Coal Innovation NSW Grant

Feasibility assessment of Bioenergy with Carbon Capture and Storage (BECCS) deployment with Municipal Solid Waste (MSW) co-combustion at New South Wales (NSW) coal power plants

Project Number RDE493-37

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Executive Summary

This study aimed to address some of the challenges faced in relation to the contribution of coal-fired power generation to carbon dioxide (CO_2) emissions by investigating the potential for use of alternate low emissions technologies and fuels in conjunction with existing coal-fired generation. The project as funded by Coal Innovation NSW was to assess the technical and economic viability of co-combustion of coal, Municipal Solid Waste (MSW) and Commercial and Industrial (C&I) waste biomass in conventional coal-fired power plants in NSW. When biomass is involved in such co-combustion, it can be classed as a type of "Bioenergy with Carbon Capture and Storage" (BECCS), a negative emissions technology.

An assessment of the MSW and C&I waste in the first phase of the project revealed that it consists of many different types of combustible and non-combustible materials. Combustible materials include plastics (which are often non-biomass based), textiles (which are a combination of biomass and non-biomass derived) and biomass materials such as food waste, garden waste, paper and wood. Non-combustible materials include glass and metal. For this scoping study, only the wood and paper from MSW and C&I waste (hereafter referred to as Dry Combustible Organic Waste, DCOW) were considered for co-combustion due to their compatibility with the co-firing process. Food waste and garden waste usually contain too much moisture for easy co-firing and are better treated using other technologies (e.g. composting or dehydration).

The NSW power plants considered were Mt Piper, Eraring and Bayswater, chosen due to their suitability for co-combustion and relatively lower power plant age. Single plant-pipeline cases were examined at 0% and 10% co-firing levels, as well as a network case at 0% and 5% co-firing levels. The co-firing levels were constrained by waste availability. The network case joined the power plants to a connection point at Dunedoo, directing all CO_2 captured from the plants to an injection site in the Pondie Range Trough, Darling Basin.

The effect of 5% and 10% co-firing on the combustion cycle and exhaust gas was investigated via a combustion and trace element model developed by researchers from Imperial College London. The model assumed each fuel entered separately into the reactor (boiler) and produced its own flue gas which was subsequently combined. The combined flue gas pressure was set at 1 atm for both co-firing levels. Due to the inlet gas flow rate adjustment, temperature and gas compositions leaving both columns had relatively similar molar percentage, namely 14% for CO_2, 7% for H_2O, 4% for O_2, and 75% for N_2.

For a lower share of coal (that is higher rates of DCOW co-firing), more ash-forming elements are released, except for silica, due to the contribution of the waste wood. Trace elements are mostly emitted more from the higher share of coal than from the lower one. However, some elements, such as Pb, Cd, and As, show an increase in emissions as the share of coal is decreased. This indicates that the emission concentrations depend on the initial concentrations of both the coal and biomass. Further, the modelled concentrations for aggregated type 1 and 2 emissions from the co-firing plant are significantly higher than the emission limits in NSW, with Mn and V emissions being the largest contributors. This indicates that an aerosol precipitator is required to capture aerosols formed before entering the emissions stack. As NSW power plants already have an aerosol precipitator, the final emissions should be within the limits.

A life cycle assessment of a hypothetical 500 MW power plant in NSW with BECCS co-firing showed that direct emissions from combustion at the power plant was the largest contributor to global warming potential (GWP), followed by emissions attributed to coal procurement, and then emissions from the electricity generation for CO_2 compression. As the co-firing ratio increased and CCS was implemented, the life cycle CO_2 emissions decreased. DCOW co-firing at 10% without CCS only achieved a modest reduction of life cycle CO_2 emissions compared to typical coal-fired power generation, from 938 to 917 kg CO_2/MWh, whereas implementing CCS at a coal-fired plant reduced life cycle emissions to 253 kg CO_2/MWh. BECCS co-firing at 10% achieved further life cycle CO_2 emissions reductions to 181 kg CO_2/MWh (81% lower than unabated coal), which is comparable to some renewable energy sources such as solar PV. Increasing the co-firing ratio to 29.8% was found to deliver net-zero emissions. However, biomass availability limited the maximum co-firing ratio to 10.5%.

A techno-economic assessment of all the cases revealed that the energy penalty and levelised cost of electricity (LCOE) increased with co-firing ratio, while the cost of CO_2 avoidance (COA) decreased. The cases with the lowest net emissions intensity were the single pipeline 10% co-firing cases, achieving a net emissions intensity of 0.02 tCO_2/MWh. The lowest cost BECCS configuration was achieved by the 5% co-firing network case at an LCOE of $133.8/MW, COA at $118/$tCO_2$ avoided and emissions intensity of 0.07 tCO_2/MWh.

The investigations reported in this study provide strong evidence that BECCS can significantly reduce CO_2 emissions. Further research considering additional sources of biomass in NSW to supplement wood waste and further technical study into the effects of MSW on the co-firing system may unlock greater opportunities to integrate BECCS in the NSW electricity generation pool. This should include consideration of other combustible MSW (such as textiles and garden waste, preferably after conversion to a dry combustible material through, for example, composting or dehydration) or other combustible wastes (such as agricultural waste) that were not included in this study. Current efforts towards a circular economy may lead to more competition for the available waste; however, this may also increase the availability of cleaner end-life organic materials, which would facilitate BECCS. Additionally, detailed life cycle assessments of the proposed single pipeline and network cases are recommended to more accurately assess if BECCS should form part of future policy to meet emissions reduction targets.

Lay Summary

Burning coal to produce electricity is one of the main contributors of carbon dioxide emissions to the atmosphere. This study aims to find out if it is practical and cost-effective to reduce those emissions in NSW by burning waste materials along with the coal, separating the carbon dioxide from the rest of the combustion gases and storing the carbon dioxide deep underground

Municipal Solid Waste (MSW), or rubbish, is a combination of many different materials, many of which cannot be burned (such as glass and metal), but also many that can burn. The materials this study is interested in are dry materials that were derived from plants, such as wood and paper waste, as they are easier to burn in a power plant and can be separated more easily than other wastes. When wood and paper are burned, the carbon in them just returns to the atmosphere because it was absorbed from the air when the plants were growing, but if that carbon is separated and stored deep underground, then the amount of carbon dioxide in the atmosphere is reduced. This technology is known as "Bioenergy with Carbon Capture and Storage", or BECCS.

For this study, BECCS involves burning coal along with wood and paper waste to generate electricity, while separating the carbon dioxide, transporting it via pipeline, compressing and storing it deep underground in western NSW, at a well site in the Darling Basin: Mena Murtee-1 in the Pondie Range Trough. We consider implementing this type of BECCS at the three younger coal power plants in NSW where wood and paper could be easily burned: Mt Piper, Eraring and Bayswater. We also consider burning different amounts of waste at each power plant, but even if all available wood and paper waste in NSW was used, it would only amount to about 5% of the fuel burned in those three plants.

According to this study, burning paper and wood waste alongside coal reduces the amount of carbon dioxide added to the atmosphere, but produces more ash than burning coal alone. This means it will be necessary to add extra equipment to catch the extra dust before it is released to the atmosphere. If one-tenth of the fuel is wood and paper, carbon emissions are only slightly reduced (less than 3%), but if carbon capture and storage is also implemented (thereby implementing BECCS) then the power plant will only emit about one-fifth of the emissions of a normal coal plant over its whole life, which is similar to the overall emissions of electricity produced by solar panels. BECCS can also completely offset the carbon emissions from coal if more than a third of the fuel burned is wood and paper waste, thereby achieving negative emissions. Although the cost of getting rid of the carbon dioxide becomes lower as more waste is burned, the cost of the electricity is increased, because less electricity is produced.

This study concludes that BECCS can help significantly reduce carbon emissions in NSW. Still, it is important to consider other waste sources (for example textiles, garden waste, agricultural waste), as availability of waste is a strong limitation for further use of this technology.

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List of Abbreviations

AEMO	Australian Energy Market Operator
ALCAS	Australian Life Cycle Assessment Society
AWT	Alternative Waste Treatment
BECCS	Bioenergy with Carbon Capture and Storage
C&D	Construction and Demolition Waste
C&I	Commercial and Industrial Waste
CCS	Carbon Capture and Storage
CINSW	Coal Innovation New South Wales
CO_2	Carbon Dioxide
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
COA	Cost of CO_2 Emissions Avoided
CR	Co-firing Ratio
CV	Calorific Value
DCOW	Dry Combustible Organic Waste
EASAC	European Academies Science Advisory Council
EI	Emissions Intensity
EPA	Environment Protection Authority
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulphurisation
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	Higher Heating Value
ICCSEM	Integrated Carbon Capture and Storage Economic Model
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organisation for Standardisation
ISP	Integrated System Plan
LCI	Life Cycle Inventory
LCOE	Levelised Cost of Electricity
LGA	Local Government Area
LHV	Lower Heating Value
MEA	Monoethanolamine
MRF	Materials Recovery Facility
MSW	Municipal Solid Waste
NEM	National Energy Market
NO_x	Oxides of Nitrogen (nitric oxide [NO], nitrogen dioxide [NO_2])
NSW	New South Wales
PEPs	Protection of the Environment Policies
QLD	Queensland
REZ	Renewable Energy Zone
SO_x	Oxides of Sulphur (sulphur dioxide [SO_2])
UNFCC	United Nations Framework Convention on Climate Change
UNSW	University of New South Wales
VIC	Victoria

1 Introduction

1.1 Background

Current and future conventional coal power generation in NSW faces significant challenges. These include the need to identify safe and economically effective ways to respond to the climate change challenge, which is expected to require the use of lower carbon, but often challenging, fuels. It is critical for the NSW economy and NSW power generation that synergies between new low-cost sources of fuel and conventional coal for power plants are explored. In particular, there is significant potential for co-combustion or combustion systems to use waste or marginal fuels such as municipal solid waste (MSW), wood-related wastes, and construction industry and agricultural wastes. Nevertheless, the fact remains that not every material present in these wastes is necessarily combustible, and this should be taken into consideration when selecting a suitable source of waste.

The current project assessed the technical and economic viability of reducing emissions from a representative conventional coal power plant within NSW through co-combustion with wood and paper sourced from MSW and commercial and industrial (C&I) waste, otherwise referred to as dry combustible organic waste (DCOW), coupled with the emissions reductions gained through implementation of CCS. This coupling can be classed as a type of "Bioenergy with Carbon Capture and Storage" (BECCS), that is, the use of sources of biomass for power generation combined with the capture and geological sequestration of the CO_2 from the combustion of biomass. As the carbon from the combusted biomass would have originated from atmospheric CO_2, implementation of BECCS results in a net flow of CO_2 from the atmosphere to geological storage, also referred to as negative emissions. The outcomes from the project include an assessment of the technical and economic feasibility of DCOW co-combustion and CCS that could facilitate the uptake of low coal emissions technologies.

1.2 Project Aims and Objectives

The objectives of the project included:

1. Identifying potential networks for BECCS in NSW through mapping of existing and proposed MSW sources, coal power plants and geological storage sites in NSW.
2. Understanding the effects of co-combustion of waste on the combustion cycle and exhaust gas of a coal power plant in NSW, including at different ratios.
3. Assessing the greenhouse gas and CO_2 reduction potential of BECCS deployment with DCOW through a life cycle assessment, as well as ascertaining the opportunities for negative emissions.

4. Evaluating the economic viability of BECCS in NSW; including the impact on the levelised cost of electricity ($/MWh_e$). This analysis incorporates sensitivity analysis to understand the effects of waste and transport costs on the feasibility of the CCS.

1.3 Milestones and Performance Measures

The aims and objectives were achieved as summarised in Table 1-1.

Table 1-1: Project Milestones summary table

Milestone ID	Milestone Title	Status (%)	Relevance to project and achievement
1.1	Review of existing biomass MSW sources, coal power plants and geological storage sites in NSW	100%	The analysis in this report is underpinned by the correct identification of the potential for the three stages of BECCS: MSW and C&I waste biomass sourcing, co-combustion + capture and geologic storage. A database of waste sources and power plants in NSW was generated and the information used in the subsequent tasks of this Project.
1.2	Identify suitable biomass sources and coal power plants	100%	Wood and paper sourced from MSW and C&I waste were identified as the most suitable biomass (DCOW). The key coal NSW power plants of Mt Piper, Bayswater and Eraring were identified as being capable of co-combusting DCOW due to their age and location to nearby landfill sites. These sources and locations were the basis for the analysis in the subsequent Project tasks.
1.3	Develop preliminary waste and CCS network design	100%	Key policy and regulatory legislation relating to CCS and Municipal Solid Waste was summarised and the effects on BECCS were evaluated. Preliminary network maps for landfill DCOW sources for the Mt Piper, Bayswater and Eraring coal power plants and a CO_2 pipeline transport network to the selected geological storage site of Darling Basin (Pondie Range Trough) were developed. These were used in latter stages of the Project for LCA and Techno-Economic Analysis.
2.1	Literature review of co-combustion technologies	100%	Elements of concern from MSW co-combustion were identified and possible synergies between waste streams and coal clean-up systems were investigated. The relationships between fuel composition, carbon intensity and electricity price were quantified and the additional value, if any, of fuel flexible power plants to the energy system was identified.

2.2	Develop black-box model or correlation of the fuel-flexible combustion data obtained in Task 1	100%	Different ratios of DCOW (as wood waste) to coal were simulated in combustion. The ratios selected were 5% and 10%, by DCOW weight based on the total amount of waste available for BECCS identified in Task 1. The impact of varying fuel compositions on exhaust gas composition, clean-up equipment and the carbon capture process were evaluated. These form the basis of key recommendations of this Project.
3.1	Undertake an evaluation of emissions reductions of the co-combustion MSW and coal at a typical NSW coal power plant	100%	A life cycle assessment for BECCS, with particular focus on DCOW co-combustion with coal was carried out. The life cycle inventory and modelling for the LCA was completed for a typical coal-fired power plant in NSW, as well as one implementing the BECCS strategy identified in Task 1.
4.1	Develop cost database for the MSW handling in NSW. Update relevant cost	100%	A cost database for coal power plants, biomass co-firing, CO_2 capture, pipeline network transport and geologic storage, was developed. These costs underpinned the analysis for Milestone 4.2.
4.2	Economic assessment of capital and operating cost, levelised cost of electricity (LCOE) for a typical 500 MW bituminous coal power plant in NSW with MSW co-combustion and CCS	100%	The economic assessment determined the LCOE and COA for the different scenarios including BECCS, developed in Task 1. Key economic parameters affecting these costs were identified.
5	Final Report	100%	This final report summarises the methodology, analysis, findings and recommendations of this study.

2 Task 1: Existing and proposed DCOW sources, coal power plants and geological storage sites in NSW

2.1 Energy Production and Waste Management in NSW

Electricity production in New South Wales (NSW) is dominated by black coal-fired sources contributing to 81% total electricity production (Department of the Environment and Energy, 2018b) and 97% of greenhouse gas emissions from the sector (Clean Energy Regulator, 2019). The current coal-fired power assets in NSW have an average technical life of 37.6 years, with many assets nearing the end of their technical lifetime of 40-50 years (Energy Networks Australia, 2019). As a result, in order to meet not only energy demand but also NSW's net-zero emissions target by 2050, existing coal-fired assets must be evaluated in terms of viability for refurbishment or else will face closure.

One process of power generation that offers NSW a potential companion to coal combustion while simultaneously reducing CO_2 emissions is called 'Bioenergy with Carbon Capture and Storage' (BECCS). BECCS refers to power generation through combusting biomass as a substitute for fossil fuels and reducing resulting CO_2 emissions in the flue-gas by utilising carbon capture and storage (CCS). The biomass used for BECCS can be obtained from any of a variety of sources, such as dedicated biomass crops or from waste sources (e.g. agricultural waste, MSW, commercial and industrial waste, etc.). Because the biomass used as fuel for combustion has already extracted CO_2 from the atmosphere through photosynthesis, and the vast majority (up to around 90%) of CO_2 in the flue-gas may be captured and sequestered, BECCS is considered a negative greenhouse gas (GHG) emissions technology. Negative emissions technologies are recognised by the IPCC and UNFCCC as having the potential to play an important role in maintaining atmospheric CO_2 concentration at an acceptable level (EASAC, 2018).

