returned to the absorber column. The stripped CO_2 is compressed, dehydrated, liquefied and pumped to pipeline pressure.

The main technical objectives with these processes are that the solvent needs to:

- Have a high absorption capacity for CO_2, exhibit a fast reaction rate, but at the same time have a low heat of regeneration (stripping). These are generally opposing properties.
- Reversibly absorb and release NOx and SOx.

- Be low cost, as all processes consume some solvent.
- Not be corrosive to mild steel – though there may be a trade-off between low cost/efficient absorbents and the need for corrosion resistant equipment.

The current industry standard process for CO2 capture is based on using monoethanolamine (MEA) as a solvent which has been developed in the natural gas processing industry over many years. The natural gas processing industry generally deals with relatively low levels of other acid gas contaminants such as SOx and NOx. The losses of solvent from these acid gases is generally accepted as the process economics are far different for producing valuable natural gas as compared to the application of CO2 capture from power station flue gases which in most circumstances purely a full cost waste treatment process.

2.1 Effect of NOx and SOx

In other developed countries, coal fired plant is fitted with deNOx and deSOx equipment, with mercury emissions control now being developed for implementation also. In most cases, this enables PCC using standard liquid sorbents to be used, without significant formation of heat stable salts or related degradation products. Current PCC technologies require that NO_2 and SOx be reduced to below 5-10 ppmv, though the actual amount allowed will be a trade-off between:

- Solvent losses (and therefore solvent cost) through the formation of heat stable salts.
- Capital and reagent costs for a caustic polishing absorber before the PCC plant.
- Improving the performance of existing deNOx and deSOx equipment

For Australian plants, the current levels of these acid gases in the flue gas would result in unacceptable degradation of current solvents. Retrofitting of separate deNOx and deSOx control plant to Australian power station adds considerable extra expense (would increase the cost of capture by 20-35%) – so the challenge is to either develop solvents which can be used economically with the current level of NOx and SOx in the flue gases, such as with the use of ammonia as a solvent, or to develop an integrated approach to emissions control which is also being considered by CSIRO in its CoCapCo project.

Multi-pollutant emissions control is already emerging as a possible alternative to separate and sequential deNOx, ultra-fine particulates removal, deSOx, and mercury control for coal-fired plants – mostly based on a high efficiency contactor. The need for PCC will increase the potential for this approach, as some of the requirements for multi-pollutant emissions control are common with those required for PCC. It is therefore envisaged that the lowest cost approach will be fully integrated emissions control.

For PCC, there are two promising developments in integrated emissions control including processes similar to the existing Cansolv process and CSIROs CoCapCo process which capture SOx and CO_2, both of which recover the solvent in a multistage capture and stripping approach and the aqueous ammonia process which could capture SOx, NOx, mercury and CO_2 while allowing the ammonia to be consumed to produce valuable by-products and which is still in the early stages of development and consideration by CSIRO and others.

Cansolv[i] has commercialised amine based technology for SO_2 recovery/removal from a variety of processes, and has developed two additional technologies: a sequential absorption tower process for multi-pollutant (SO_2, NOx and mercury) control, and a CO_2 process using amines. All of these processes use liquid sorbents (amines are used for SO_2 and CO_2 removal), and are designed to be integrated into a total emissions control system. A slipstream of the amines is purified to prevent accumulation of heat stable salts.

Aqueous ammonia as a solvent for integrated emissions control is also an interesting prospect, with the possibility of producing fertiliser by-products (ammonium sulphate and nitrate), and requiring less energy for CO_2 stripping from the ammonium bicarbonate. The claimed advantages of aqueous ammonia over MEA are:

- CO_2 absorption capacity up to two times greater.

- less heat to strip the CO_2 and regenerate the absorbent.
- Reagent makeup costs approximately 85% lower than amine based technologies

2.2 MEA solvent

MEA (monoethanolamine) as a water based solution (15-30 wt. % MEA) is the most commonly used sorbent for capture. MEA plants typically capture 85-90% of the CO_2 from the gas stream, at a purity of >99%. The dominant equilibrium reactions (for absorption and stripping) are as follows:

$$2\ R\text{-}NH_2 + CO_2 \leftrightarrow R\text{-}NH_3^+ + R\text{-}NH\text{-}COO^- \text{ (dominant reaction)}$$

$$R\text{-}NH_2 + CO_2 + H_2O \leftrightarrow R\text{-}NH_3^+ + HCO_3^-$$

A schematic diagram of the MEA-based process is shown in Figure 1.

As MEA is a base, it reacts irreversibly with acid gases SOx and NO_2 to form stable salts which do not regenerate in the stripper. This leads to solvent loss, as well as disposal problems since some of the salts (formates) are particularly toxic (but these could possibly be destroyed by incineration in the pf plant). A typical MEA based process would require that the SOx and NOx content of flue gas must therefore be reduced to below 10 ppmv, and for plants with existing deSOx and deNOx, this will require additional processing to achieve these levels. For plants without SOx or NOx control (ie Australian plants), the issue is more complex, and needs further investigation to determine the optimum solution (eg partial control using a modified direct contact cooler and with a higher reagent cost, or use of other sorbents – chemical or physical).

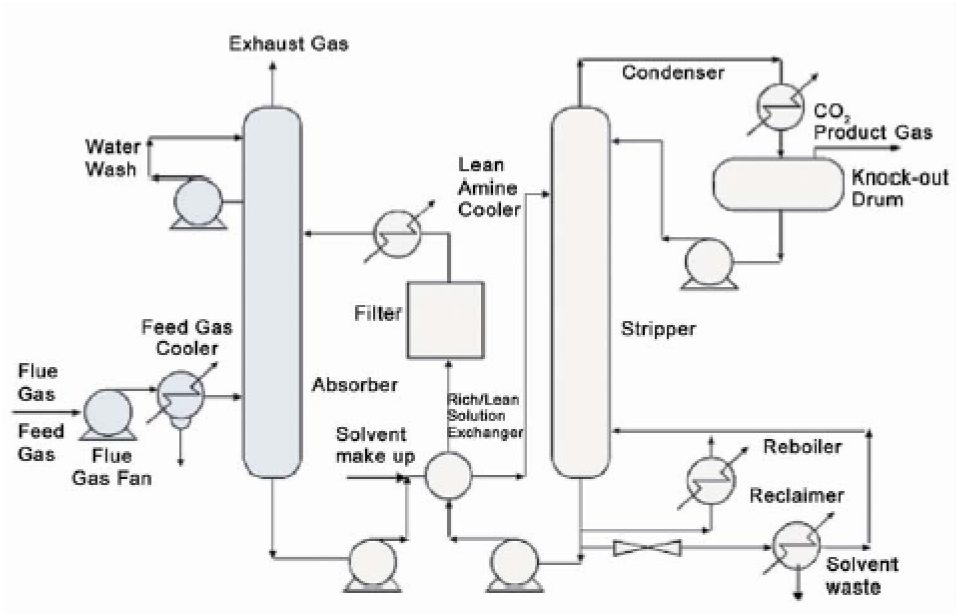


Figure 1 Generic MEA process for absorption of CO_2 from flue gases (IPCC 2005)

2.3 Ammonia-water sorbent

A new chemical solvent under development is aqueous ammonia in the concentration range up to 24% by weight of ammonia. Aqueous ammonia reacts with CO_2 (together with NOx and SOx) to form ammonium bicarbonate, ammonium nitrate and ammonium sulfate, respectively. The sorbent thereby provides a one-step process. The cycle of absorption and regeneration can be driven by either temperature or pressure swing. The dominant equilibrium reaction is:

$$2NH_4HCO_3 \leftrightarrow (NH_4)CO_3 + CO_2 + H_2O$$

Ammonia is the simplest amine available to capture CO2 from flue gas and as one of the promising solvents for CO2 capture. Compared to traditional amines, ammonia is a low cost solvent and does not degrade in the presence of O2 and other species present in the flue gas. Moreover, it has a high CO2 removal capacity, low absorption heat and hence low regeneration energy. It has also the potential of capturing multicomponents (NOx, SOx and CO2) and producing value added chemicals, such as ammonium sulfate and ammonium nitrate, which are commonly used as fertilizers. The advantage of multicomponents capture by aqueous ammonia is of particular interest to Australian power stations since flue gas desulphurisation (FGD) of SOx and selective catalytic reduction (SCR) of NOx are not implemented in Australia.

Compared to the traditional amine based process the ammonia based process is far less developed. Alstom and Powerspan have looked into different variations of the technology and CSIRO is also investigating this technology for application to the Australian electricity industry. There is ongoing research within CSIRO looking at various ways to apply the ammonia based solvent to CO2 capture and the Vales Point Pilot plant is one of the tools being utilised for this research.

The operational experience with the aqueous ammonia pilot plant at Vales Point power station has confirmed these benefits, but also revealed further challenges:

- The ammonia losses, as a result of its high volatility can be substantial depending on the operating conditions and this necessitates the installation of a comprehensive gas washing system and operation at low temperature,
- The CO_2 absorption rates are low, which will result in much larger absorbers compared to the standard amine processes and hence higher investment costs,
- Operating the desorber similar to regular amine processes will result in the formation of ammonium-bicarbonate solids, which will block the condenser,
- The requirement for cooling in an aqueous ammonia process is quite high, which results in a sizeable additional energy requirement, particularly when applied in Australia.

The relocated pilot plant has some process modifications to address these issues including:

- Replacement of dumped packing with structured packing material to improve the CO_2 capture rate
- Installation of additional column sections to increase the ammonia recovery
- Installation of column lagging to enable operation at lower temperatures
- Addition of a flue gas compressor to allow pressurised absorption which aims to reduce ammonia slip, increase reaction kinetics, minimise absorber size and allow for higher temperature operation (ie no chilling required).
- Various piping configurations to minimise or eliminate precipitate formation which is a major operational issue.

3 Materials and methods

There is an international standard (ISO 14044, 2006) and softwares to undertake LCA studies. SimaPro 7.3.3 (PRe, 2013) software has been used to undertake this study.

Two flowsheets have been developed using ASPEN software for a 660 MW power plant. The mass and energy balances were calculated for both flowsheets. The unit processes have been identified and the equipments were listed. The flowsheets have been redrawn from ASPEN and are shown in Figures 1 and 2.

The mass and energy balances for the two processes are shown in Table 1 and Table 2with the stream names in the tables referring to the streams in the indicated on the figures. The stream names are taken from the ASPEN model and represent solvent flue gas and wash water streams. Please refer to the flowsheets shown in Figures 1 and 2 for details.

Table 1 Mass and energy balance for NH3 based process

	LEANGAS	MAKEUP	S10	S11	S12	S13	S14
Mass Flow kg/sec							
H2O	8.0E+00	5.5E-02	1.4E+03	8.0E+00	1.4E+03	1.5E+03	1.5E+03
NH3	5.9E-05	4.6E-02	3.2E+00	5.9E-05	3.2E+00	7.9E+01	5.7E+01
CO2	2.2E+01	0.0E+00	1.9E+00	2.2E+01	1.9E+00	4.9E+00	3.4E-02
NH4+	0.0E+00	3.4E-04	7.5E+01	0.0E+00	7.5E+01	4.7E+01	5.9E+01
OH-	0.0E+00	3.2E-04	6.6E-05	0.0E+00	6.6E-05	7.7E-03	1.8E-03
HCO3-	0.0E+00	0.0E+00	2.0E+02	0.0E+00	2.0E+02	1.1E+02	4.2E+01
CO3-2	0.0E+00	0.0E+00	1.4E+01	0.0E+00	1.4E+01	8.9E+00	4.5E+01
NH2CO2-	0.0E+00	0.0E+00	2.6E+01	0.0E+00	2.6E+01	3.2E+01	6.8E+01
N2	7.3E+02	0.0E+00	4.8E-01	7.3E+02	4.8E-01	2.7E-27	0.0E+00
H3O+	0.0E+00	4.1E-15	5.4E-07	0.0E+00	5.4E-07	7.5E-06	7.4E-08
NH4HCO3S	0.0E+00	0.0E+00	2.4E+02	0.0E+00	2.4E+02	0.0E+00	0.0E+00
SO2	6.0E-02	0.0E+00	0.0E+00	6.0E-02	0.0E+00	0.0E+00	0.0E+00
NH4HSO3S	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH4X2SO3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH42SO3W	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
HSO3-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
SO3--	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Total Flow kg/sec	765	0.10	2004	765	2004	1810	1810
Temp. °C	47	25	18	327	18	134	30
Pressure bar	7	1.2	7.01	7	10.1	9.52	9.51

	S15	S16	S18	S19	S20	S21	S22
Mass Flow kg/sec							
H2O	1.5E+03	1.5E+03	3.7E-01	5.4E+01	6.9E+01	1.0E+03	1.0E+03
NH3	5.7E+01	5.3E+01	1.1E-03	3.9E-04	0.0E+00	3.5E-04	3.6E-04
CO2	3.4E-02	9.9E-03	1.9E+02	2.2E+02	2.2E+02	1.4E-01	1.4E-01
NH4+	5.9E+01	6.1E+01	0.0E+00	0.0E+00	0.0E+00	2.5E+00	2.5E+00
OH-	1.8E-03	1.1E-03	0.0E+00	0.0E+00	0.0E+00	8.0E-08	8.0E-08
HCO3-	4.2E+01	2.7E+01	0.0E+00	0.0E+00	0.0E+00	9.2E-03	9.2E-03
CO3-2	4.5E+01	5.0E+01	0.0E+00	0.0E+00	0.0E+00	1.1E-07	1.1E-07
NH2CO2-	6.8E+01	7.6E+01	0.0E+00	0.0E+00	0.0E+00	2.5E-07	2.5E-07
N2	0.0E+00	0.0E+00	4.8E-01	7.4E+02	7.4E+02	1.2E-02	1.2E-02
H3O+	7.4E-08	2.0E-08	0.0E+00	0.0E+00	0.0E+00	3.8E-04	3.8E-04
NH4HCO3S	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

SO2	0.0E+00	0.0E+00	0.0E+00	3.3E-01	5.6E-01	1.3E-02	1.3E-02
NH4HSO3S	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH4X2SO3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH42SO3W	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
HSO3-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.2E+01	1.2E+01
SO3--	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	8.1E-02	8.1E-02
Total Flow kg/sec	1810	1810	195	1005	1021	1014	1014
Temp. °C	30	10	30	43	48	48	48
Pressure bar	9.51	7.1	9.5	1	1.01325	1.02	7.1

	S23	**S24**	**S25**	**S27**	**S28**	**S30**	**S32**
Mass Flow kg/sec							
H2O	9.8E+02	1.9E+01	1.0E+01	5.4E+01	8.0E+00	1.4E+00	9.8E+02
NH3	3.5E-04	6.8E-06	0.0E+00	3.9E-04	5.9E-05	0.0E+00	6.7E-04
CO2	1.4E-01	2.7E-03	0.0E+00	2.2E+02	2.2E+01	2.2E+02	1.6E-01
NH4+	2.5E+00	4.8E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.5E+00
OH-	7.9E-08	1.5E-09	9.2E-09	0.0E+00	0.0E+00	0.0E+00	1.4E-07
HCO3-	9.0E-03	1.7E-04	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.4E-02
CO3-2	1.1E-07	2.1E-09	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.3E-06
NH2CO2-	2.5E-07	4.8E-09	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.4E-06
N2	1.2E-02	2.3E-04	0.0E+00	7.4E+02	7.3E+02	7.4E+02	1.2E-01
H3O+	3.7E-04	7.1E-06	1.0E-08	0.0E+00	0.0E+00	0.0E+00	1.0E-04
NH4HCO3S	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
SO2	1.3E-02	2.5E-04	0.0E+00	3.3E-01	6.0E-02	0.0E+00	2.7E-03
NH4HSO3S	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH4X2SO3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NH42SO3W	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
HSO3-	1.1E+01	2.2E-01	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.1E+01
SO3--	7.9E-02	1.5E-03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.2E-01
Total Flow kg/sec	995	19	10	1005	765	952	998
Temp °C	48	48	10	337	147	14	37
Pressure bar	7.1	7.1	7.01	7.11	1	7.1	7.02