A key consideration in assessing the viability of BECCS is the source of biomass. A desirable source is MSW. Policies such as the *Protection of the Environment Operations Act 1997* introduced standards that have necessitated landfill facility upgrades. This has dramatically increased the cost of waste disposal for local governments. With the population of NSW expected to grow to 8.2 million by 2021, the amount of waste for processing will increase to approximately 20 million tonnes. The NSW Environment Protection Authority (EPA) has set targets for waste diversion from landfill at 75% and as such local governments are facing pressure to introduce alternatives to process MSW. Thus, BECCS with MSW could be an alternative waste management solution for local governments that might be compatible within the existing business networks in the waste management sector.

A possible waste to energy production to CO_2 storage network is shown in Figure 2-1. Details of the specific landfill sites, power plant sites and CO_2 storage sites are presented later in this report.

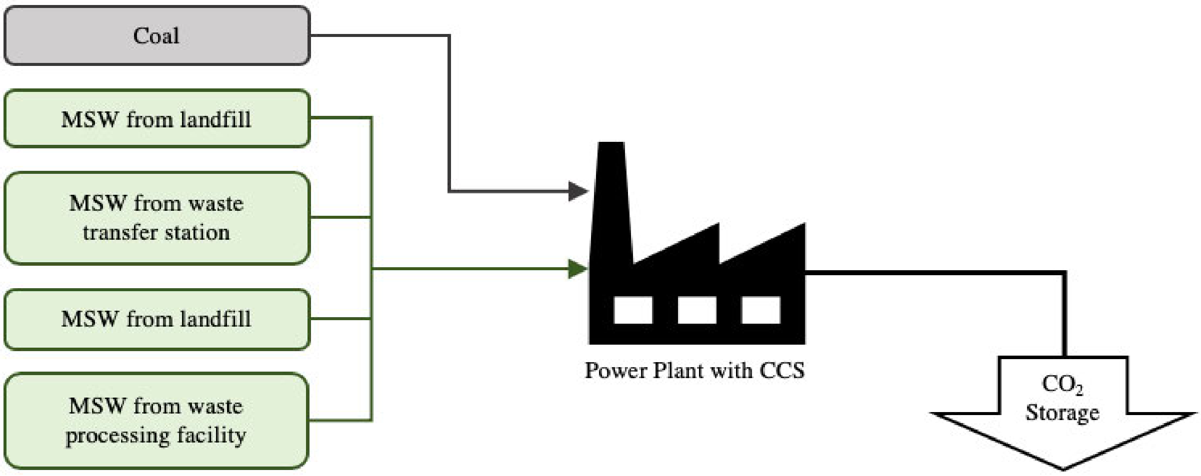

Figure 2-1: Schematic of a possible MSW network configuration in which multiple MSW sources are diverted to one or more BECCS power plants and the CO_2 is captured and sequestered.

2.2 Tasks 1.1 and 1.2: Mapping of existing and proposed MSW sources, coal power plants and geological storage sites in NSW

2.2.1 Co-combustion options

Internationally, BECCS has already shown promise as a commercially viable form of power generation. There have been around 20 full-scale power plants utilising BECCS, located in North America, Europe, and Japan, with all currently operating BECCS projects being implemented at ethanol production facilities (Stavrakas, Spyridaki and Flamos, 2018). Although there have been previous trials of biomass co-firing in NSW, no BECCS plants have so far been implemented in NSW, or Australia for that matter. However, the technical and commercial viability of BECCS is heavily dependent on the characteristics of the fuel sources. Selecting a fuel source involves trying to maximise the reduction in greenhouse gases while maintaining a high enough heating value. The selection of the combustion technology is dependent on both the fuel source(s) and the features of the existing coal-fired power assets.

Although power plants dedicated to biomass combustion are being constructed, the core boiler technology in dedicated BECCS is very similar to that used in existing pulverized coal (PC) power plants. This principle has driven the research behind “co-combustion”; the act of firing coal and biomass together as a blended fuel. Co-combustion possesses significant potential, because retrofitting existing plants with biomass combustion technologies requires lower capital expenditure than constructing a dedicated plant. Additionally, co-combustion allows some flexibility in the proportions of coal and biomass used to fire the power plant. This means that as biomass processing becomes more efficient and boiler technology improves (i.e. to deal with corrosive biomass combustion products), plants should be able to allocate an increasing proportion of their feed to biomass. It also enables the power plant to maintain its production by increasing coal firing when biomass is in short supply.

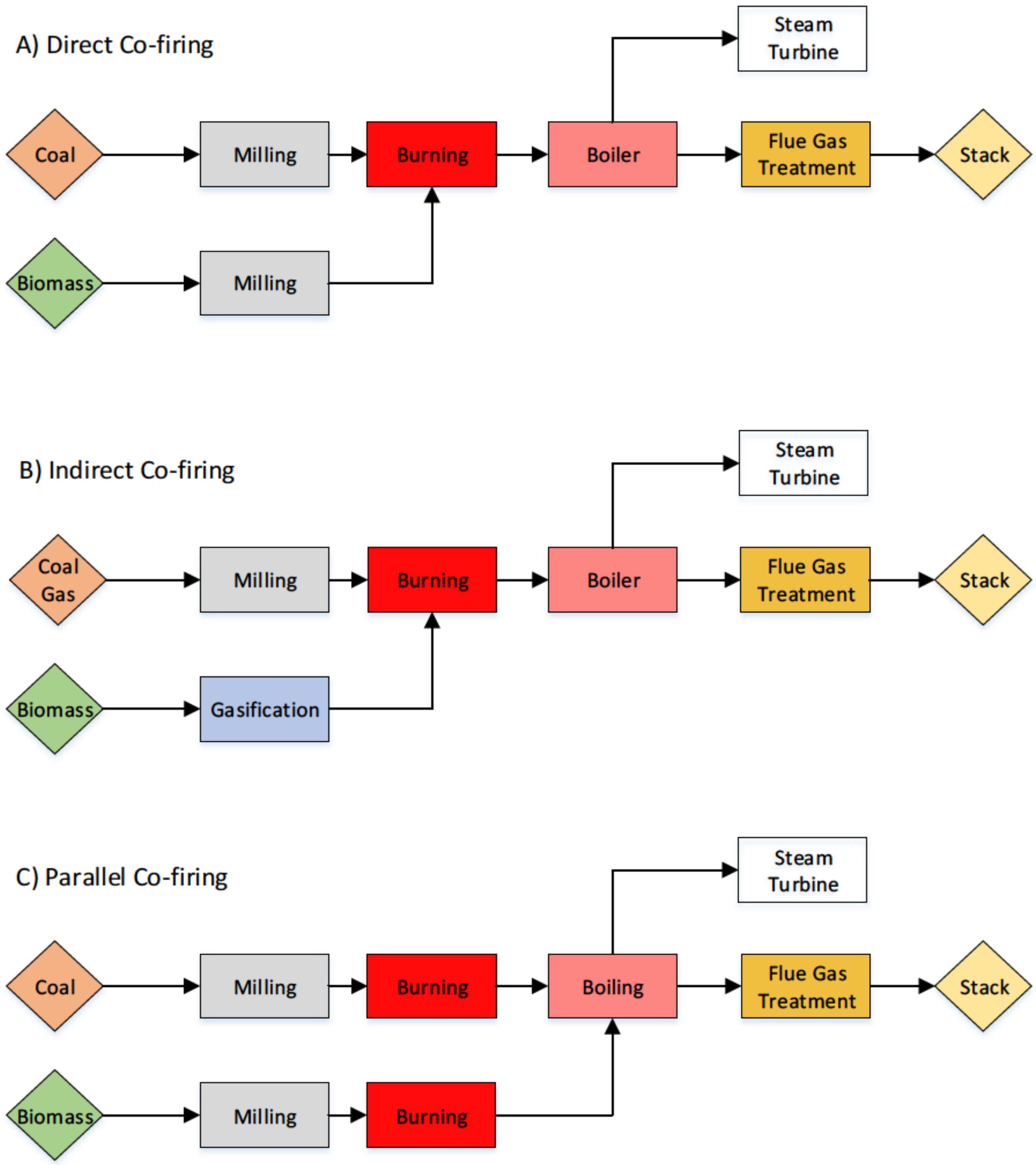

Figure 2-2: Flow chart showing the differences between A) direct co-combustion, B) indirect co-combustion, and C) parallel co-combustion (adapted from Agbor, Zhang, & Kumar, 2014)

Co-combusting biomass with coal follows one of three methods: direct co-combustion, indirect co-combustion, and parallel co-combustion (Figure 2-2). During *direct co-combustion*, biomass is milled either together or separately (as shown) from the base fuel (predominantly pulverized coal, PC) and combined in a concentration of approximately 3-5% (w/w). The coal-biomass mixture is transferred to the furnace, where the mixture is directly combusted. *Indirect co-combustion* involves the pyrolysis and gasification of biomass separately from the base fuel to produce syngas, which is subsequently fired with natural gas or gasified coal. *Parallel co-combustion* isolates the preparation, feeding, and combustion activities of biomass from the coal-boiler, with the steam generated from both boilers used to generate electricity in the steam turbine (Koppejan, Loo and Loo, 2012; Agbor, Zhang and Kumar, 2014).

The most common application of the three co-combustion methods is direct co-combustion. There are currently 230 operating power plants that utilise co-combustion for power generation, with the majority employing direct co-combustion (Jaap Koppejan., 2017). While many existing pulverized coal (PC) boilers require minimal modification to enable biomass co-combustion (Wieck-Hansen, Overgaard and Larsen, 2000; Savolainen, Savolainen and Kati, 2003; Agbor, Zhang and Kumar, 2014), it does incur efficiency losses due to increased ash formation, slagging and fouling.

2.2.2 NSW coal power plants with the capability to co-combust with MSW

As shown in Table 2-1, all the coal-fired power plants in NSW rely on pulverised coal boilers and hence may be suited to either direct co-combustion or parallel co-combustion. Power plant age is a key consideration in determining whether modifications are economically viable for the plant boiler. With the Liddell Power plant scheduled for closure in 2022 it is probably not financially viable to undertake modifications on this plant. Similarly, the Vales Point power plant with an age of 41 years is unlikely to undergo an upgrade as it has already exceeded the accepted average economic life time of a coal-fired power plant of 40 years (Stewart, 2017).

Hence, for this study, the NSW power plants assessed for BECCS were Mt Piper at an age of 27 years, Eraring at an age of 37 years and Bayswater at an age of 35 years. The analysis considered refurbishment and upgrade of these plants. Rather than opting for direct co-combustion which would require further refurbishment of the boilers than what would be required to extend their life (i.e. to deal with corrosion issues), a parallel co-combustion configuration was considered. This also allows this scoping study to explore higher co-firing levels.

Table 2-1: Existing and proposed coal-fired power plants in NSW and their characteristics (Brown *et al.*, 2006; Department of the Environment; ACIL Allen, 2015; AEMO, 2018, 2019; Clean Energy Regulator, 2019)

Facility name	Bayswater power plant	Liddell power plant	Mt Piper power plant	Eraring power plant	Vales Point "B" power plant
Commencement year	1984	1971	1992	1982	1978
Operator	AGL Energy Limited	AGL Energy Limited	Energy Australia Holdings Limited	Origin Energy Limited	Sunset Power International Pty Ltd
Boiler type	Combustion	Combustion	Combustion	Combustion	Combustion
	Steam sub-critical	Steam sub-critical	Steam sub-critical	Steam sub-critical	Steam sub-critical
	Pulverised coal	Pulverised coal	Pulverised coal	Pulverised coal	Pulverised coal
Condenser cooling	Natural draft cooling towers	Custom-built lake	Evaporative cooling towers	Natural draft cooling towers	Evaporating cooling towers
Cooling medium	Fresh water (Hunter River)	Salt water (Lake Macquarie)	Fresh water (Cox River)	Fresh water (Hunter River)	Salt water (Lake Macquarie)
Number of units	4	4	2	4	2
Unit size (MW)	660	500	700	720	660
Max rate of change per unit (MW/min)	140	110	25	25	20
Nameplate capacity (MW)	2640	2000	1400	2880	1320
Electricity production (GWh)	0	0	0	0	0
Auxiliary load (%)	6.0	5.0	5.0	6.0	5.0
Thermal efficiency HHV (%)	35.9	33.8	37.0	35.4	35.4
Heat rate (GJ/MWh)	9.46	10.14	9.27	9.55	9.69
Emission intensity (t CO2-e/ MWh)	0.88	0.92	0.87	0.87	0.86
Service status	In service	Announced withdrawal	In service	In service	In service
Closure date	2035	2022	TBA	TBA	2028/29
			Fuel properties		
Primary fuel	Black coal	Black coal	Black coal	Black coal	Black coal
C (%)	53.5	49.7	59.3	59	58.2
H (%)	3.5	3.3	3.7	3.7	3.7
N (%)	1.2	1.1	1.4	1.2	1.2
S (%)	0.5	0.5	0.5	0.4	0.4
O (%)	6.4	6.3	6.1	6.6	6.3
Ash (%)	24.7	30.4	21.2	21	22.2
Moisture (%)	10.1	8.8	8	8.2	8
Calorific value (MJ/kg)	22.4	20.9	24.7	24.3	23.8

2.2.3 Composition of waste in NSW

MSW and C&I waste are desirable biomass feed sources for co-combustion due to their potential to contribute to overall waste reduction in NSW in addition to the primary goal of emissions reduction in BECCS. In order to be a suitable and viable source for BECCS, waste must meet several key criteria such as providing a high concentration and volume of combustible material in convenient locations for transport to the power plants considered. These criteria are important in terms of the long-term viability of BECCS, and in terms of keeping electricity generation costs and carbon emissions as low as possible.

Another factor important in selecting a waste biomass feed source for co-combustion is its quality and hence composition. The characteristics and volumes of NSW waste generation in 2017 are summarized in Figure 2-3 based on the National Waste Report 2018 database. As shown in Figure 2-3, in 2017, there were 18,240,725 tonnes of total waste in NSW across 3 source streams, among which MSW accounted for 29% of all the waste generated in NSW with the remaining 71% comprised of C&I waste and construction and demolition waste (C&D) (Australian Government, 2018).

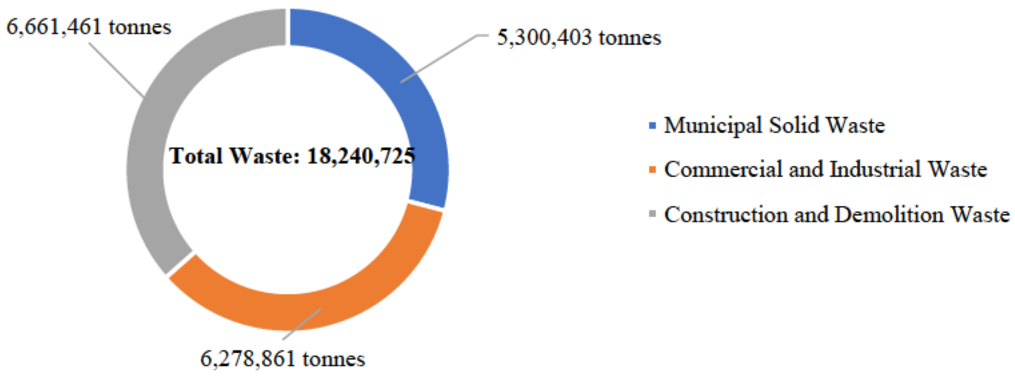

Figure 2-3: NSW total waste composition

A breakdown of the composition of MSW in NSW into different materials is shown in Figure 2-4, comprising 73% of combustible waste (categories 1-9) and 27% non-combustible waste (categories 10-11). A breakdown of the composition of C&I and C&D wastes in NSW into different materials is shown in Figure 2-5. A high proportion of C&D waste (94.1%) is non-combustible and hence ineligible for use in BECCS (Figure 2-5B). Therefore, the waste of interest is C&I waste comprising of 61% of combustible waste (categories 1-9) and 39% non-combustible waste (categories 10-11) as shown in Figure 2-5A.

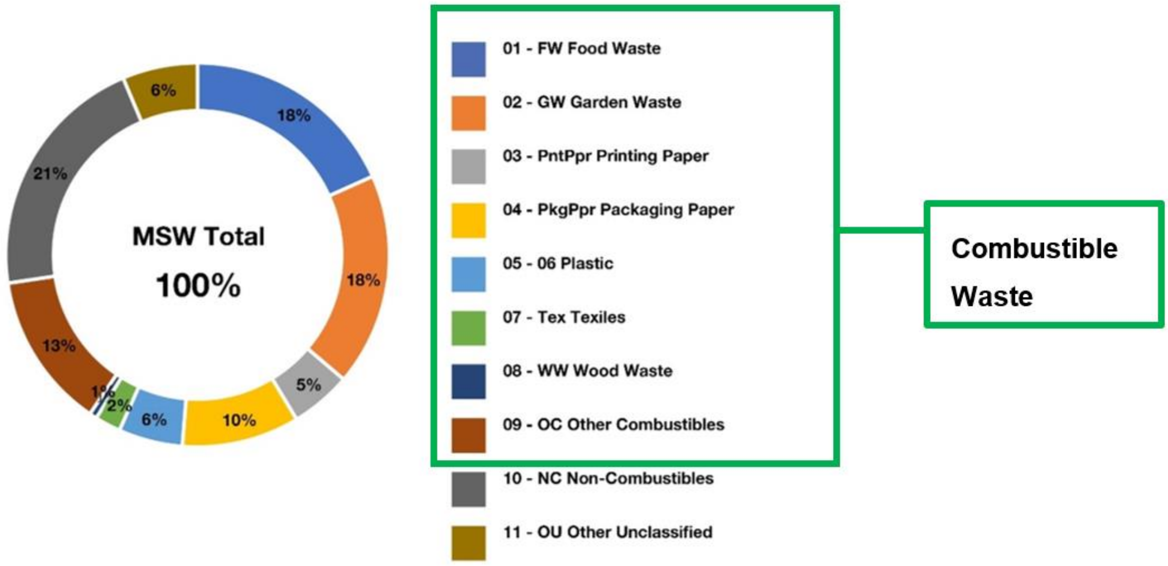

Figure 2-4: Breakdown of MSW into waste categories

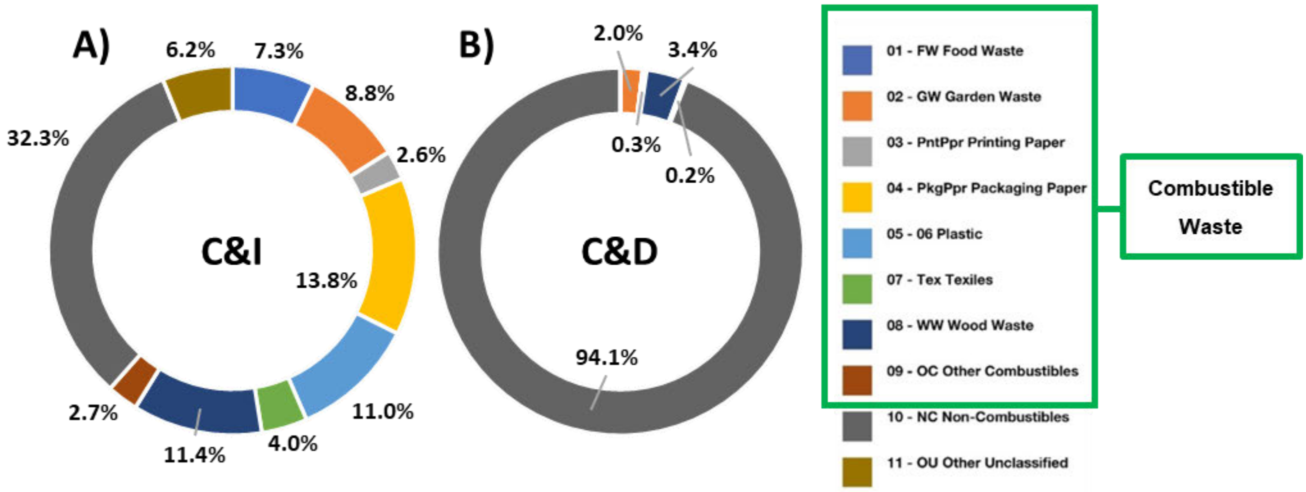

Figure 2-5: Waste category breakdown of A) C&I Waste and B) C&D Waste

2.2.4 Municipal solid waste sources in NSW

MSW as defined in the National Waste Report is mainly generated by households and local government operations (Australian Government, 2018). Thus, the population distribution as shown in Figure 2-6 becomes the key factor in determining MSW supply in the different geographic locations. Local government areas (LGAs) form the fundamental unit of the NSW MSW sources across 129 LGAs. Based on data from the 2016 Australian Census (Australian Bureau of Statistics, 2016) and the 2019 Office of Local Government NSW (Office of Local Government, 2019), the population has shown a significant growth in major urban centres in and around the Great Metropole Sydney area between 2016 and 2019. The Great Metropole Sydney accounted for 64% and 68% of the NSW population in 2016 and 2019, respectively.

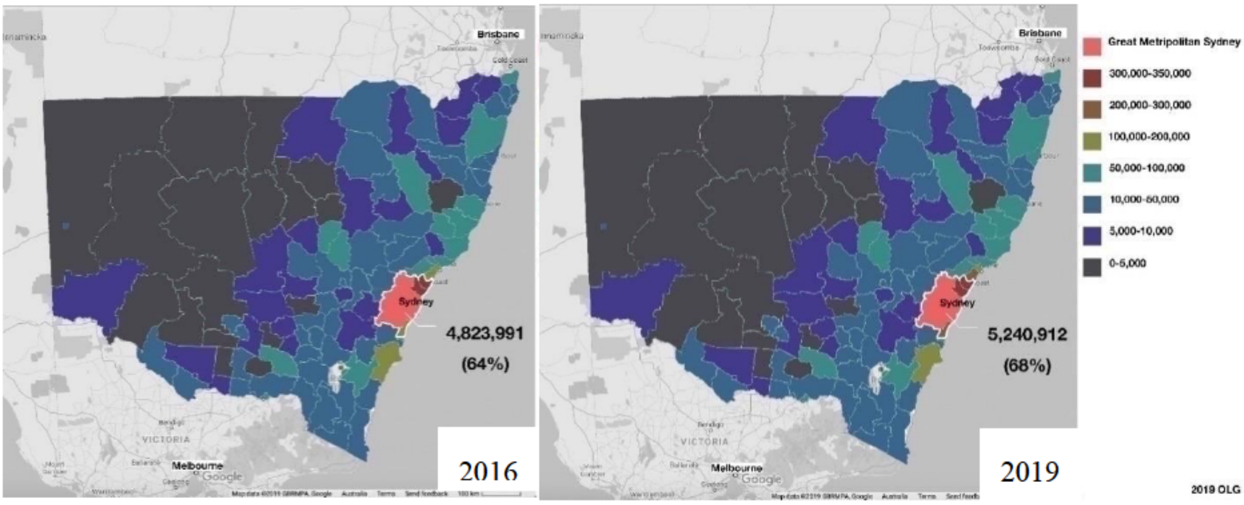

Figure 2-6: NSW population distribution in 2016 and 2019

Due to confidentiality and commercial sensitivity of landfill processing capacity registered under EPA licenses, landfill capacity data is not publicly available. Thus, the key MSW sources were estimated from the waste volumes generated across LGAs forming key landfill clusters. The volume generated in each LGA was estimated from its population and the average MSW generation volume per capita outlined in the National Waste Report 2018, which annually is 560 kg per capita in Australia (Australian Government, 2018). These estimates were further reduced into 10 major clusters based on the Statistical Area Level 4 of the Australian Statistical Geography Standard system as shown in Table 2-2 and Figure 2-7 (Australian Bureau of Statistics, 2019).

Table 2-2: Reduced set of landfill clusters for NSW

LGA cluster name	Number of LGAs
Greater Metropole Sydney Cluster	35
Illawarra Cluster	4
Hunter and Newcastle Cluster	9
Richmond-Tweed Cluster	6
Mid-North Coast Cluster	4
Coffs Harbour – Grafton Cluster	3
Central West Cluster	12
Riverina, Murray and Capital Region Cluster	29
Far West and Orana Cluster	13
New England and North West Cluster	12

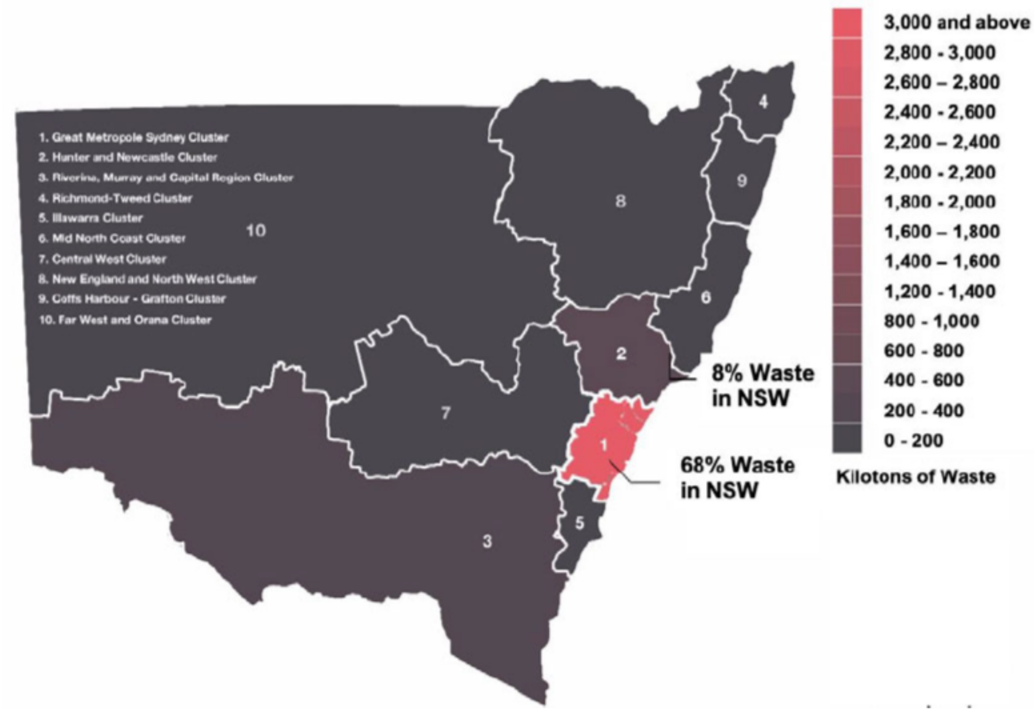

Figure 2-7: Reduced set of landfill clusters for NSW showing annual volume of MSW for disposal, estimated for 2019

The annual MSW volume of each key landfill cluster is displayed in Table 2-3 with the landfill cluster name and estimated annual MSW volume generated inside each area, which is further divided into combustible and non-combustible waste. The calorific value of MSW, in terms of its Lower Heating Value (LHV) is estimated to be around 16.8 MJ/kg (Pour, Webley and Cook, 2018a).

Table 2-3: Top 10 key landfill clusters in NSW annual volume MSW for disposal, estimated for 2019.

LGA cluster name	MSW disposal only (tonnes)	MSW disposal + recycle (tonnes)	Source stream	Combustible (73%)	Non-combustible (27%)
Great Metropole Sydney	997,869	2,700,116	MSW	728,444	269,425
Hunter and Newcastle	120,822	326,930	MSW	88,200	32,622
Riverina, Murray and Capital Region	95,517	258,458	MSW	69,727	25,790
Richmond-Tweed	46,679	126,308	MSW	34,075	12,603
Illawarra	46,343	125,299	MSW	33,820	12,513
Mid North Coast	42,047	113,774	MSW	30,694	11,353
Central West	39,947	108,091	MSW	29,161	10,786
New England and North West	35,380	95,734	MSW	25,827	9,553
Coffs Harbour	26,446	71,560	MSW	19,306	7140
Far West and Orana	22,291	60,317	MSW	16,272	6,019

Hence, LGA clusters of Great Metropole Sydney and Hunter and Newcastle were selected as sources of biomass for the proposed BECCS network due to their proximity to the coal-fired power plants selected for this study and the fact that 76% of all MSW in NSW is located in these regions. With major

NSW coal power plants being located around the North and West of the Great Metropole Sydney area, it can be assumed that the main MSW supply will be diverted from key landfill clusters nearby using existing transportation networks and highways. The key transport networks connecting landfill clusters and the selected power plants is shown in Figure 2-8 including the New England Highway and Great Western Highway connecting the Greater Metropole Sydney LGA to the Bayswater and Mt Piper power plants respectively. The M1 connects Sydney to Eraring while the M15 connects the Hunter and Newcastle LGA to Bayswater. It should be noted that a large cluster of transfer stations are located in the North West Region. These stations are not representative of large volumes of waste being directed from the region but act as a collection point for waste from rural LGAs.

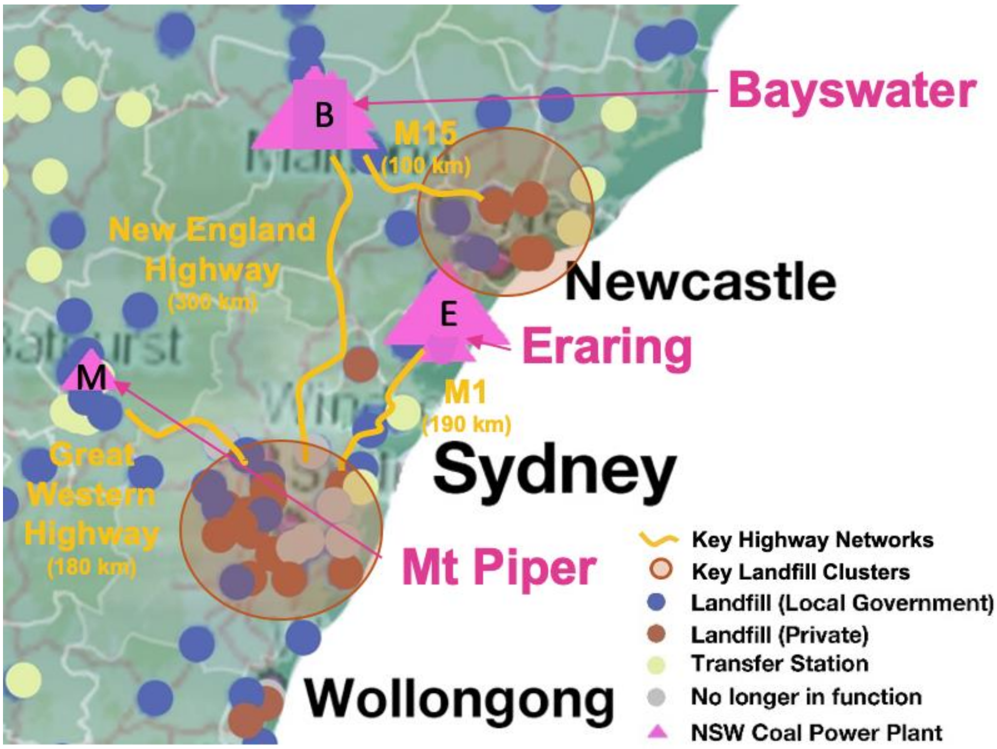

Figure 2-8: MSW site and coal-fired power plant road networks

2.2.5 Waste in NSW for BECCS use

Key considerations in determining the biomass feedstock for BECCS use are the energy intensity, emissions potential of various feedstock options, incidence of usage and waste availability. Distinct categories of waste include domestic waste (food waste, garden waste), paper (printing paper, packaging paper), plastic (packaging plastic, other plastic), textiles and wood. Textiles were not considered suitable as BECCS feedstock due to their low availability and the fact that not all textiles are biomass derived. While there is a high volume of domestic food and garden waste, the high moisture content ranging from 46.5-80.9% (Office of the Renewable Energy Regulator, 2001) and uncertainty of composition does not make it an ideal candidate for BECCS. Since the majority of plastic currently comes from non-renewable sources and can produce significant amounts of toxic emissions including dioxins if burned without sufficient controls (Verma *et al.*, 2016), it was not deemed to be suitable for BECCS. While unsorted MSW could be suitable for BECCS, this option was not explored in this study due to lack of composition data, the impact of unsorted MSW on burning efficiencies and modelling limitations.