Table 2 Mass and energy balance for MEA based process

	CO2OUT	**D1**	**D2**	**D3**	**DWASTE**	**DWATER**	**F1**
Mass Flow kg/sec							
MEA	1.7E-08	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
H2O	2.0E+00	2.8E+03	2.8E+03	2.9E+03	4.9E+01	1.6E+01	6.9E+01
CO2	1.9E+02	5.4E-01	5.6E-01	5.9E-01	1.0E-02	0.0E+00	2.2E+02
N2	2.0E-01	4.4E-02	4.4E-02	4.5E-02	7.7E-04	0.0E+00	7.4E+02
SO2	4.1E-04	1.4E-03	1.3E-03	1.7E-03	2.9E-05	0.0E+00	5.6E-01
H3O+	0.0E+00	5.6E-05	5.8E-05	6.6E-05	1.1E-06	1.5E-14	8.1E-06
OH-	0.0E+00	3.2E-06	2.2E-06	2.7E-06	4.6E-08	1.7E-01	2.0E-10
HCO3-	0.0E+00	5.9E-01	5.6E-01	5.5E-01	9.3E-03	0.0E+00	2.6E-05
CO3-2	0.0E+00	1.5E-04	1.3E-04	1.2E-04	2.0E-06	0.0E+00	4.4E-11
MEAH+	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
MEACOO-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
SO3-2	0.0E+00	5.1E+00	5.1E+00	4.4E+00	7.5E-02	0.0E+00	0.0E+00
NA+	0.0E+00	1.0E+01	1.0E+01	1.0E+01	1.7E-01	2.3E-01	0.0E+00
HSO3-	0.0E+00	2.5E+01	2.5E+01	2.7E+01	4.5E-01	0.0E+00	0.0E+00
Total Flow kg/sec	196	2868	2868	2902	49	16	1021

Temp. °C	30	40	35	40	40	20	44
Pressure bar	1.75	1.01	1.01	0.99	1.01	1.01	1

	F2	F3	F4	GAS2	GASOUT	L1	LEANIN
Mass Flow kg/sec							
MEA	0.0E+00	0.0E+00	0.0E+00	2.8E-03	2.8E-03	4.9E+02	4.9E+02
H2O	3.6E+01	3.6E+01	3.6E+01	1.4E+02	1.4E+02	1.8E+03	1.9E+03
CO2	2.2E+02	2.2E+02	2.2E+02	2.1E+01	2.1E+01	1.4E-03	4.9E-04
N2	7.4E+02	7.4E+02	7.4E+02	7.4E+02	7.4E+02	0.0E+00	0.0E+00
SO2	1.5E-02	1.5E-02	1.5E-02	1.0E-02	1.0E-02	3.8E-03	0.0E+00
H3O+	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.1E-08	9.7E-09
OH-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	9.6E-03	8.8E-03
HCO3-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.7E+00	2.7E+00
CO3-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.1E+00	4.1E+00
MEAH+	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	2.6E+02	2.6E+02
MEACOO-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	4.1E+02	4.1E+02
SO3-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NA+	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
HSO3-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Total Flow kg/sec	987	987	987	893	893	2994	3110
Temp. °C	35	53	45	63	96	55	40
Pressure bar	0.94	1.1	1.09	1.062	1.047	1.78	1.09

	LEANOUT	MAKEUP	R1	RICHIN	RICHOUT	WA3	WATERIN
Mass Flow kg/sec							
MEA	5.0E+02	2.8E-03	3.4E+01	1.3E+02	3.5E+01	1.8E-01	1.9E-01
H2O	1.8E+03	0.0E+00	1.8E+03	1.8E+03	1.8E+03	1.2E+02	2.2E+02
CO2	1.6E-01	0.0E+00	2.9E-01	4.0E+01	3.0E-01	1.2E-03	5.7E-04
N2	9.7E-18	0.0E+00	2.0E-01	2.0E-01	2.0E-01	1.3E-03	1.4E-03
SO2	3.8E-03	0.0E+00	4.2E-03	4.2E-03	4.2E-03	1.6E-05	1.7E-05
H3O+	4.2E-07	0.0E+00	4.4E-07	1.5E-06	4.6E-07	9.6E-09	7.5E-09
OH-	9.3E-03	0.0E+00	6.7E-04	2.5E-03	1.5E-05	6.1E-05	9.9E-05
HCO3-	1.6E+01	0.0E+00	8.9E+01	7.9E+01	9.0E+01	2.0E-01	2.1E-01
CO3-2	8.5E-01	0.0E+00	1.0E+01	3.0E+00	1.0E+01	6.0E-03	1.2E-02
MEAH+	2.5E+02	0.0E+00	5.4E+02	4.8E+02	5.4E+02	2.6E-01	2.8E-01
MEACOO-	4.0E+02	0.0E+00	7.2E+02	6.5E+02	7.1E+02	8.0E-02	6.7E-02
SO3-2	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
NA+	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
HSO3-	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Total Flow kg/sec	2994	0.003	3191	3191	3191	116	223
Temp. °C	119	25	46	101	46	63	46
Pressure bar	1.79	1.5	1.9	1.89	1.087	1.2	1.2

	WATERMU	WATEROUT
Mass Flow kg/sec		
MEA	0.0E+00	3.6E-01
H2O	1.0E+02	2.4E+02
CO2	0.0E+00	2.5E-03
N2	0.0E+00	2.7E-03
SO2	0.0E+00	3.3E-05
H3O+	1.8E-07	2.0E-08
OH-	1.6E-07	1.2E-04
HCO3-	0.0E+00	4.0E-01

CO3-2	0.0E+00	1.2E-02
MEAH+	0.0E+00	5.3E-01
MEACOO-	0.0E+00	1.6E-01
SO3-2	0.0E+00	0.0E+00
NA+	0.0E+00	0.0E+00
HSO3-	0.0E+00	0.0E+00
Total Flow kg/sec	103	236
Temp. °C	25	63
Pressure bar	1.2	1.062