Wood and its variations, mainly sawdust and wood pellets have been most commonly used in commercial and laboratory based trials of co-combustion around the world (Hughes and Tillman, 1998; Savolainen, Savolainen and Kati, 2003; Bhuiyan *et al.*, 2018; Guo and Zhong, 2018). In this study, wood fractions in MSW and C&I were therefore considered as a suitable feedstock. Wood has an average calorific value of 14.4 MJ/kg (Igniss Energy, 2019). Additionally, because paper has a similar calorific value of 13.3 MJ/kg and has a lower moisture content ranging between 5-29.7%, paper fractions were also considered. It should be noted that these calorific values were not used for calculations in this study. The calorific value of the wood and paper waste was calculated in Section 4, by determining the Higher Heating Value (HHV) of the flue gas components for wood as obtained in Section 3. The term "dry combustible organic waste" (DCOW) is used for this study to refer to the wood and paper sub-categories of MSW and C&I waste.

The total amount of wood and paper MSW and C&I waste sent to landfill in the Greater Metropole Sydney and Hunter and Newcastle LGAs is shown in Table 2-4. This means that the total amount of eligible waste available for BECCS is approximately 830,000 tonnes/year, representing 5% of all waste collected in NSW in a year. Current efforts towards a circular economy may lead to competition for this available waste. However, those efforts may also increase the availability of cleaner end-life organic materials, which would facilitate BECCS.

Table 2-4: Eligible MSW and C&I waste for BECCS use (tonnes/year) (Australian Government, 2018)

Waste Stream	MSW	C&I	Total
Wood	18,549	263,684	282,233
Paper & Cardboard	270,063	277,689	547,752
Total	288,613	541,373	829,985

2.3 Task 1.3 and 1.4: Preliminary BECCS network for NSW

2.3.1 CO_2 Storage Site

A key geological CO_2 storage site which is still undergoing evaluation in NSW is the Pondie Range Trough in the Darling Basin. Additional potential storage sites on the east coast of Australia but not in

NSW include the Surat Basin, Eromanga and Galilee Basin (all in Queensland) as well as Gippsland in Victoria. For the purposes of this scoping study, the Darling Basin was used to obtain initial estimates for the BECCS transport and storage network. Previous work (CO2CRC *et al*., 2016) has shown that transport and storage costs to the Surat Basin and Gippsland are in a similar range. The characteristics of the Pondie Range Trough (based on data from the Mena Murtee-1 well) are outlined in Table 2-5.

Table 2-5: Characteristics of the selected geological storage site (Watson *et al*., 2015)

Storage basin (Horizon)	Areal extent (km^2)	Formation thickness (m)	Injection depth (m)	Porosity (%)	Permeability (mD)	Fracture gradient (MPa/km)
Darling (DST average Pondie Range)	1,300	115	1,640	12%	350	24.5

2.3.2 BECCS network

The waste sources considered are combustible MSW and C&I waste (DCOW). For the purpose of further modelling, wood and paper from both sources were chosen as a source feed, either exclusively from MSW or C&I waste or as a combination of wood and paper from both sources. The hourly flowrates available for C&I and MSW DCOW utilisation are shown in Table 2-6, with C&I sources having significantly higher availability of wood waste.

Table 2-6: Hourly waste availability for BECCS case studies (derived from data in Table 2-4)

Mass Available (kg/h)	Wood	Paper & Cardboard	Total
MSW (Wood + Paper only)	2,491	36,270	38,761
C&I (Wood + Paper only)	35,413	37,294	72,707

Based on the fuel consumption of the power plants selected and restricted by the amount of MSW-DCOW available for BECCS (38,761 kg/h) in NSW, it was estimated that a ratio of 1-5% co-combustion of MSW-DCOW with coal is possible. This is limited to co-combustion in one unit at each of the power plants, essentially creating a plant network. Alternatively, the BECCS network could have higher co-combustion ratios of up to 10%; however, this would be limited to co-combustion at only one power plant. When also considering DCOW availability from C&I sources, it was possible to achieve a 5% co-firing ratio for single units at each of the plants in the network. A 10% co-firing ratio was possible if only done at a single power plant. Therefore, the waste source for all the cases was obtained from MSW and C&I DCOW sources to allow for up to 10% co-firing.

The case studies explored in this preliminary network analysis are shown in Figure 2-9. The co-firing proportion options considered were at 0%, 5% and 10% by mass of DCOW, split equally between wood and paper at the power plants of Bayswater, Mt Piper and Eraring, with each scenario considered with and without CCS. This is in the same range as the majority of commercial scale co-firing tests, which have been undertaken at ratios around 10%, rarely exceeding 20% (Pedersen *et al.*, 1996; Wieck-Hansen, Overgaard and Larsen, 2000; Annamalai *et al.*, 2003; Cheng *et al.*, 2016; Bhuiyan *et al.*, 2018). One study (Demirbas, 2007) found only a small drop in efficiency of 1.3% when firing 10% MSW. When the fraction of DCOW is closer to 100%, as in a wholly waste to energy dedicated plant, net thermal efficiency is 10-20% lower than regular coal-fired power plants (Vekemans and Chaouki, 2016).

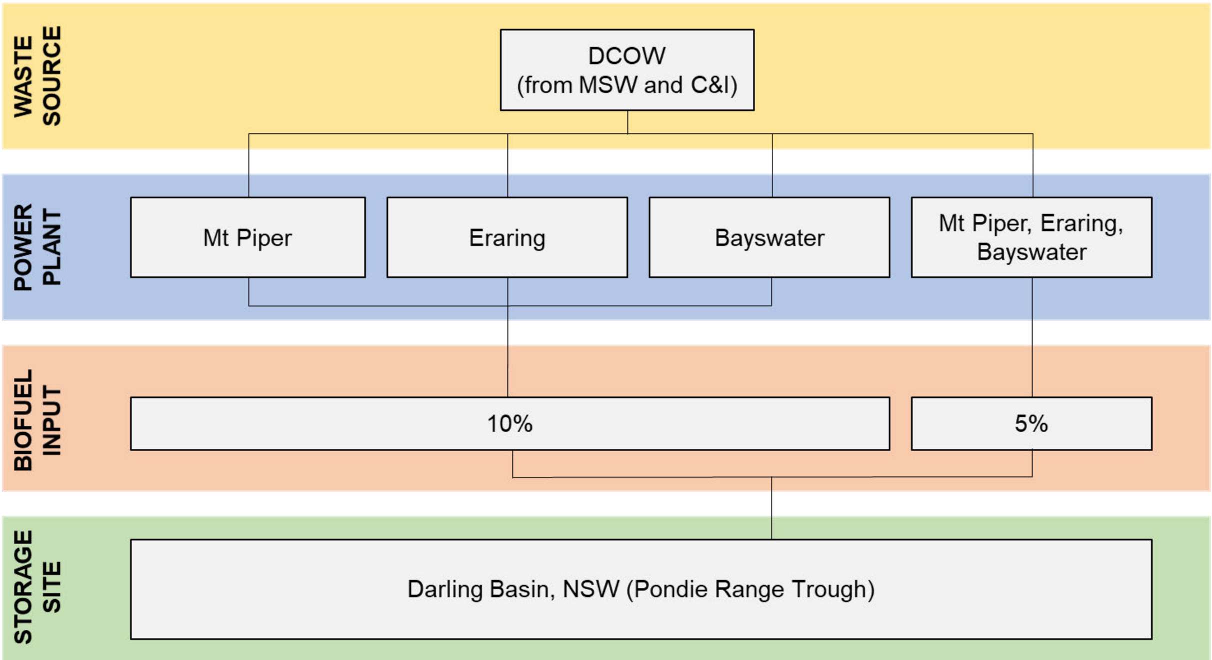

Figure 2-9: Case studies for preliminary BECCS network

Case Study 1: BECCS Network – all plants.

For a BECCS network utilising the capacity of all plants, a co-firing ratio of 5% at each plant was used. Figure 2-10 shows the total distance for the pipeline network is 1,173 km; comprising of pipelines connecting Eraring and Bayswater to a booster point at Dunedoo which connects with the pipeline from Mt Piper. The trunkline from Dunedoo to the storage point at Mena Murtee-1 is 645 km. All distances were estimated by taking the shortest distance by road between the points considered.

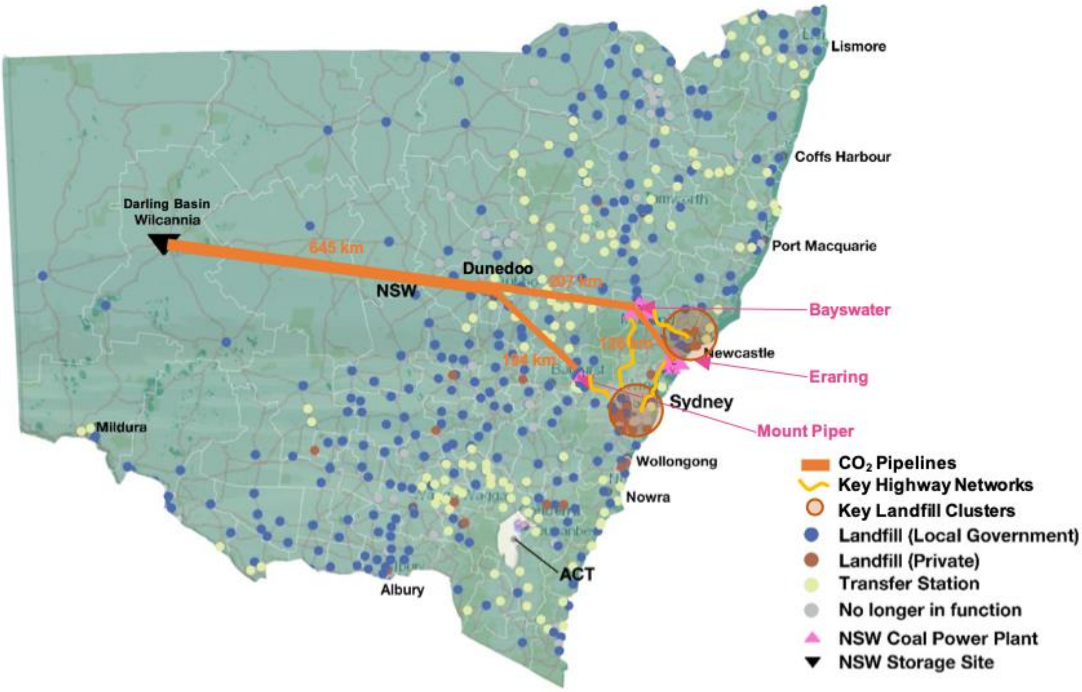

Figure 2-10: Preliminary BECCS network with all plants (Bayswater, Eraring and Mt Piper)

Case studies 2-4: Single power plant utilisation

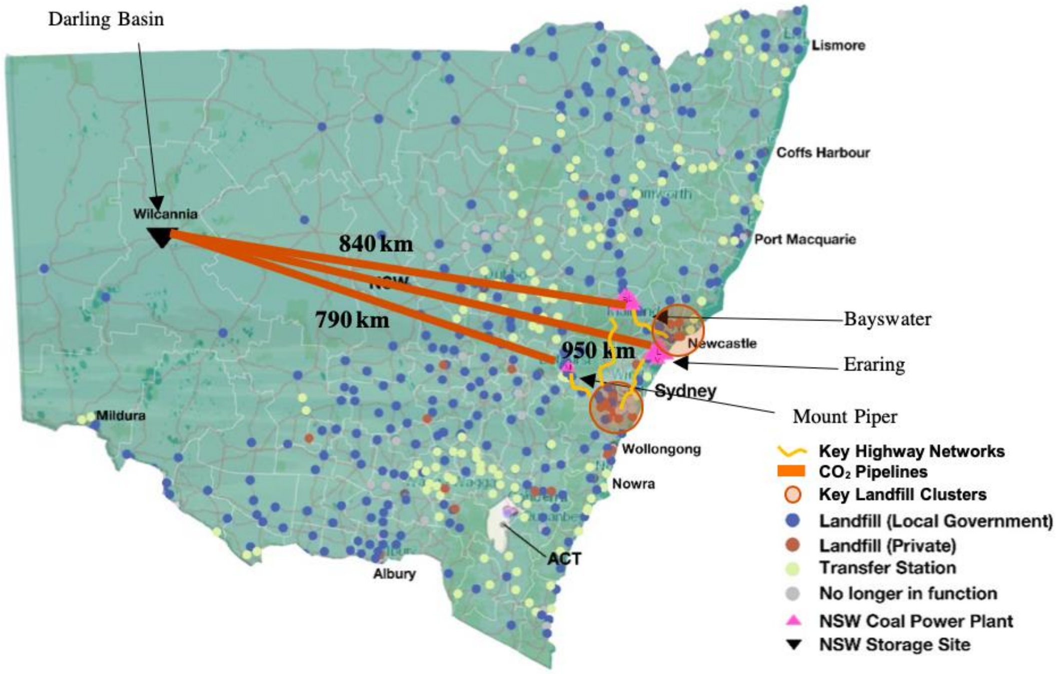

Figure 2-11: Preliminary BECCS networks for single plant utilisation (Bayswater, Eraring or Mt Piper)

For these cases, a maximum 10% co-firing ratio was used. Figure 2-11 shows the possible networks for 10% bio-mass utilisation in a single plant to Darling Basin. The shortest pipeline distance based on road distances is from Mt Piper at 790 km, followed by Bayswater at 840 km and Eraring at 950 km.

2.4 Task 1.5: Policy and regulatory barriers and opportunities for BECCS using MSW

2.4.1 Carbon capture and storage policy

Australia has been ranked first globally for its development and implementation of CCS legislative frameworks (Havercroft, 2018).The legislative frameworks operate on three levels: Commonwealth offshore, State offshore and State onshore CCS operations (Vuksic, 2017). Some of the issues addressed by the legislation include long term issues surrounding liability regarding ownership of CCS storage sites during and after completion of sequestration, liability for damages in regard to health, safety and environmental aspects of CCS, and the enforcement mechanisms in approving projects, and serious safety risks including leaks and migration of CCS storage (Havercroft, Macrory and Stewart, 2018).

There are also international guidance documents and emerging standards for the design, operation and regulation of CCS projects covering vast aspects. The technical committee for carbon dioxide capture, transportation and geological storage (ISO/TC 265) established by the International Organization of Standardization in 2011 aims to standardize global practice regarding CCS project design and operation at all stages (International Organization for Standardization, 2019). Australia is currently a practicing member on the committee which has published 4 standards and technical reports each about regulation of CCS, with 4 standards under development. The relevant published standards and technical reports are listed in Table 2-7 (International Organization for Standardization, 2019).