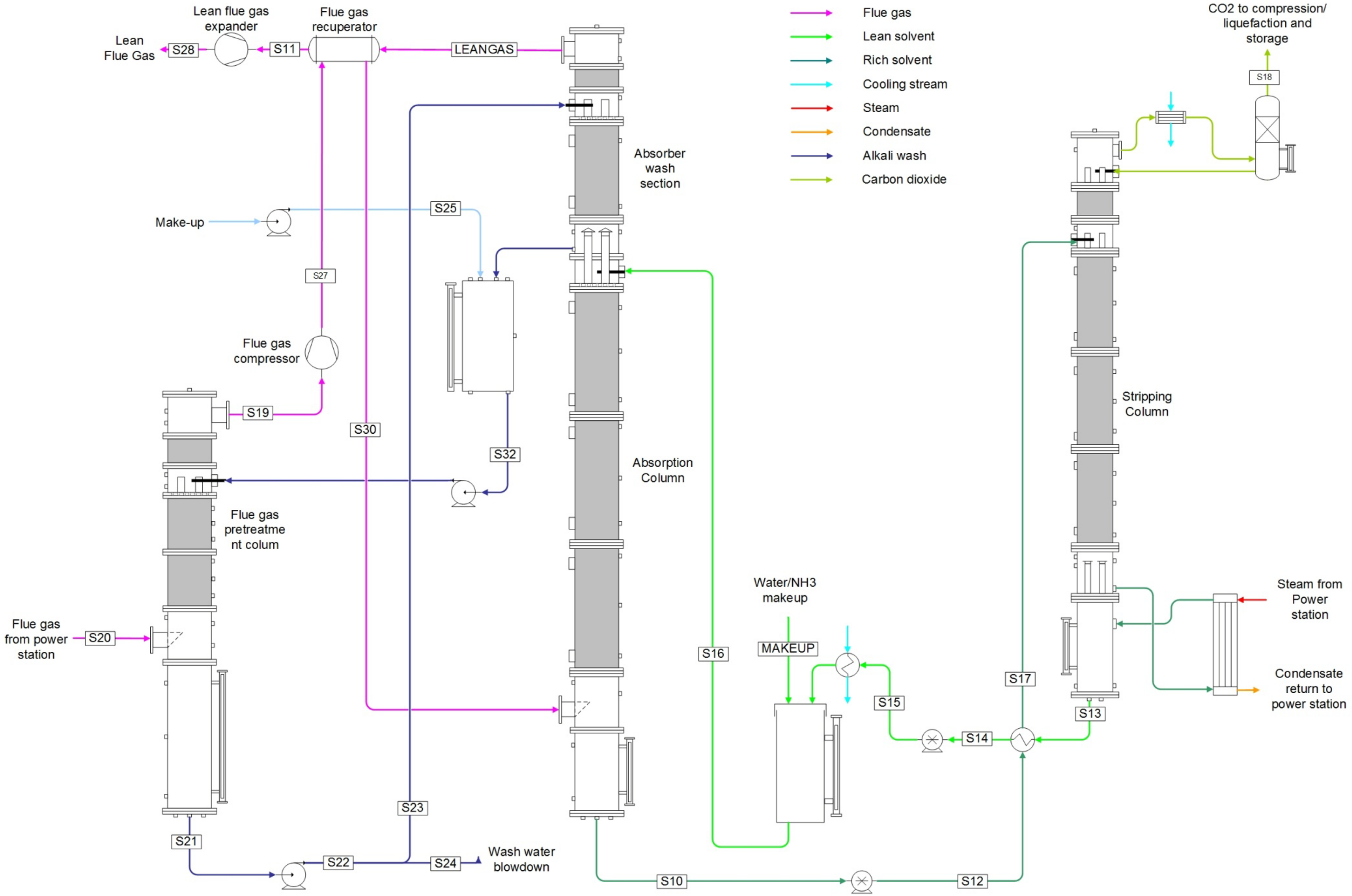


Figure 2: PCC process flowsheet based on NH_3

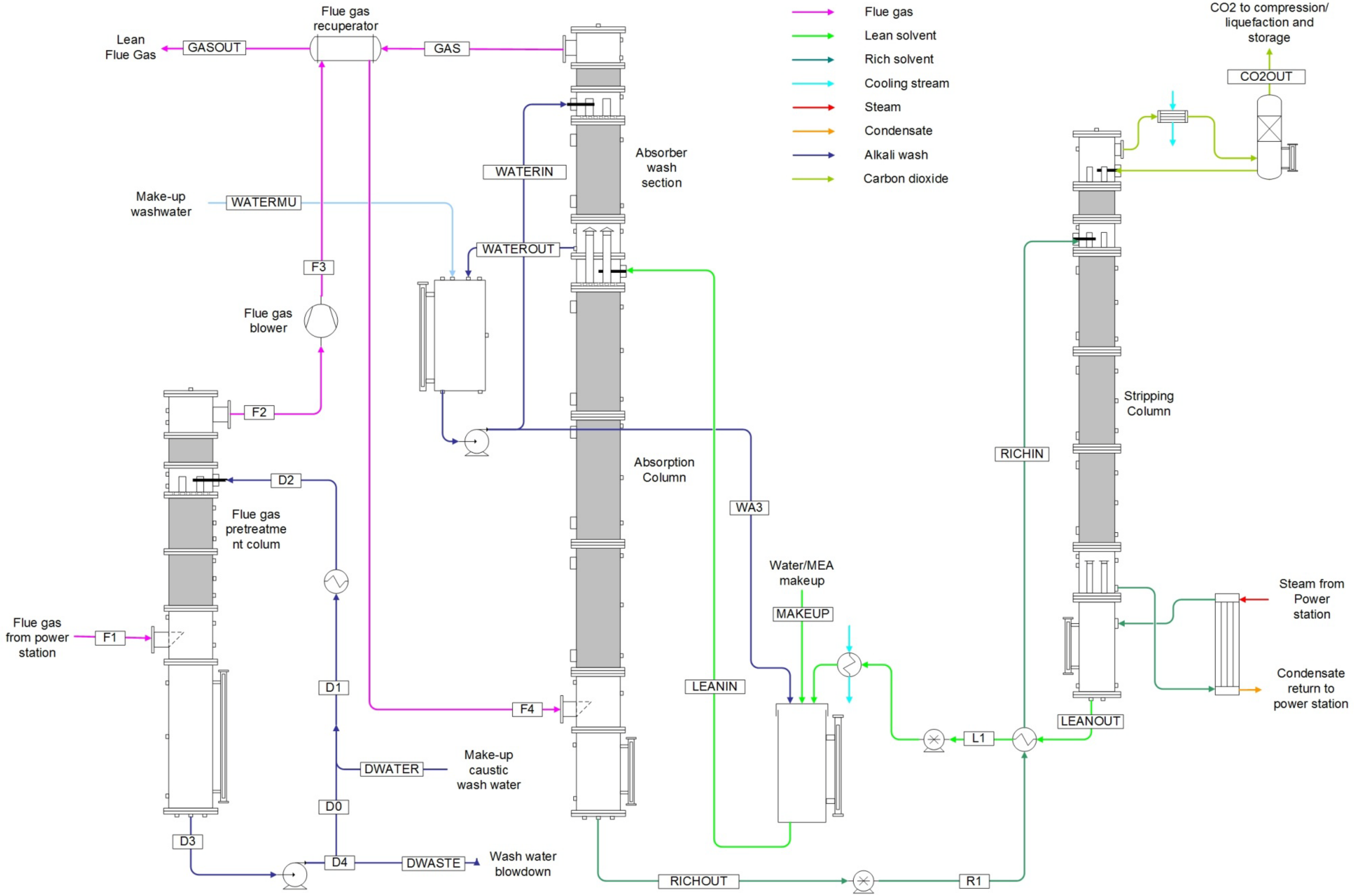


Figure 3: PCC process flowsheet based on MEA

3.1 Goal of this study

There is a need to compare the net greenhouse gas emission for two technology options for PCC. The intended application is to find potential key contributors of the process and to assist with the direction of research on particular technology and the priorities. The target audience are the project team members, CSIRO colleagues and other external stakeholders.

The main objective is to identify the so called ‘hotspots’ of the respective processes. Although a comparison has been made, the comparison is only indicative of the process configurations studied. Other process configurations using the same solvents may achieve different outcomes so the comparison should not be interpreted as representing any other technologies or process configurations using the same solvents.

3.2 Scope of this study

The scope of this study has been identified after the delineation of the boundary. This boundary for both processes has been demarcated as ‘cradle to gate’ study. The coal mining, transportation, power production, post combustion capture and compression of processed output CO_2 has been included. Both processes would similarly then be liquefied and stored in an appropriate storage site but these processes have not been included. The boundary for this LCA is shown in Figure 3. Construction of the power station and PCC pilot plants have not been addressed in this study as from experience these aspects add very little impact when considered over the full life of plant which is generally in excess of 40 years.

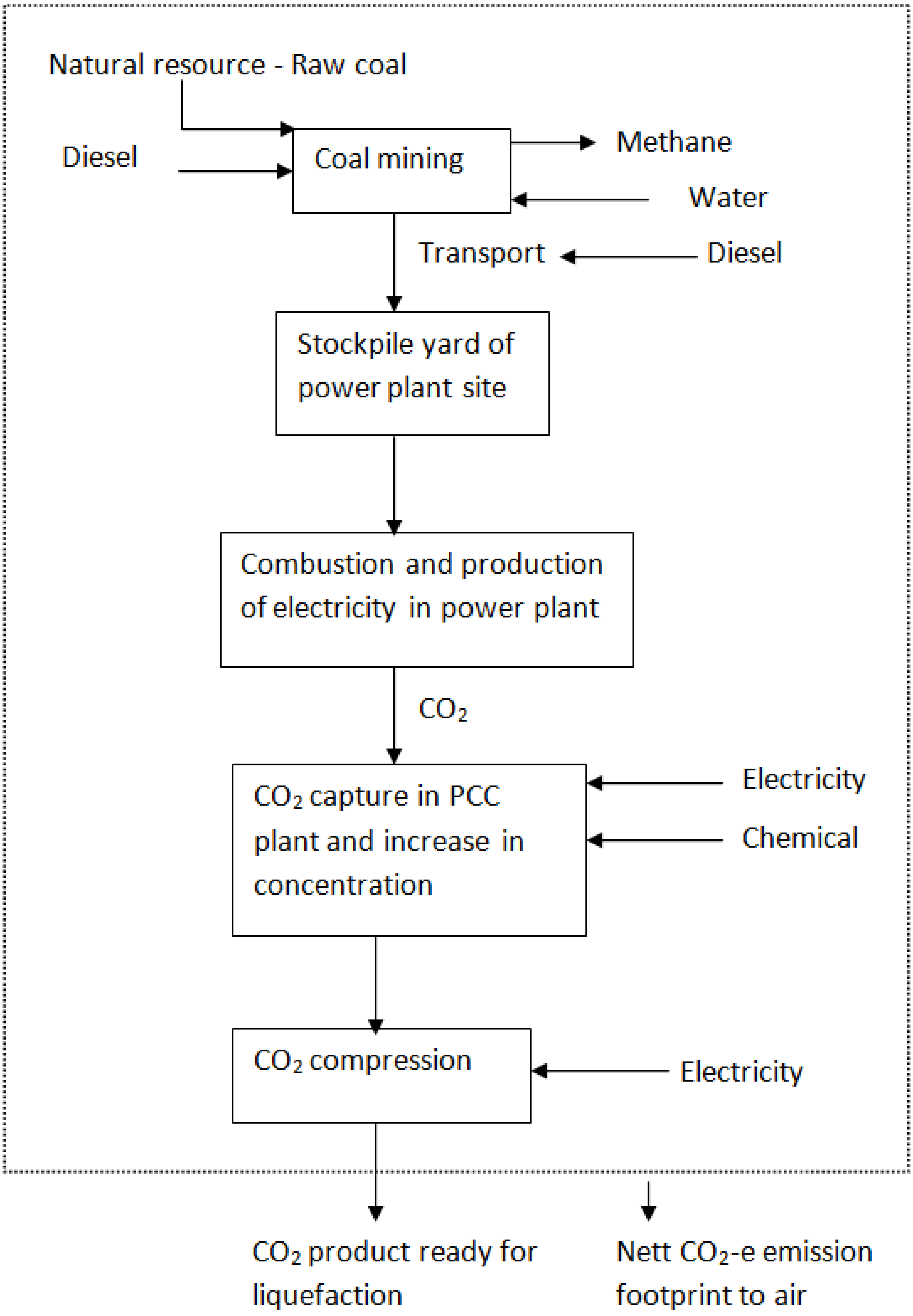


Figure 4: Boundary for this LCA study

The functional unit for this study is 1 tonne of CO_2 processed and ready for liquefaction step for further sequestration measures. For ease of comparison to other generating technologies, this unit has also been expressed in kg CO_2/kWh of electricity sent in Figure 5.

The contribution of make-up chemicals after continuous steady-state operation has been estimated. However, the contribution from the first-fill for NH_3 or MEA processes has not been considered at this stage.

3.3 Assumptions

The following main assumptions have been made to undertake this study.

- Plant availability: 90% or 7,884 hours
- Reference power-station efficiency: 35.6%
- Reference power-station CO_2 emission factor: 1040 kg CO_2/MWh for NSW state electricity (SimaPro database, AusLCI 2013)
- Net capture of CO_2: 90%
- Compression pressure of CO_2 increased before liquefaction: 1.75 to 90 bar for MEA and 9.5 to 90 bar for NH_3 based process
- Energy of black coal: 27 GJ/t
- Average transport distance by rail from coal mine to power plant: 100 km

There are other appropriate and reasonable assumptions made to carry out this LCA study.

3.4 Life cycle inventory data

Life cycle inventory (LCI) data tables have been developed based on the flowsheet data, mass and energy balances.

The inventory data for NH_3 and MEA processes are shown in Tables 1 and 2, respectively.

Table 3: LCI data for NH_3 process

ITEMS	VALUES	UNIT	SOURCE OF DATA OR COMMENTS
Coal mining	0.35	t coal used/t CO_2 processed	This estimate is based on power station capacity (669.8 MW), efficiency (35.6%) and coal energy value (27 MJ/kg)
Coal transport	35	t.km/t CO_2 processed (0.35 t over 100 km distance)	100 km is assumed distance by rail
Pumping (through cooling tower)	0.04	kWh/t CO_2 processed	Electrical energy required, estimated from the ASPEN software
Wash water pump	0.01	kWh/t CO_2 processed	Same as above
Rich solvent pump	0.84	kWh/t CO_2 processed	Same as above
Flue gas compressor and expander (nett after heat recovery)	248.00	kWh/t CO_2 processed	After compression, the stream will expand and there is an opportunity for heat recovery
Pump (Chillers)	0.84	kWh/t CO_2 processed	Estimate from ASPEN
NH_3 makeup	0.21	kg NH_3/t CO_2 processed	Estimate from ASPEN
CO_2 Emission stream to air	0.11	t/t CO_2 processed	Emitted to atmosphere after PCC process
Desorber energy use in PCC	145.47	kWh/t CO_2 processed	This is due to consumption of steam by PCC installation from the power plant
Energy for CO2 compression before liquefaction	66.0	kWh/t CO_2 processed	In a two-stage compression from 9.5 bar to 90 bar (assume 70% of MEA)
Total electricity footprint of PCC plant	461.20	kWh/t CO_2 processed	This is due to all electricity use in PCC

Table 4: LCI data MEA process

ITEMS	VALUES	UNIT	COMMENTS
Coal mining	0.35	t coal used/t CO_2 processed	Same as Table 1
Coal transport	35	t.km/t CO_2 processed (0.35 t over 100 km distance)	Same as above
Pumping (through cooling tower)	0.04	kWh/t CO_2 processed	Estimate from ASPEN
Wash water pump	0.01	kWh/t CO_2 processed	Same as above
Rich Solvent Pump	0.39	kWh/t CO_2 processed	Same as above
Blower	25.97	kWh/t CO_2 processed	Same as above
MEA makeup	0.14	kg/t CO_2 processed	Same as above
CO_2 Emission stream to air	0.11	t/t CO_2 processed	Same as Table 1
Stripper energy used in PCC plant	217.00	kWh/t CO_2 processed	Due to steam consumption
Energy for compression before liquefaction	94.0	kWh/t CO_2 processed	In a three-stage compression from 1.75 bar to 90 bar (assumed based on EU Report, 2011)
Total electricity footprint of PCC plant	337.41	kWh/t CO_2 processed	This is due to all electricity use in PCC

3.5 Procedure for Estimate of CO_2 Penalty

The functional unit of kg of CO_2 /t CO2 captured does not easily handle efficiencies in the CO2 capture process directly. The functional unit chosen looks at the greenhouse gas emissions emitted to capture 1t of CO2. In simple terms if there were two processes producing electricity as its main product for example and one of those processes consumed 90% of its power to capture 90% of its CO2 emissions giving a greenhouse emission factor of around 110 kg CO2/t CO2 captured, this would look better than a process that consumed 30% of its power to capture 80% of its emissions giving a greenhouse gas emission factor of 250 kg CO2/t CO2 captured. Obviously the second process is far more efficient but due to the functional unit chosen this is overlooked. Comparing the processes on a more appropriate basis such as based on the primary product of power delivered to the grid you see that second is better than the first.