Table 2-7: International standards (ISO) relating to CCS regulation (International Organization for Standardization, 2019)

Standard number	Standard name	Description
ISO/TR 27912 (2016)	Carbon dioxide capture systems, technologies and processes	Technical report which outlines principles of CO_2 capture system necessary for developing CCS standards
ISO 13623 (2017)	Petroleum and natural gas industries – Pipeline transportation systems	Specifies requirements for design, materials, construction, operation and abandonment of natural gas and petroleum industry pipelines
ISO 27913 (2016)	Pipeline transportation systems	Outlines specific requirements for CO_2 pipelines for the purpose of geological storage not outlined in ISO 13623 (2017)
ISO 27914 (2017)	Geological storage	Outlines requirements for geological storage of CO_2 in a safe, long term manner for both onshore and offshore sites. Includes site selection, design, operation and closure guidelines.
ISO/TR 27915 (2017)	Quantification and verification	Technical report reviewing literature on good practice in quantifying GHG emissions and reduction in the CCS chain including Life Cycle Assessment of CCS projects.
ISO 27916 (2019)	Carbon dioxide storage using enhanced oil recovery (CO_2-EOR)	Outlines calculation method for determining safe CO_2 storage levels in enhanced recovery operations of oil and other hydrocarbons
ISO 27917 (2017)	Vocabulary – Cross cutting terms	Defines common terminology used in CCS projects including definitions of CO_2, terms relating to risk, relationships with stakeholders etc.
ISO/TR 27918 (2018)	Lifecycle risk management for integrated CCS projects	Technical report for future development of standards relating to risk management of CCS projects in the future in relation to health and safety
ISO 27919-1 (2018)	Part 1: Performance evaluation method for post-combustion CO_2 capture (PCC) integrated with a power plant	Specifies methods, instruments and data needed for measuring, evaluating and reporting performance of PCC

Carbon storage

Some states and territories have introduced legislation for the regulation of onshore greenhouse gas storage, including NSW, Victoria, Queensland and Western Australia with the NSW legislation yet to pass. For the purposes of this scoping study for NSW power plants for which a future CCS (and hence BECCS) network might include storage in NSW, Queensland or Victoria, only the Commonwealth and eastern state legislative regimes were reviewed in more detail.

The Commonwealth and the State of Victoria have developed legislative regimes for offshore storage (Vuksic, 2017):

- Commonwealth regime – Offshore petroleum and greenhouse gas storage Act 2006 (Cth)
- Victorian regime – Offshore petroleum and greenhouse gas storage Act 2010 (Vic)

The two offshore statutory schemes operate similarly on most stages of CCS activity as shown in Table 2-8, however a noticeable difference regarding long term liability is observed. In the Commonwealth regime, the Commonwealth indemnifies any damages incurred by the CCS operator post closure. In the State regime, while the state claims ownership of all injected gases, it does not assume the CCS operator's common law liability (Vuksic, 2017).

There is no comprehensive Commonwealth statutory regime for onshore CCS storage. As such, there are state based legislations (Zahar, Peel and Godden, 2012):

- Victorian regime – Greenhouse gas geological sequestration Act 2008 (VIC)
- Queensland regime – Greenhouse gas storage Act 2009 (QLD)

Table 2-8: Offshore CCS gas storage legislative schemes (Zahar, Peel and Godden, 2012; Vuksic, 2017)

Stage of CCS activity	Commonwealth regime – Offshore petroleum and greenhouse gas storage Act 2006 (Cth) (Parliament of Australia, 2018)	Victorian regime – Offshore petroleum and greenhouse gas storage Act 2010 (Vic) (Parliament of Victoria, 2010)
Exploration	Must hold GHG assessment permit for exploration of a potential offshore storage site (s 289)	Must hold GHG assessment permit for exploration of a potential offshore storage site (s 284)
Site declaration	The licensee may apply for the declaration of a site as an identified greenhouse gas storage formation by applying to the responsible Commonwealth Minister (s 312)	The licensee may apply for the declaration of a site as an identified greenhouse gas storage formation by applying to the responsible Minister (s 315)
Injection and operation	The licensee must apply for a GHG injection license over the storage formation (s 361); injection must commence within 5 years or the license is cancelled (s 360)	The licensee must apply for a GHG injection license over the storage formation (s 372); injection must commence within 5 years or the license is cancelled (s 378)
Site closure	When injection operations have been completed, the licensee must apply for a site closing certificate (Part I, Div 7) The application includes modelling and assessment of injected GHG; migration pathways and their consequences; suggestions on monitoring (s 386) A pre-certificate stipulates the total cost of monitoring and assessments by the Cth (s388) which must be paid (s 391) before a site closure certificate is issued (s 392).	When injection operations have been completed, the licensee must apply for a site closing certificate (Part 3.4, Div 7) The application includes modelling and assessment of injected GHG; migration pathways and their consequences; suggestions on monitoring (s 414) A pre-certificate stipulates the total cost of monitoring and assessments by the Cth (s 420) which must be paid as security (s 426) before a site closure certificate is issued (s 427)
Site closure assurance period	A closure assurance period (CAP) of a minimum of 15 years is required for the Cth to declare closure where they have been satisfied there are no significant risks or changes in storage conditions (s 399)	No equivalent CAP, but licensee must pay State expenses in carrying out pre-certificate activities (s 433)
Post-closure	After the CAP, the Cth must indemnify the license holder against any post closure damages incurred (s 401)	The crown becomes the owner of any injected GHG after Site Closure Certificate issuance (s 67) but does not assume CCS operator's common law liability (Peter Batchelor Minister for Energy and Resources, 2010) .

The state regimes cover similar stages of CCS activities, although varying in specifics. All frameworks confer land ownership to the state (Havercroft, Macrory and Stewart, 2018) and injected substance ownership once injection licenses are surrendered. Neither legislative schemes explicitly state whether the State assumes the CCS leaseholder's long-term common-law liability. While NSW introduced a legislative framework to the legislative assembly it has yet to be passed (Parliament of New South Wales, 2010). Therefore, reference frameworks for onshore storage are the Victoria and Queensland Frameworks shown in Table 2-9.

Table 2-9: Onshore CCS carbon storage legislative frameworks (Zahar, Peel and Godden, 2012).

Stage of CCS activity	Victorian regime -- Greenhouse gas geological sequestration Act 2008 (VIC) (Parliament of Victoria, 2008)	Queensland regime -- Greenhouse gas storage Act 2009 (QLD) (Parliament of Queensland, 2009)
Exploration	Must obtain a greenhouse gas exploration permit for potential storage sites (Part 3) Applicant must inform minister of suitable storage sites identified (s 56)	Must obtain a greenhouse gas exploration permit for potential storage sites (Part 2, Div 2) Applicant may inform minister of suitable storage sites identified (s 101)
Injection	The licensee must apply for a greenhouse gas injection and monitoring license (s 72) by providing details of the area and activities (s 73)	The licensee must apply for a greenhouse gas injection and storage lease by providing a development plan detailing activities (s 139)
Closure	When injection operations have been completed, the licensee must apply for a surrender application (s 168). The application includes modelling and assessment of injected GHG; migration pathways and their consequences (s 171) and risk mitigation measures (s 170) A pre-certificate stipulates the total cost long-term of monitoring and verifications by the state which must be paid (s 174) before a site closure certificate is issued.	When injection operations have been completed, the licensee must apply for a surrender application (s 176). The application includes modelling and assessment of injected GHG; migration pathways and their consequences (s 177) and risk mitigation measures (s 178) A pre-certificate stipulates the total cost long-term of monitoring and verifications by the state which must be paid (s 174) before a site closure certificate is issued.
Post closure	On lease surrender, injected GHG are State property with the State having responsibility for monitoring of the site (s 16). But the State does not explicitly assume CCS operator's common law liability.	On lease surrender, injected GHG are State property with the State having responsibility for monitoring of the site (s 181). But the State does not explicitly assume CCS operator's common law liability.

It should also be noted that there are international guidelines on storage as prescribed by the International Organisation of Standardisation. The relevant standard is (International Organization of Standardization, 2019b):

- International standard (adopted in Australia) – AS/ISO 27914:2019 Carbon dioxide capture and geological storage – geological storage (Standards Australia, 2019)

This standard has recently been adopted by Australia and provides guidelines on site selection, screening, characterisation, design, operation and closure (Standards Australia, 2019). Additional aspects covered also include risk management strategy development, stakeholder and community engagement and communication. This standard does not apply to, modify, interpret or supersede the national regulations in Australia, and therefore provides no guidelines post-closure (Standards Australia, 2019). In addition, it also does not apply to or modify property rights or interests in the surface or subsurface (Standards Australia, 2019). However, it could help inform future policy and CCS legislation in NSW.

CCS transport regulation

Regulation surrounding CCS Transport is primarily focused on the design and operation of CO_2 pipelines. The regulations and standards regulating pipeline design, construction and operation have been defined at the international and domestic scales (Terenzi, 2018). The relevant domestic framework for CO_2 pipelines is prescribed by standards drafted by the Australian Pipelines and Gas Association:

- Australian standard – AS 2885: Pipelines – Gas and petroleum (2018)

There are several parts to the standard which cover design, welding, operation and maintenance and field pressure testing of steel pipelines that are used to transfer single phase and multiphase hydrocarbon fluids (Ministerial Council on Mineral and Petroleum Resources, 2005). Although CO_2 is not defined in the standard, the standard allows for inclusion of pipelines transporting a range of substances.

Additionally, the process for obtaining transport pipeline licenses is covered under both Commonwealth and State statutes (Carbon Storage Taskforce, 2009):

- Commonwealth (Offshore) – Offshore petroleum and greenhouse gas storage Act 2006 (Cth)
- Queensland (Onshore) – Petroleum and gas (Production and Safety) Act 2004 (QLD)
- Victoria (Onshore) – Victorian pipelines Act 2005 (VIC)
- NSW (Onshore) – Petroleum (Onshore) Act 1991 (NSW)
- NSW (Offshore) – Petroleum (Offshore) Act 1982 (NSW)

Table 2-10: Offshore pipeline legislation

	Commonwealth regime -- Offshore petroleum and greenhouse gas storage Act 2006 (Cth) (Parliament of Australia, 2017)	NSW regime -- Petroleum (Offshore) Act 1982 (NSW) (New South Wales Government, 2014)
Application for licence	A greenhouse gas substance must be approved by joint authority subject to its suitability for injection and storage (s 213)	Details of design, construction, size, proposals of work, technical and financial advice must be shown in application (s 65)
	Details of design, construction, size, proposals of work, technical and financial advice must be shown in application (s 217)	Plan of pipeline must include route, sites of pumping stations and terminal points (s 65)
	Plan of pipeline must include route, sites of pumping stations and terminal points (s 218)	
Rights conferred by pipeline licence	Offshore pipeline construction, operation of pipeline and pumping stations and carry out incidental acts to the pipeline (s 211)	Offshore pipeline construction, operation of pipeline and pumping stations and carry out incidental acts to the pipeline (s 67)
Alteration or removal of pipeline	The responsible minister has the right to order alterations to, move the location of or remove a pipeline (s 216)	The responsible minister has the right to order alterations in design, construction, rout or position of pipeline (s 73)

The offshore regimes for both the Commonwealth and NSW contain a similar regime to each other and cover aspects of application and rights conferred to the licence holder as shown in Table 2-10.

There is no Commonwealth regime for onshore pipelines, with State regimes covering issues including application process, rights conferred by the licence and liability. The NSW regime does not contain such particulars, but under a production lease allows for the construction of pipelines (New South Wales Government, 2018). Victoria has a separate legislative instrument for the regulation of pipelines which has requirements covering not only licence application and subsequent rights, but requirements in relation to land, construction of the pipeline itself, management plans and rehabilitation and compensation in relation to the pipeline. The particulars of the Victorian and Queensland regime are shown in Table 2-11.

Table 2-11: State legislation for onshore pipelines

	Victoria Regime – Victorian pipelines Act 2005 (VIC) (Parliament of Victoria, 2005)	Queensland Regime -- Petroleum and gas (Production and safety) Act 2004 (QLD) (Queensland Government, 2009)
Application for licence	A consultation plan containing information about the types of activities, impacts of construction and operation on land, health, safety and environment and statement advising owners of land of the proposal (s 17). Applicant can apply for pipeline license after consultation plan has been approved (s 28). The application will contain proposed use of the pipeline and a map of the pipeline corridor (s 30)	Must apply for a point-to-point pipeline licence and area pipeline licence separately (s 407) Details of land description, type and purpose of pipeline, terminal points, day of completion of construction, extent and nature of activities proposed under the licence (s 408)
Rights conferred by pipeline licence	Construction and operation of pipeline in accordance with the pipeline licence (s 58)	Construction and operation of pipeline (s 401), transportation of GHGs (s 402) and carrying out acts incidental to pipeline (s 403)
Obligations in operating pipeline	Conditions of the licence may include conditions relating to safety, cultural heritage protection, environmental protection (s 54)	Licence holder must operate in a way that ensures continuing capacity to safely and reliably transport the pipeline substance (s 422)
Rights of the Minister	The minister may amend the conditions of the pipeline license without request (s 62)	The responsible minister may amend a licence to reduce the pipeline land area (s 425) and ask for any further amendments (s 434)
Liability	The licensee must hold insurance in relation to liability as a result of carrying out pipeline operation or any actions under license including the escape of substances from the pipeline (s 144)	Pipeline licence holder will have liability for damages incurred as a result of the conditions of the licence and is not civilly liable for damages if the failure or fuel gas being not of the prescribed quality was beyond the licence holder's control (s 437)

While international treaties and regulations exist on CO_2 transport on both a transboundary and offshore level, due to the nature of the sites identified as onshore (Pondie Range Trough), the main international regulations of relevance are those related to pipeline design, including (International Organization of Standardization, 2019a):

- International standard – ISO 13623: Petroleum and natural gas industries – pipeline transportation systems (2017)
- International standard – ISO 27913: Carbon dioxide capture, transportation and geological storage – pipeline transportation systems (2016)

2.4.2 Municipal solid waste policy

Key federal and NSW policies and legislation related to waste disposal and MSW management in the energy sector are shown in Table 2-12. These policies reveal that BECCS may be classified as an 'Alternative Waste Treatment', hence making it eligible to receive Australian Carbon Credit Units under the *Carbon Credits (Carbon Farming Initiative) Act 2011 (Cth)* (Department of the Environment and Energy, 2015).

Table 2-12: Key federal and NSW policies relating to MSW management in the energy sector

Policy	Policy Description & Relevance to MSW/Bio-Energy	Reference
'National Waste Policy: Less waste, more resources (Cth)'	• Framework for collective action by businesses, governments, communities and individuals regarding waste management in a circular economy • One aim is increasing industry capacity by identifying opportunities across municipal solid waste, commercial and industrial waste and construction and demolition waste streams for energy recovery.	(Department of the Environment and Energy, 2018a)
'National Environment Protection Measures (Cth)'	• National Objectives designed to assist in protection or managing particular aspects of the environment • Provides method for monitoring environmental impacts associated with hazardous waste and re-use and recycling of used materials	(National Environment Protection Council, 2018)
'Product Stewardship Act 2011 (Cth)'	• Framework to manage environmental, health and safety impacts of product and their disposal	(Australian Government, 2011)
'National Greenhouse and Energy Reporting Act 2007 (Cth)'	• Single national framework for reporting information about greenhouse gas emissions, energy production and energy consumption	(Clean Energy Regulator, 2007)
'Carbon Credits (Carbon Farming Initiative) Act 2011 (Cth)'	• Defines alternative waste treatment (AWT) as a range of activities that process mixed solid waste that would have gone to landfill into products such as compost, fuel or biogas, and increase recovery of resources including plastics, glass and metals • All eligible projects will be able to receive Australian Carbon Credit Units for emission reductions for the processing of eligible waste for a seven-year crediting period.	(Department of the Environment and Energy, 2015)
'Protection of the Environment Operations Act 1997 (NSW)'	• Enables government to set out protection of the environment policies (PEPs) for reducing pollution. • Object of Act is to reduce risks to human health by mechanisms that promote elimination of harmful wastes, recovery of material and reduction of material at its source	(NSW Environmental Protection Authority, 2018c)
'Protection of the Environment Operations (Waste) Regulation 2014 (NSW)'	• States contributions to be paid by scheduled waste facilities for waste received as well as exemptions, rebates, reporting requirements.	(NSW Environmental Protection Authority, 2018b)
'Waste Avoidance and Resource Recovery Act 2001 (NSW)'	• Sets out schemes and fees to be paid out for beverage containers and empowers the EPA to develop waste strategies for the state	(NSW Environmental Protection Authority, 2018d)
'Waste Classification Guidelines (NSW)'	As defined by the EPA to comply with the waste legislation, waste can be classified into one of the six classes for appropriate management and disposal under a 'risk-based system' • special waste • liquid waste • hazardous waste • restricted solid waste • general solid waste (putrescible) • general solid waste (non-putrescible)	(NSW Environmental Protection Authority, 2014)

3 Task 2: Modelling of fuel-flexible power generation

This Section outlines the results of the simulation of different ratios of Dry Combustible Organic Waste (DCOW) to coal in combustion. The aim of this simulation was to evaluate the impact of varying fuel inorganic composition on the released flue gas and, in particular, on the inorganic concentration.