In order to account for the efficiency factor it was decided that there would be an emission penalty factor as less efficient PCC processes would require additional makeup power from the grid to maintain full grid supply. This adds an extra complication as to whether to assume that the current grid arrangement and CO2 intensity would apply or whether there would be a reduction due to new installed plant such as post combustion capture and renewable. To give both ends of the spectrum results for both the current grid and and an ideal renewable scenario of wind were chosen to give the limits of what would be expected.

To establish the penalty the total CO_2-e footprint of both processes has been calculated. The components include CO_2 emission from the loss of electrical power due to instalment of a PCC with an existing power plant. This component includes two categories.

The first component includes all the machineries and equipment such as pumps, compressors or blowers used for PCC within the power plant complex. These equipments will draw electric power from the power plant. The power used from the plant will not emit any CO_2 directly because any CO_2 emitted will be captured in PCC plant. The remaining amount of CO_2 that is not captured in PCC plant is accounted as emission stream to the air.

The second penalty is the due reduction of power produced at the power station as the PCC unit consumes some of the usable steam supply which would normally be used for power generation.

The reduction in power sent to the grid from the power station utilising PCC thus need to be supplied from the NSW State Electricity grid. This carbon emission from this NSW grid is currently found to be 1.04 kg CO_2/kWh (Australasian LCI, 2013; PRe, 2013). The results of this penalty is shown in Table 5. On the other hand if the power reduction is displaced renewable energy such as wind then when using a CO2 emission factor from wind power of 0.0165 kg CO_2/kWh (Australasian LCI, 2013; PRe, 2013). This electricity from this grid will have lower CO_2 emission as shown in Table 6.

3.6 Life cycle impact assessment

Carbon emission from power plants is a major contribution towards the increase of CO_2 concentration in the atmosphere globally. Thus global warming potential (GWP) has been selected as the main impact category for this particular study. The units of GWP and GHG emission is expressed in kg CO_2-e unit. The GHG values have been estimated for both processes considering all materials and energy use for each PCC process. It is to note that electrical energy used as electricity and steam for the PCC processes do not add any additional emission sources but just reduce the generation efficiency of the station. Thus the CO_2 emission streams going to the air are considered here (from coal mining, emission outside the power plant site and brought with the material (e.g. due to chemical use) and diesel energy).

LCA studies can include other impacts such as acidification, abiotic depletion, ozone layer depletion, toxicity, land use etc. These numbers can be generated and reported if needed but the associated values a far less reliable due to the immaturity of the technologies for this purpose. For this study, CO_2 emission has the main focus since this is the most significant impact from a power plant.

The results can be normalised for Australian population by estimating per capita impact. There is a debate among the LCA practitioners about use of weighting factors for each indicators this might introduce subjectivity with the results. This study has not used any weighting factors.

4 Results, discussion and interpretation

Table 5: Comparison results of GHG footprint (kg CO_2-e/t CO_2 processed) for both NH_3 and MEA processes (high penalty value with lost power replaced from current grid with no PCC)

ITEMS	NH_3	MEA	COMMENTS
CO2 Emission stream to air	111.11	111.11	This is final emission stream after 90% capture
Coal Mining	37.5	37.5	Same amount of coal used in both scenarios
Coal transport	0.37	0.37	As above
NH_3/MEA	0.40	0.07	Difference is due to two different chemicals used and their quantity
Penalty for power taken from the NSW Grid for lost power	476.65	376.93	Difference due to loss of power from the plant and uptake of power from NSW State grid
Total	629.03	525.98	About 5% higher in NH_3 compared with MEA process

Table 6: Comparison results of GHG footprint (kg CO_2-e/t CO_2 processed) for both NH_3 and MEA processes (low penalty value with lost power replaced from wind based electricity)

ITEMS	NH_3	MEA	COMMENTS
CO2 Emission stream to air	111.11	111.11	This is final emission stream after capture
Coal Mining	37.5	37.5	Same amount of coal used in both scenarios
Coal transport	0.37	0.37	As above
NH_3/MEA	0.40	0.07	Difference is due to two different chemicals used and their quantity
Penalty for power taken from the wind power for lost power	7.61	5.98	Difference due to loss of power from the plant and uptake of power from wind turbines
Total	156.99	155.03	About 5% higher in NH_3 compared with MEA process

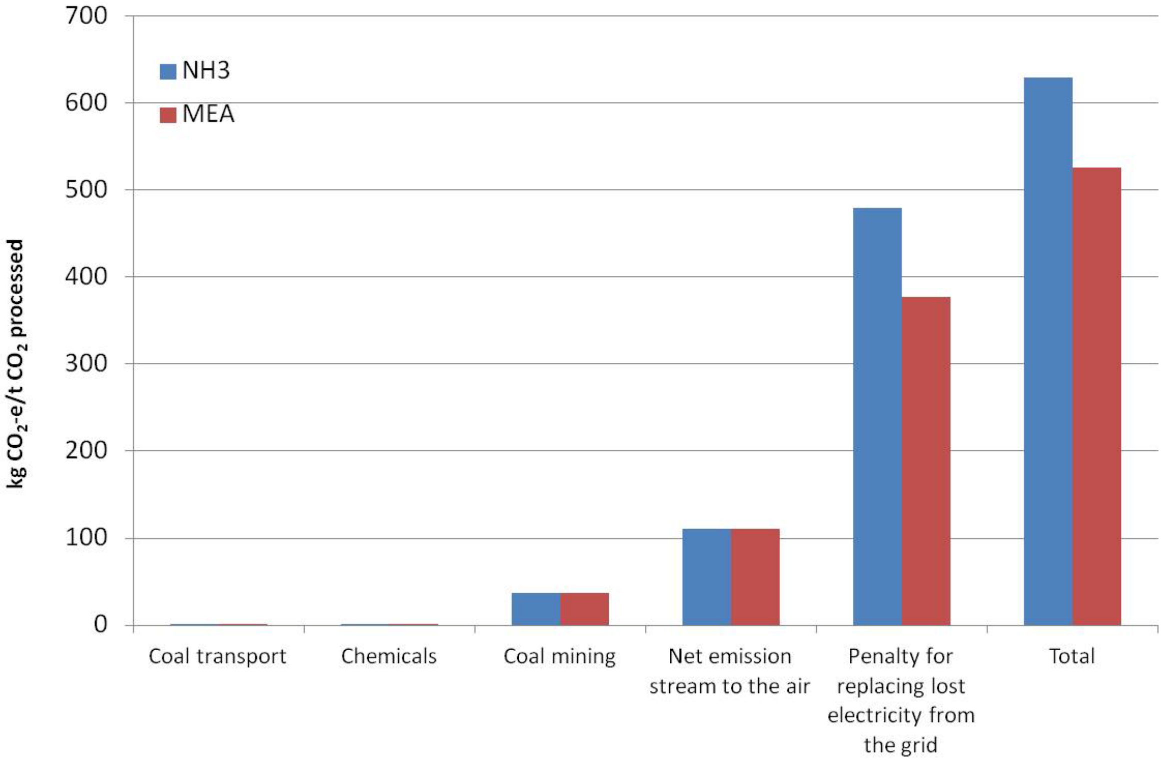


Figure 5: GHG footprint comparison of both processes with energy penalty calculated using current grid

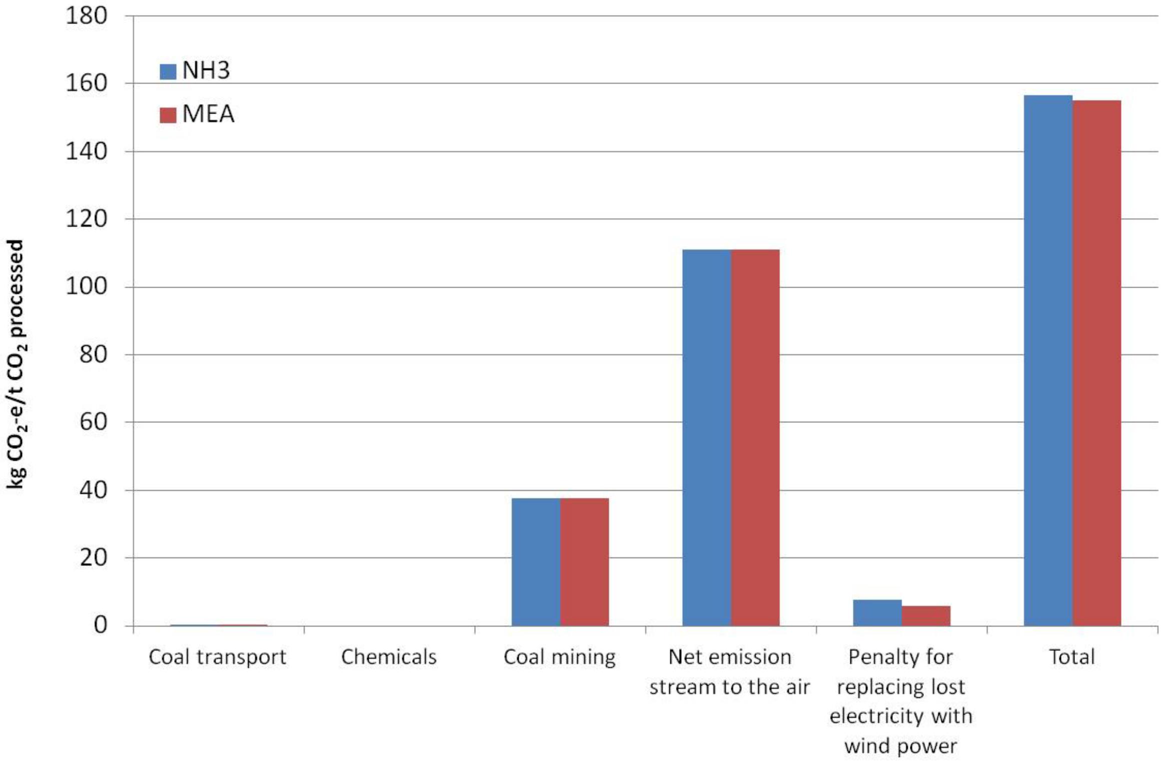


Figure 6: GHG footprint comparison of both process with energy penalty calculated using wind power

4.1 NH_3 Process

The total GHG emission is 629 kg CO_2-e for one tonne of CO_2 processed or captured. The majority (ca. 81%) of this total emission is due to the penalty for power lost in a plant used with PCC equipment followed by the (ca. 19%) final CO_2 emission stream to air after capture process. It is assumed that the power lost due to installation of PCC in plant due to equipment and power plant efficiency reduction, will have to come from the national grid.

The contribution from ammonia use is relatively negligible. However, it is to note that only make-up ammonia has been included in this estimate. If the initial inventory amount of NH_3 is significant, it should be included in the analysis. However, if the plant life is assumed 20+ years then the specific contribution from NH_3 becomes insignificant.

The key contributor to the penalty for this process is flue gas compression. This is a novel process configuration which aims to reduce ammonia losses and increase reaction kinetics all of which has not been tested and is difficult to determine whether these results match up with real life. It should also be noted that there are novel compression techniques being developed such as Ramgen which may be more suited to this application and give more efficient compression.

4.2 MEA Process

The total GHG emission is 525 kg CO_2-e for one tonne of CO_2 processed. The majority (ca. 77%) of this total emission is contributed from penalty due to power lost in a plant with equipment use of PCC plant. The emission component was (ca. 22%) is from the waste stream of the PCC plant directly to the air.

MEA chemical use is relatively minor similar to the NH3 process. However, it is to note again here that only make-up MEA has been included in this estimate. If the initial inventory amount of MEA is significant, it should be included in the analysis. However, if the plant life is assumed 20+ years then the specific contribution from MEA chemical use would then become insignificant.

The key contributor to the penalty for this process is CO2 stripping. As CO2 and MEA form a stronger chemical bond than that of CO2 and NH3 it is considerably larger than that of NH3 but is still not enough to offset the expense of the flue gas compression step in our novel process configuration for ammonia.

4.3 Comparison

Without a penalty for the differences in efficiency of the two PCC processes both the processes acheive the same result as the emissions are dominated by the 10% of uncaptured CO2 from the PCC plant. With the penalty included based on replacing lost power from the current NSW electricity grid then the total GHG footprint of NH_3 process is about 21% higher compared with that of MEA process. The differences in contributions from items are shown for both processes in Figure 5, Figure 6, Table 5 and Table 6.

The net energy requirement of the compressor in case of NH_3 process and blower in case of MEA process are different. This compression energy requirement is over an order of magnitude higher for NH_3 process compared with that of MEA process. On the other hand, the desorber unit of NH_3 process use less energy than that of the stripper unit of MEA process. Furthermore, the additional compression unit requires more energy for MEA process due to the low pressure of output CO_2 gas increased to 90 bar pressure before CO_2 liquefaction (output CO_2 gas is at 1.1 bar in case of MEA cf 9.5 bar in case of ammonia).

These electrical energy footprints do not affect the CO_2 emission significantly since the electrical energy comes from the power station fitted with PCC plant. The GHG contribution mainly comes from final outlet stream of CO_2 emission to the air and penalty CO_2 contribution due to loss of power with a PCC option. The penalty element is due to loss of power and replaced power from the national grid. The CO_2 recovery efficiencies are assumed to be the same between two processes (e.g. 90% CO_2 capture).

For overall reduction of GHG, both processes should focus on the loss of efficiency of power plant due to PCC. The desorber in case of ammonia based process is one of the main equipment that reduces the efficiency of power plant. Final outlet emission stream to air after capture for both processes is also significant. Thus if overall CO_2 recovery efficiency and the loss of power due to PCC is improved, the GHG footprint of both processes would reduce.

When comparing the technologies using a functional unit based on the primary production of unit of electricity the complicating penalties do not need to be added as it incorporated into the calculation. The results of this calculation are shown in Figure 7 and clearly show that the more efficient technology of the two studied is the MEA based process. With this comparison in mind it should be noted that while efficiency is important the ammonia based process may be more cost effective as it can potentially utilise the existing equipment to capture the CO2, NO2, and SO2 with minimal modifications whereas the MEA based process needs to have significant investment in downstream processing of fluegas to achieve low enough SO2 and NO2 levels for the process to work effectively.