This Section elaborates on the development details of the model including assumptions relating to the

1. Solid Fuel
2. Combustion Model
3. Trace Element Model

3.1 Model development

3.1.1 Solid fuel

The solid fuels modelled are coal co-fired with DCOW. The coal is representative of that used at the Mt Piper power plant whilst the DCOW is assumed to be recycled/waste wood. The combustion model is based on the same configurations as those at the 250-kW PACT facility down-fired burner located at Beighton in the UK (Clements *et al.*, 2015).

Because the precise composition of the coal used in NSW power plants was not available, the following assumptions were used. The ratio of volatile matter to fixed carbon is fixed at 0.62 (Donahue and Rais, 2009). Despite this estimation, the possible ratio may be within a wide range of values depending on coal age and origin. The initial ash-forming elements and trace element concentrations in coal are those reported for Gunnedah basin coal (Ward *et al.*, 1999). The proximate analysis, ultimate analysis, initial ash-forming element concentrations, and trace elements of waste wood are those provided by the PACT facility.

3.1.2 Combustion model

The model compares co-combustion of waste wood mass at 5% or 10%. In order to simplify the co-combustion, each solid fuel enters separately and produces its own flue gas stream. Both flue gas streams are merged at the outlet. The model is trial-run to adjust the inlet air flow rate in order to obtain roughly 3 to 4% of O_2 dry molar percentage at the outlet of each column. The detailed combustion flow diagram is shown in Figure 3-1.

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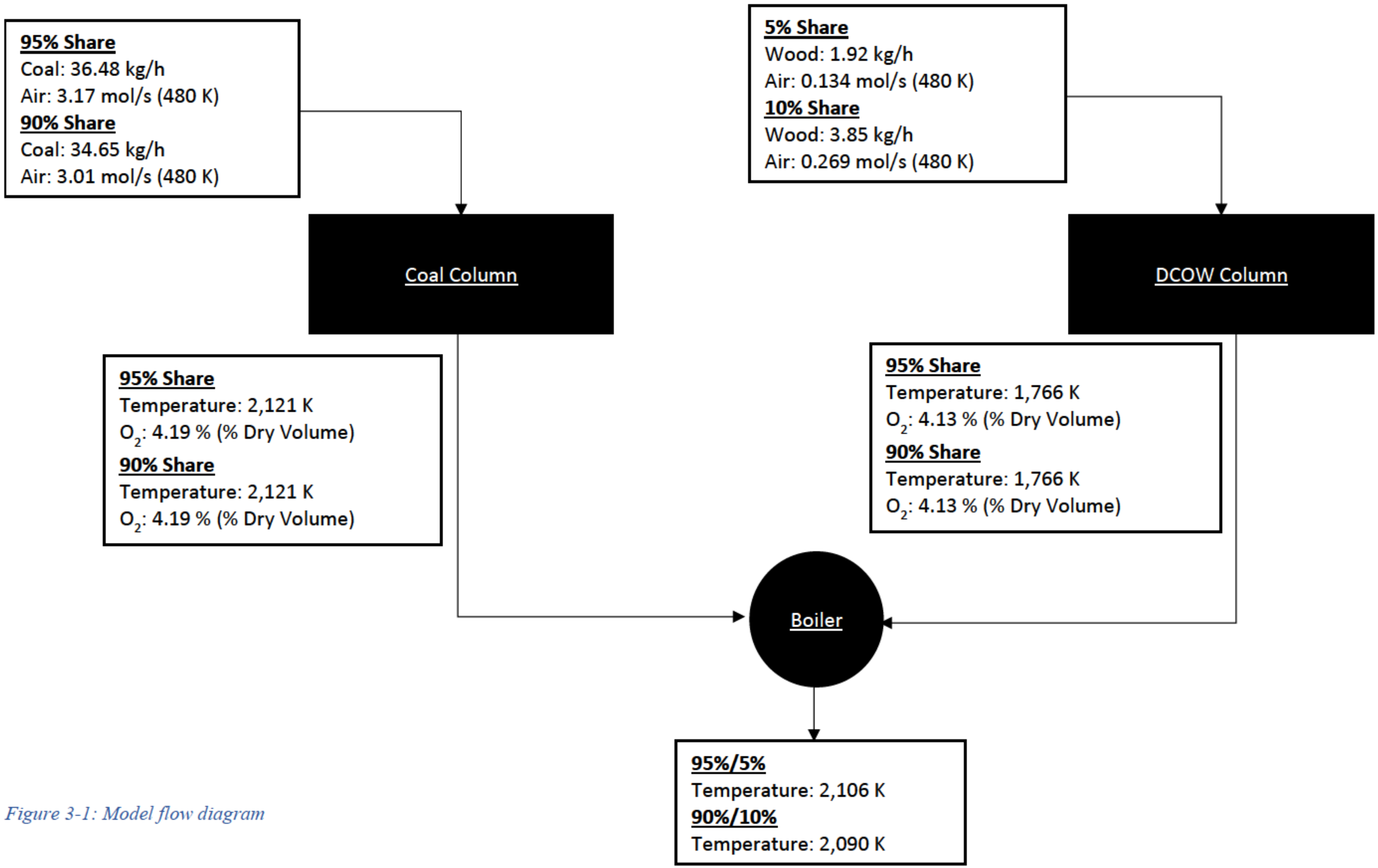

Figure 3-1: Model flow diagram

The model is designed based on a plug-flow reactor as shown in Figure 3-2. Each column is discretised axially into small circular disks. Within each disk, combustible gases are released from solid fuels as products of heterogeneous reactions and pyrolysis. The gases exothermically react with O_2 in the bulk. The bulk temperature in the element becomes the next disk inlet temperature.

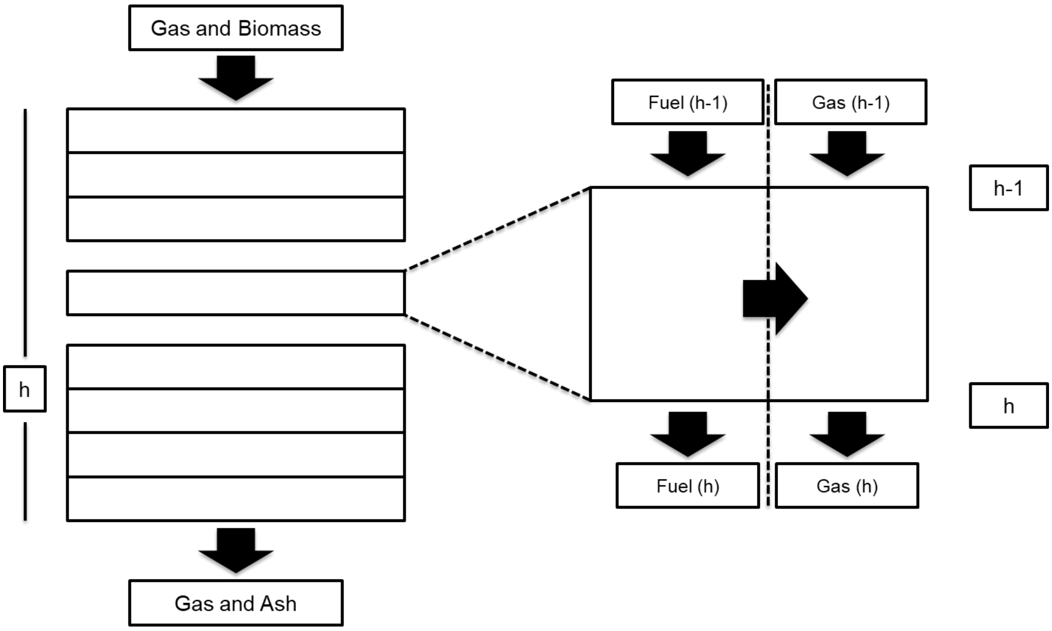

Figure 3-2: Modelling methodology

Coal pyrolysis kinetic equations used in the model are estimated based on Ward *et al.* (1999). Coal char heterogeneous reaction kinetic equations as a function of bulk gas pressure are based on Roberts and Harris (2000). Despite containing relatively significant amounts of inorganics, waste wood kinetic equations are assumed to be similar to those of virgin wood. Waste wood pyrolysis kinetic equations are based on Blasi and Branca (2001), whilst the kinetic equations of its char heterogeneous reactions with O_2, H_2O, and CO_2 are based on van den Aarsen, Beenackers and van Swaaij (1985) and Kojima, Assavadakorn and Furusawa (1993), respectively.

3.1.3 Trace element model

The solid residues after combustion, typically referred to as "ash", are mostly composed of oxides and salts of a handful of elements (generally over 95 wt%). The most significant of these ash-forming elements are (Werkelin *et al.*, 2010) silicon (Si, mostly as silica), phosphorus (P, mostly as phosphate), sulphur (S, mostly as sulphates in salts), chlorine (Cl, as chloride in salts), and positive metal ions of aluminium (Al), iron (Fe), calcium (Ca), magnesium (Mg), manganese (Mn), sodium (Na), and potassium (K). Other elements in biomass combustion residues are only present in trace amounts, as they are more unique elements required for biological processes and specific organic molecules, like chlorophyll.

The ash-forming element and trace element concentration throughout the columns is calculated with the same modelling methodology shown in Figure 3-2. However, unlike the combustible elements, e.g. C, H, and O, their occurrences within each disk are estimated at chemical equilibrium. The motivation of using chemical equilibrium is the unavailability of the trace and ash-forming element combustion kinetic data and to avoid extremely complex computations even if the kinetic data were available.

Chemapp is used as the chemical equilibrium calculation tool integrated within the simulation environment. The advantages of using Chemapp is to enhance the calculation for large numbers of datapoints and to provide a simplified integration of a chemical equilibrium platform with the model (Eriksson and Königsberger, 2008).

At the outlet, both streams are merged. The combined stream has a new temperature and molar masses. One final chemical equilibrium calculation is applied to obtain combined ash-forming elements and trace element concentrations.

3.2 Impact on exhaust gas with DCOW co-combustion

The results as shown in Figure 3-3 present pure coal combustions as well as co-combustion combinations of 5% and 10% DCOW. The combined flue gas pressure for both cases is set at 1 atm. Due to the inlet gas flow rate adjustment, temperature and gas compositions leaving both columns have relatively similar molar percentage, as shown in Table 3-1.

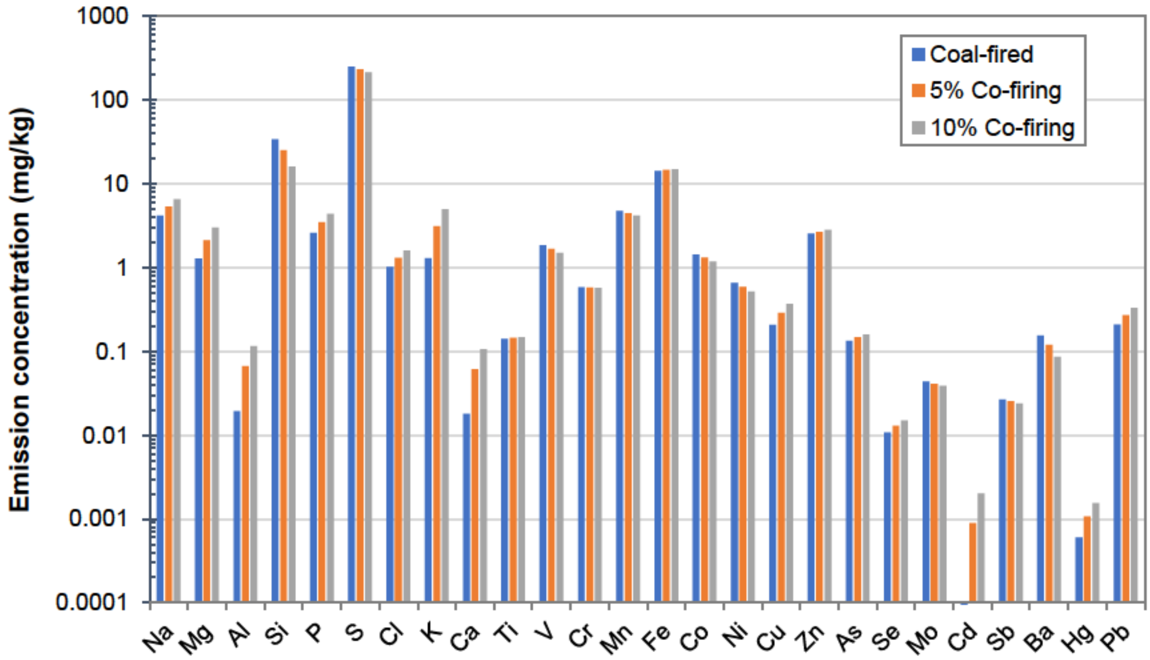

Figure 3-3: Combined elemental concentration for pure coal, 5% and 10% DCOW co-combustion.

Table 3-1: Flue gas compositions leaving combustion columns for each fuel

Fuel	CO_2	H_2O	O_2	N_2
Coal	14.0 %	6.7 %	3.9 %	75.4 %
DCOW	14.5 %	11.2 %	3.7 %	70.7 %

The combined concentrations of the trace elements profile for the co-fired flue gas are shown in Figure 3-3. For a lower share of coal (that is higher MSW rates), more ash-forming elements are released, except for silica, due to the contribution of the waste wood. Silica has a different behaviour because it is not a major element in waste wood and coal share reduction decreases silica emission significantly. The concentration of trace elements decreases as co-firing rate increases. On the other hand, some elements such as Pb, Cd, and As, show the opposite trend, as these are typically not present in biomass. This indicates that the emission concentrations depend on the initial concentrations, e.g. waste wood has more Cd than coal, so a higher waste wood share clearly contributes to more released Cd.

The results show that parallel entrained-flow combustion is capable of predicting the emitted trace element concentrations. However, the evaluation comprehensiveness of this model is limited with respect to trace element interaction within the particle. Entrained flow combustion often operates at very high temperatures (above 1,250 °C) and has very small particle size with average of 45 µm (van Krevelen, 1993). At such extreme conditions, volatile elements tend to devolatilise rapidly due to the low Biot number (i.e. the ratio of internal to surface heat transfer for the aerosol particle) and undergo chemical reaction and phase change in the bulk phase. Future analysis on less extreme conditions, e.g. a fluidised-bed boiler, may be required to observe elemental interactions in the bed. Coal introduction to the bed may, to some extent, prevent potassium release because of large amounts of aluminosilicate reacting with potassium chloride to form potassium aluminosilicate and thereby prevent corrosion and slagging (Coda *et al.*, 2001). Trace elements might undergo similar interactions that have potential to block their devolatilisation.

The combined emission concentrations are compared with a regulated emission standard as an assessment of whether the solid fuels are safe to burn. The emission limits applying to power stations in NSW are regulated by the *Protection of the Environment Operations (POEO) Act 1997 (NSW)* (New South Wales Government, 2019b) and *Protection of the Environment Operations (Clean Air) Regulation 2010 (NSW)* (New South Wales Government, 2019a). The Act sets out regulation limits for plants depending primarily on their age (NSW Environmental Protection Authority, 2018a).

*Table 3-2: Combined model evaluation based on NSW POEO regulations for **Type 1** and **Type 2** emissions*

Elements	Individual Limit	Type 1+2 Limit	Coal	Type 1+2	5% Co-fired (mg m^{-3})	Type 1+2	10% Co-firing (mg m^{-3})	Type 1+2
Cd	0.2	Total: 1	Negligible	9.76	0.0009	9.29	0.0020	8.81
Hg	0.2		0.0006		0.0011		0.0016	
Sb	N/A		0.0266		0.0252		0.0238	
As			0.1331		0.1459		0.1590	
Pb			0.2080		0.2677		0.3285	
Cr			0.5800		0.5755		0.5710	
Co			1.4224		1.3023		1.1799	
Mn			4.6911		4.4342		4.1726	
Ni			0.6542		0.5852		0.5149	
V			1.8392		1.6630		1.4836	
Cu			0.2066		0.2876		0.3700	

The addition of a co-firing unit to the NSW power plants categorises them as Group 6 activities under the Act, as this addition leads to a change in the nature of impurities emitted under Section 33(1) of the *Protection of the Environment Operations (Clean Air) Regulation 2010 (NSW)* (New South Wales Government, 2019a). The upper emission limits are shown in Table 3-2 along with the assessed modelling concentrations. The emissions are classified into Type 1 and Type 2 emissions which, given the category of power plant (Group 6), have a combined (Type 1+2) emission limit. Type 1 substances consist of antimony (Sb), arsenic (As), cadmium (Cd), lead (Pb) or mercury (Hg). Type 2 substances consist of beryllium (Be), chromium (Cr), cobalt (Co), manganese (Mn), nickel (Ni), selenium (Se), tin (Sn) or vanadium (V). Cd and Hg emissions also have individual limits at 0.2 mg/m^3 (New South Wales Government, 2019a). From Table 3-2, it can be seen that individual Cd and Hg concentrations are below limits. On the other hand, Be, Se and Sn trace concentrations were not modelled due to lack of data. Nonetheless, the aggregated concentrations of the modelled Type 1 and 2 emissions are significantly higher than the NSW limit, with Mn and V emissions being the largest contributors. This indicates that an aerosol precipitator is required to capture aerosols formed prior to entering the emission stack. As precipitators already exist on NSW coal-fired power plants and these remove approximately 99% of aerosols (as mentioned in Section 4), the data presented here suggests that no further treatment of the emissions would be necessary to meet the applicable NSW POEO regulations, as the final emissions should be within the limits.

4 Task 3: Evaluation of the emissions reduction potential

4.1 Task 3.1 and 3.2: Emissions reduction and Landfill reduction

This Section outlines the methodology and results for the analysis of emissions and landfill use reduction due to DCOW co-firing and implementation of CCS in NSW. The results presented in this Section only refer to operating emissions and do not represent life cycle emissions, as those are reported in Section 4.2.

4.1.1 Introduction

In order to assess the carbon dioxide reduction potential for BECCS deployment with DCOW, various options of DCOW co-firing with and without capture were assessed against baseline standalone NSW black coal power plants (with and without capture). These power plant configuration options are shown in Figure 4-1.

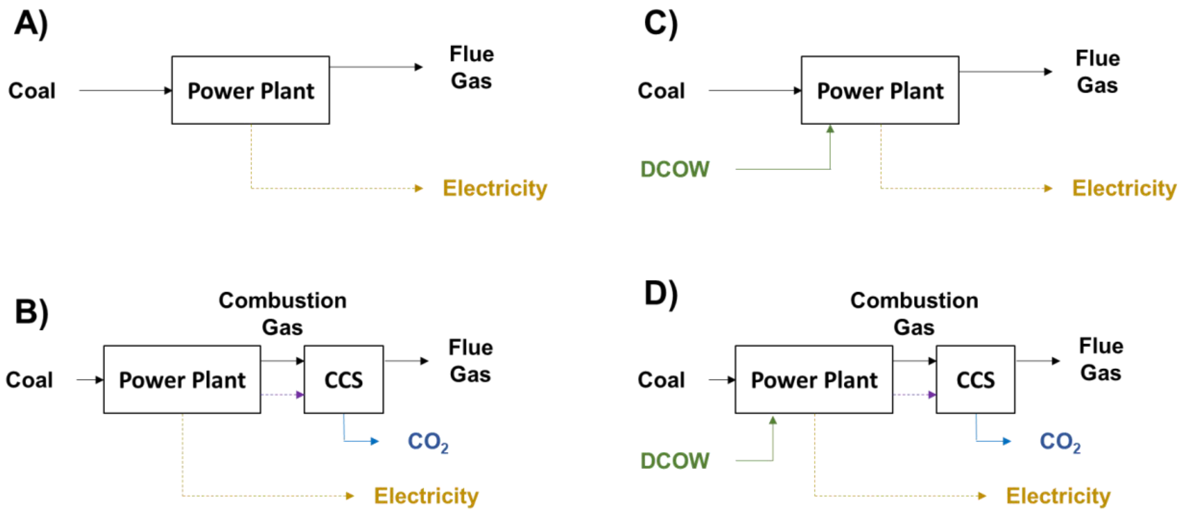

Figure 4-1: Diagram of the different power plant configurations considered for emissions reduction: A) Coal-fired (no co-firing), B) Coal-fired+CCS, C) Co-firing, and D) Co firing+CCS (BECCS co-firing)

The key process performance indicators include carbon dioxide captured, energy penalty and carbon intensity of electricity generated (kg_{CO2}/MWh_e). Performance indicators relating to CCS were obtained as model outputs from the Integrated Carbon Capture and Storage Economics Model (ICCSEM) developed by UNSW Australia (The University of New South Wales) and University of Sydney researchers, for the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). Model assumptions, operations and inputs (including those obtained from Imperial College's combustion model outlined in Section 3) are discussed further in subsequent Sections.

4.1.2 Emissions Output

Methodology

Base coal power plant operating conditions: This study considers the Mt Piper, Eraring and Bayswater power plants, as reported in Section 2.2. In addition, a base power plant is defined, representing an average NSW sub-critical pulverised fuel coal power plant, operating at 500 MW electricity output. Table 4-1 shows the technical assumptions, with the same thermal efficiency and emissions intensity assumed for all plants, based on the average of all the coal power plants in NSW. The specific plants diverge on their net electrical output, which represent the actual outputs for each plant as shown in Table 2-1.

Table 4-1: Assumptions for base coal-fired power plants

Parameter	Units	Value
Efficiency (HHV)	%	36
Emissions Intensity	t CO_2/MWh	0.874
Coal Calorific Value	MJ/kg	23.80
Fuel Consumption	kg/h	21,084
Net Electricity Output	MW_e	500
CO_2 Flue Gas Flowrate	mol/kg fuel combusted	47.24
H_2O Flue Gas Flowrate		22.72
O_2 Flue Gas Flowrate		13.22
N_2 Flue Gas Flowrate		255.16

Base parallel DCOW (wood) boiler conditions: It is assumed that a separate parallel sub-critical pulverised fuel boiler with the same boiler efficiency as the coal boiler is utilised to burn equal proportions of mixed wood and paper waste. As the difference in calorific value for wood and paper is reported to be less than 7% (Igniss Energy, 2019) and this is within the range of variability of literature data, it is assumed that the thermal properties of wood and paper are the same for the purposes of this scoping study. Variations in the calorific value assumed for the biomass would have slight effects on both the emission intensity and energy penalty for CCS, but this effect is lessened due to the low levels of co-firing. Fuel consumption, outlet flue gas flowrates and boiler temperatures as shown in Table 4-2 were all obtained from the combustion model data from Imperial College outlined in Section 3.

Table 4-2: Combustion model outputs for DCOW (Wood) emissions calculations

Parameter	Units	Value
Boiler Outlet Temperature	K	1765
Fuel Consumption	kg/h	5.78
CO_2 Flue Gas Flowrate	mol/kg fuel combusted	40.79
H_2O Flue Gas Flowrate		31.67
O_2 Flue Gas Flowrate		10.33
N_2 Flue Gas Flowrate		199.31

Wood Calorific Value: In order to calculate the calorific value of the wood waste, the thermal power associated with each flue gas was calculated by determining the Higher Heating Value (HHV) of the flue gas components. The HHV is calculated by bringing the flue gas from the boiler outlet temperature down to 15 °C such that any water vapour is condensed, as per equation (4-4). Then, the total thermal power ($Q_{thermal}$) and its associated electrical power sent out ($P_{sent\ out}$) at a boiler efficiency (HHV_{eff}) of 36% (as per Table 4-1) were utilised to calculate the calorific value of wood (CV_{wood}), as shown in equations (4-1) to (4-3):

$$CV_{wood} = Q_{total\ (thermal)} / m_{fuel} \tag{4-1}$$

$$P_{sent\ out} = HHV_{eff}\ Q_{thermal} \tag{4-2}$$

$$Q_{thermal} = \dot{n}_w \Delta H_w^{vap} + \sum_{N_c} \dot{n}_i \Delta H_i \tag{4-3}$$

$$\Delta H_i = \int_{15\ °C}^{T_{boiler\ outlet}} C_{p,i} dT \tag{4-4}$$

where m_{fuel} is mass flow rate of fuel, n is molar flow rate of combustion gases, C_p is heat capacity, T is temperature, N_C is the number of components in the combustion gas, ΔH is change in enthalpy and ΔH^{vap} is the heat of vaporisation.

Mass flow rate of co-firing mixture: Co-firing ratios of 0%, 5% and 10% were calculated on a mass basis, so as to ensure energy sent out at each plant was maintained at pre-cofiring levels. A weighted sum of the calorific values of wood waste and coal, based on the co-firing ratio of wood (0%, 5% and 10%), was calculated to obtain the new calorific value of the co-firing mixture.

It is also assumed that an increase in co-firing ratio would result in a decrease in plant efficiency due to decreases in DCOW boiler efficiency and higher energy requirements associated with handling fibrous raw biomass (Khorshidi, Ho and Wiley, 2013). Cuellar developed a model to determine efficiency loss as a function of co-firing ratio, revealing a 0.5% overall efficiency loss (HHV%) for 5% co-firing and a 0.8% overall efficiency loss for 10% co-firing (Cuellar, 2012). This results in a system HHV efficiency of 35.5% and 35.2% for 5% and 10% co-firing respectively. To obtain the total fuel required ($m_{total\ fuel}$), the required energy sent out (500 MW for the base plant) is divided by the energy output per kg of co-firing mixture as shown in equation (4-5). The mass of DCOW and coal were obtained by multiplying the total fuel consumption by the co-firing ratio (CR), as per equation (4-6).

$$m_{total\ fuel} = \frac{P_{sent\ out}}{HHV_{eff,co-firing}\ CV_{co-firing}} \tag{4-5}$$

$$m_{co-firing\ DCOW} = CR \times m_{total\ fuel} \tag{4-6}$$

Flue Gas Composition: Based on the boiler conditions and the ratio of coal and DCOW (wood and paper consumed) at each co-firing level, the flue gas composition of each co-firing ratio was determined by means of a mass balance. The output emissions for each co-firing mixture were calculated using the ratio of base operating conditions and the actual operating conditions, for both the coal boiler and DCOW boiler. The base coal values as shown in Table 4-1 were utilised in equation (4-7). The base DCOW values as shown in Table 4-2 were utilised in equation (4-8).

$$n_{CO_2(co-firing\ Coal)} = \frac{n_{CO_2(base\ Coal)}}{m_{\ base\ Coal}} m_{co-firing\ Coal} \tag{4-7}$$

$$n_{CO_2(co-firing\ DCOW)} = \frac{n_{CO_2(base\ DCOW)}}{m_{\ base\ DCOW}} m_{co-firing\ DCOW} \tag{4-8}$$

Equations (4-7) and (4-8) were similarly employed for the other flue gas components (H_2O, O_2 and N_2). The molar composition of the flue gases at each of the co-firing levels are shown in Table 4-3.

Table 4-3: Flue gas molar composition at 0, 5 and 10% co-firing levels

Flue Gas Component (%mol)	Co-firing ratio (%mass)		
	0	5	10
CO_2	13.96	13.98	14.00
H_2O	6.72	6.90	7.10
O_2	3.91	3.90	3.89
N_2	75.41	75.21	75.01

Results

Figure 4-2 shows the actual and net emissions intensity for each co-firing scenario without CCS, assuming a 500 MW power output. The actual emissions represent the CO_2 emitted from both coal and DCOW combustion while the net emissions represent only the CO_2 emitted from coal combustion. It can be seen that as the co-firing ratio increases, so does the actual emissions intensity. This is attributable to the higher emissions intensity associated with wood than with coal (Khorshidi, Ho and Wiley, 2014).

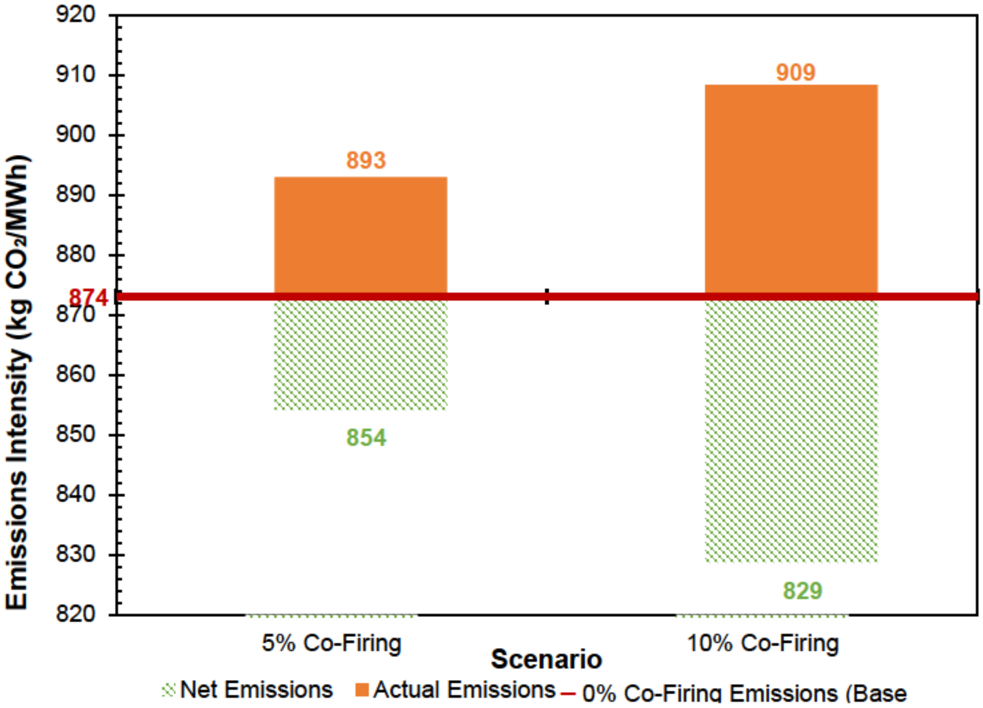

Figure 4-2: Emission Intensity at 5 and 10% co-firing levels without capture against 0% co-firing case

The net emissions intensity, however, decreases as co-firing ratio increases. This is because emissions from biomass as 'biogenic CO_2' is considered to be 'carbon neutral' with a zero GWP factor by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (Intergovernmental Panel on Climate Change, 2006). This was verified by calculating the amount of landfill gas (CH_4) diverted per co-firing scenario. In order to calculate the CO_2 equivalent, equation (4-9) was used (Department of the Environment and Energy, 2019):

$$CH_4(tCO_2e^-) = \{(Q \times DOC \times DOC_f \times F \times 1.336) \times (1 - OX)\} \times 25 \qquad (4\text{-}9)$$

The variables in equation (4-9) are described in Table 4-4.

Table 4-4: Parameters for Equation (4-9) (Department of the Environment and Energy, 2019):

Symbol	Description	Value	
		Wood	Paper
Q	Mass of waste disposed per year	Varies with co-firing scenario	
DOC	Degradable organic carbon in year of deposition	0.4	0.43
DOC_F	Fraction of DOC that can decompose	0.49	0.1
F	Fraction of CH_4 by volume, in generated landfill gas	0.5	
	Conversion rate of carbon to methane	1.336	
OX	Oxidation factor for default covered, well managed landfill	0.1	
	CH_4 global warming potential for conversion to CO_2	25	

A comparison of combustion emissions and landfill gas avoided for wood and paper is shown in Table 4-5. Due to the negligible difference of 0.06% between combustion and landfill emissions, it was assumed that any CO_2 generated due to burning wood or paper was 'carbon neutral'.