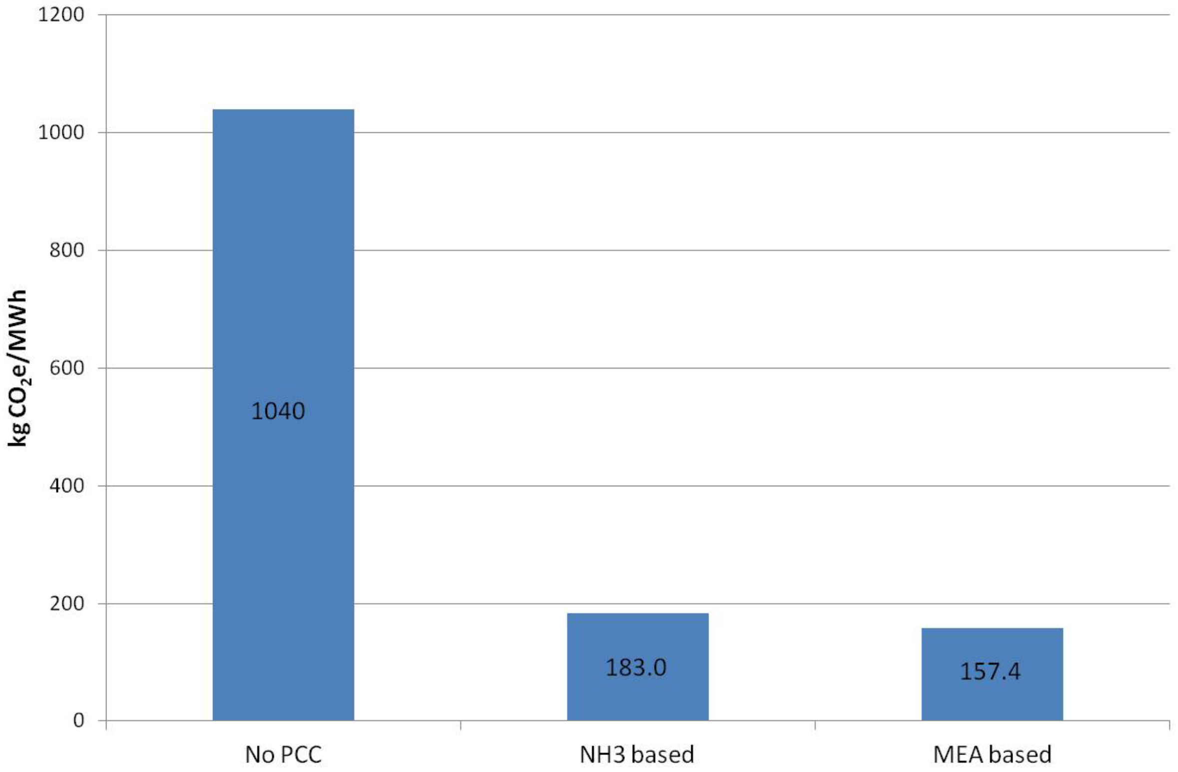


Figure 7: GHG footprint comparison of no PCC, MEA and NH_3 based processes on a per MWh basis

5 Sensitivity Analysis

The complete sensitivity analysis was not included due to the shortage of time for this study. The major contributing component on the nett GHG emission is the use of compressor for NH_3 based process. In comparison, the energy used for stripper is the main contributor for MEA based process. The sensitivity analysis may include the effects of the desorber in case of NH_3 based process and stripper in case of MEA based process.

The complete uncertainty analysis has not been undertaken due to shortage of time. This is a conceptual process with high uncertainty. There is an uncertainty on the inputs such as estimate of the electricity required to run equipments of PCC (e.g. motors for pumps etc). The input values are used as an average estimate derived from theoretical information and Aspen flowsheeting software based on mass and energy balances data. If these key inputs are varied by ±25%, the output results will be affected similarly for both processes.

The electricity data in the Australasian life cycle inventory database used within SimaPro software has some uncertainty. This will have some impact on the GHG footprint. The uncertainties of the effect of electricity used for two processes are similar since same electricity has been used in both processes.

Since all these uncertainties of the inputs for both processes are similar in nature, sensitivity analysis is likely to produce results with similar variation.

6 Conclusions

The total GHG emission was 629 kg CO_2-e for one tonne of CO_2 processed using NH_3 based process this is equivalent to 38.6% of all CO2 emissions from the process not being captured. In contrast, the total GHG emission was 525 kg CO_2-e for one tonne of CO_2 processed for MEA based process which is equivalent to 34.4% of all emissions from the process not being captured. Both of these emission factors were based on replacing lost electricity being input into the grid with an equivalent amount of electricity using the current NSW grid emission factor of 1.04kg CO2/kWh. If the penalty is calculated using electricity replaced using wind power for example then the emission factor for the NH3 and MEA processes become 157 kg CO_2-e /t CO_2 captured and 155 kg CO_2-e/t CO_2 captured respectively. What is lost in this approach is the cost of implementing wind power in sufficient quantities to overcome the lost power from the grid as a result of installing PCC. This has not been calculated or assessed in this report and could potentially form part of a future techno-economic analysis of options for PCC on the Australian grid.

When comparing the net GHG emission footprint of the two PCC processes to a power station without PCC it compared with a different functional unit to pick up the primary product value of electricity. The base case was reported to be 1.04 kg CO_2/kWh electricity sent out for power plant with no PCC unit with black coal. In comparison, the GHG footprint of the power plants with PCC units based on MEA is 0.18 kg CO_{2-e}/kWh and the GHG footprint based on NH_3 is 0.15 kg CO_{2-e}/kWh electricity sent out.

The results using all methods except maybe that of using windpower as the basis for the energy penalty clearly show that the more efficient technology of the two studied is the MEA based process. With this comparison in mind it should be noted that while efficiency is important the ammonia based process may be more cost effective as it can potentially utilise the existing equipment to capture the CO2, NO2, and SO2 with minimal modifications whereas the MEA based process needs to have significant investment in downstream processing of fluegas to achieve low enough SO2 and NO2 levels for the process to work effectively.

Ultimately in order to achieve reductions in CO2 emissions from primary energy sources such as power stations it is important not just to look at the life cycle efficiency but the overall cost to make those reductions.

7 Further work

Life cycle analysis is a useful tool for comparing technologies operating to produce the same products or outcomes. As the technology of applying post combustion capture to power stations is still new there is uncertainty in data being utilised for the study especially in the case of the ammonia based process in this study. As processes are developed and tested and more information becomes available then these life cycle analyses can give a more clearer indication of the environmental impacts of the processes especially with regards to other impact factors such as acidification, eutrophication and dust generation for example.

This study also highlights the need to look at better methods for comparison of CO2 reduction technologies. Utimately the reduction of CO2 emissions will be dependant on cost so with that it should be considered an important area of future study to look at comparative costs of CO2 reduction technologies and then this studies can be more useful in guiding industry and governments as to where is best to direct focus.

8 References

Australasian LCI (2013) Australian LCA data and data tools. (Accessed on 11/09/2013 from http://www.lifecycles.com.au/#!australian_data__tools/c1s7h).

EU (2011) CO2 Enhanced Separation and Recovery Report for European Commission, Seventh Framework Program Theme 5 - Energy Energy 2007.5.1.3: Advanced separation techniques Collaborative Project– GA No. 213569. 112p.

ISO 14044 (2006) Environmental management - Life cycle assessment - Requirements and guidelines. International Organization for Standardization, ISO, Geneva, Switzerland.

PRe (2013) Life Cycle Consultancy and Software Solutions, SimaPro Software. (Accessed on 27/08/2013 from http://www.pre.nl)

CONTACT US
t 1300 363 400
+61 3 9545 2176
e enquiries@csiro.au
w www.csiro.au

YOUR CSIRO

Australia is founding its future on science and innovation. Its national science agency, CSIRO, is a powerhouse of ideas, technologies and skills for building prosperity, growth, health and sustainability. It serves governments, industries, business and communities across the nation.

FOR FURTHER INFORMATION
Process Science and Engineering
Dr Nawshad Haque
t +61 3 9545 8931
e Nawshad.Haque@csiro.au
w www.csiro.au/people/Nawshad.Haque.html

---

[i] http://www.cansolv.com/en/cansolvsolvants.ch2