Table 4-5: Comparison of Combustion and Landfill Emissions for Wood and Paper used in co-firing

Emissions Type (tCO_2/h)	Co-Firing Ratio	
	5%	10%
Combustion	19.41	39.77
Landfill Gas	19.43	39.79
Difference	0.06%	0.06%

4.1.3 Emissions Reduction

The estimates for CO_2 emissions reduction and the energy use due to capture, transport and storage of CO_2, were calculated using ICCSEM. This model simulates the CCS chain in order to estimate process flows, equipment sizing and process economics. The capture and transport system were assumed to be parasitic, hence any extra power required is assumed to be derived from the base power plant.

Capture: In simulating CO_2 capture, a monoethanolamine (MEA) solvent absorption process is assumed. MEA was selected as it is a well-proven and commercially ready CO_2 capture technology with several desirable characteristics, including low-cost reagents, high operating capacity, fast reaction kinetics, and low retrofitting costs (Schakel *et al.*, 2014). MEA carbon capture works by feeding the flue-gas from fuel combustion through the bottom of an absorber, where the CO_2 in the gas is selectively absorbed by a cold-lean MEA stream that enters from the top. The rich MEA stream is passed through a stripper to regenerate a lean-MEA stream, and the resulting CO_2 gas exists the top of the column. It is assumed that the capture process is designed such that 90% of the CO_2 in the flue-gas sent to absorption is removed for sequestration, with the remaining 10% leaving in the gas discharged to the atmosphere. In addition to MEA, supplementary sodium hydroxide (NaOH) and activated carbon are respectively required to partially regenerate the consumed reagent and remove products of chemical degradation (Singh, Strømman and Hertwich, 2011)

Transport: For transport, in addition to boosters at the extremities of the pipelines it is assumed there are booster stations dividing the pipeline into segments and ensuring CO_2 is maintained at supercritical conditions and within pipeline pressure limitations (8-15 MPa) while optimising the cost of transport (Neal, Cinar and Allinson, 2013). The distance from the base case power plant to the storage site was assumed to be 858 km, reflecting the average distance from Mt Piper, Bayswater and Eraring to a storage site in the Darling basin. Additionally, for the base case only a single pipeline pathway was assumed. At the point of injection, it is assumed that the CO_2 in the pipeline is recompressed to the required top-hole pressure for sequestration.

Storage: As discussed in Section 2.3.1 and shown in Table 2-5, the CO_2 storage site chosen was the Pondie Range Trough in the Darling Basin.

Energy Requirements

The energy requirements for CCS (heat for solvent regeneration and electricity for gas blowers and CO_2 compression) were estimated using ICCSEM, as detailed above. The energy requirements for biomass pulverisation including primary and secondary grinding was assumed to be 150 kWh/t of waste processed (Esteban and Carrasco, 2006), obtained parasitically from the power plant. The energy penalty of these cases was calculated using equation (4-10).

$$EP = \frac{Energy\ due\ to\ CCS\ and\ pulverisation}{Initial\ Plant\ Capacity} \tag{4-10}$$

The energy requirements for biomass pulverisation, carbon capture, transport and storage for each of the co-firing cases is shown in Table 4-6 with a graphical breakdown shown in Figure 4-3. The largest contributor to the energy penalty is the capture unit, with solvent regeneration specifically requiring the most energy. The energy penalty for all cases ranges between 31-33%, increasing by 1.1% for 5% co-firing and a further 0.9% for 10% co-firing, to 32.95%.

Table 4-6: Energy requirements for 500 MW plant BECCS at various co-firing levels

Process	Unit	Co-Firing Ratio		
		0%	5%	10%
Biomass Pulveriser	MW	-	1.62	3.32
Capture				
Solvent Regeneration	MW	79.89	81.70	83.09
Solvent Capture	MW	4.21	4.31	4.38
Separation Compression	MW	14.86	15.18	15.42
NOx Removal	MW	8.18	8.35	8.48
SOx Removal	MW	4.50	4.60	4.67
Transport				
Initial Transport Compression	MW	35.12	36.01	36.70
Booster 1	MW	1.21	1.28	1.34
Booster 2	MW	1.21	1.28	1.34
Booster 3	MW	1.21	1.28	1.34
Booster 4	MW	1.21	1.28	1.34
Booster 5	MW	1.21	1.28	1.34
Booster 6	MW	1.21	1.28	1.34
Injection	MW	0.62	0.64	0.66
Total Power Requirement	MW	154.62	160.08	164.74
Energy Penalty	%	30.92	32.02	32.95

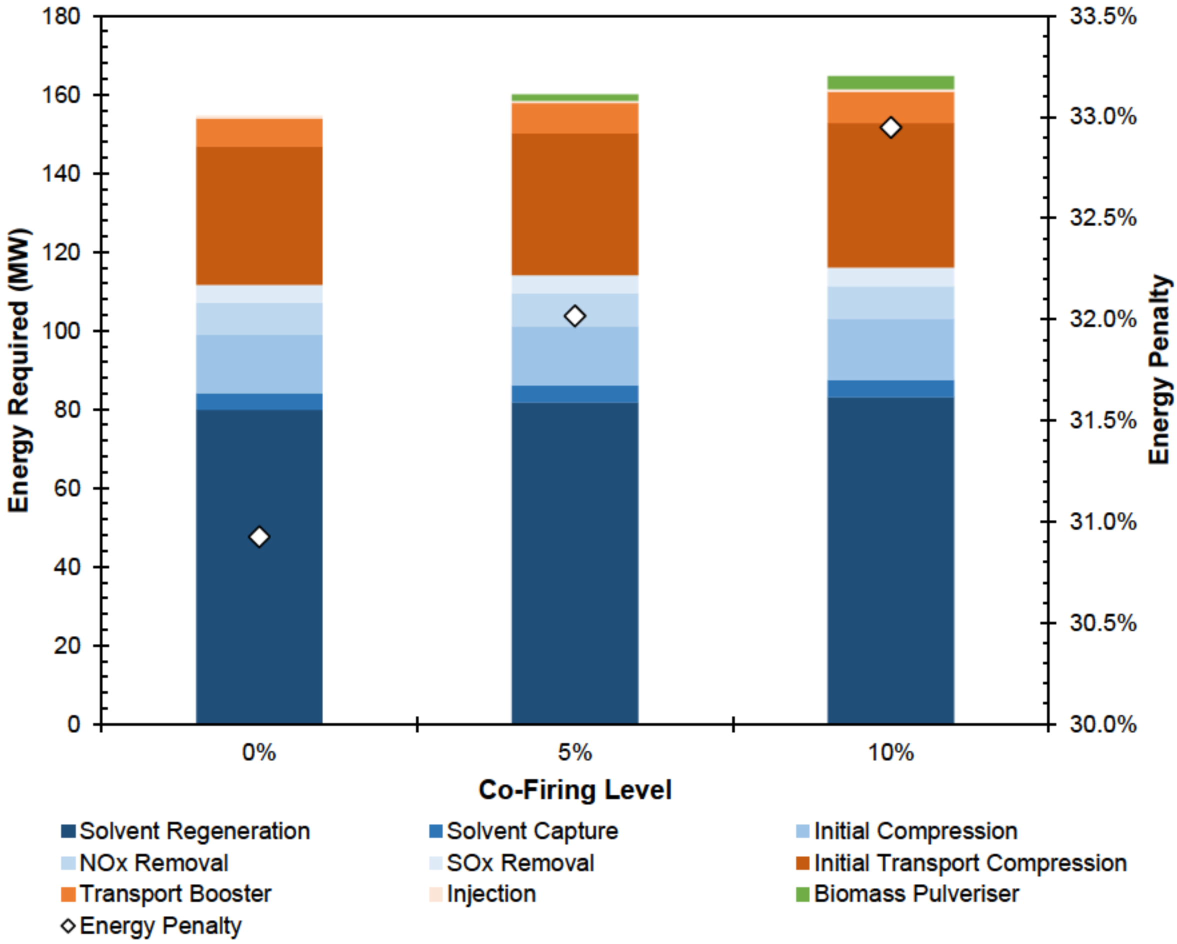

Figure 4-3: Energy requirement breakdown for 500 MW Base Plant at various co-firing levels

Emissions Intensity

The emissions intensity (*EI*) for each of the cases reported in units tCO_2/MWh was calculated using Equation (4-11) to (4-13), utilising the parameters shown in Table 4-7.

$$EI\ (Actual_{CCS/No-CCS}) = \frac{Emissions\ Output\ (Coal + Wood + Paper)}{Energy\ Sent\ Out} \tag{4-11}$$

$$EI\ (Net_{No-CCS}) = \frac{Emissions\ Output\ (Coal)}{Energy\ Sent\ Out} \tag{4-12}$$

$$EI\ (Net_{CCS}) = \frac{Emissions\ Output\ [(Coal + Wood + Paper)_{CCS} - (Wood + Paper)_{No-CCS}]}{Energy\ Sent\ Out} \tag{4-13}$$

For the net emissions with CCS, the total emissions associated with the waste combustion are subtracted from the actual emissions, as that fuel is considered carbon-neutral.

The energy sent out for all the cases is shown in Table 4-7. While biomass consumption was calculated to ensure that the energy sent out was maintained at a pre-BECCS level of 500 MW, since the BECCS systems are parasitic in nature the energy sent out is reduced by the electricity needed for the BECCS system. This includes the power requirements for CCS and the power requirements for biomass pulverisation as applied to all cases, including the no-CCS cases.

Table 4-7: Emissions intensity inputs for 500 MW power plant cases

Parameter		Unit	Co-Firing Ratio/Scenario					
			0%		5%		10%	
			No-CCS	CCS	No-CCS	CCS	No-CCS	CCS
Energy Sent Out		MW	500	345	498	340	497	335
Emissions Output	Coal	tCO_2/h	437	44	427	43	415	41
	Wood + Paper		-	-	19	1.94	40	3.98

The actual and net emissions for the co-firing scenarios are shown in Table 4-8 and graphically in Figure 4-4. When CCS is applied to the base case (0%), the emissions intensity decreased by 86%. As the co-firing ratio increased for the no-CCS cases, the net emissions intensity decreased by a total of 4.6% (1.1% then further 3.5%) from 0% to 10% co-firing to 0.83 tCO_2/MWh. The greater reduction in emissions intensity for the 5 to 10% co-firing case is attributable to added factors such as the decline in boiler efficiency as co-firing ratio increases. Although a decrease in emissions intensity due to a decrease in boiler efficiency may seem counterintuitive, this is due to increased biomass fuel requirements which have a higher direct emissions density than coal. Coupled with CCS, the higher emission density of biomass lead to larger negative emissions, and ultimately to lower net emissions intensity.

Table 4-8: Actual and net emission for 500 MW power plant co-firing cases

Parameter	Unit	Co-Firing Ratio/Scenario					
		0%		5%		10%	
		No-CCS	CCS	No-CCS	CCS	No-CCS	CCS
Actual Emissions Intensity	tCO_2/MWh	0.87	0.13	0.90	0.13	0.91	0.14
Net Emissions Intensity		0.87	0.13	0.86	0.07	0.83	0.02

The largest observable decrease in emission intensity is between the 0% No-CCS case and the 10% CCS case, with the emissions intensity decreasing by 98% from 0.87 tCO_2/MWh to 0.02 tCO_2/MWh, with most of the reduction in emissions being attributable to CCS (see Figure 4-4). It should be observed that negative emissions intensity were not achieved with the 10% co-firing cases. Section 4.2.2 discusses the minimum co-firing ratio needed to achieve negative emissions in a life cycle analysis.

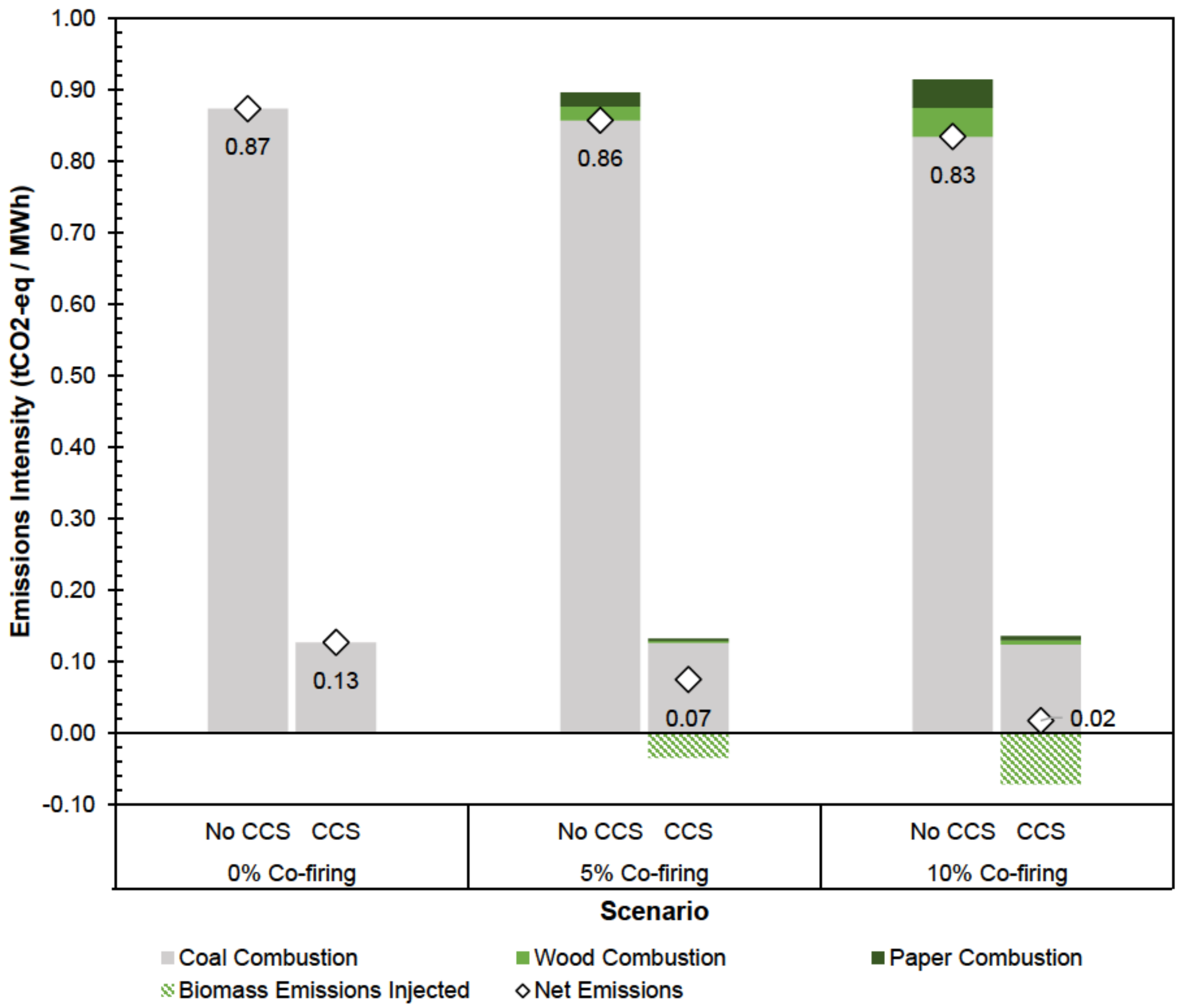

Figure 4-4: Emissions intensity (actual and net) for 500 MW power plant co-firing scenarios

4.1.4 Reduction in Landfill Usage

Waste Utilisation

As explained in Section 2.2.5, the waste category selected for BECCS utilisation was wood and paper from MSW and C&I waste in the Greater Metropole Sydney and Hunter and Newcastle LGAs. Table 4-9 shows the yearly fuel consumption rates for each of the co-firing scenarios. These values are compared against yearly waste disposal rates as reported in Table 2-4 to determine utilisation. As MSW, C&I and C&D waste are all landfilled, it is also useful to compare the DCOW utilisation rate against the total landfilled waste in NSW.

Table 4-9: Fuel consumption rate for 500 MW power plant cases, compared to DCOW availability in the Greater Metropole Sydney and Hunter and Newcastle LGAs (as per Table 2-4)

Material (t/y)	Co-Firing Ratio			DCOW Availability		
	0%	5%	10%	MSW	C&I	Total
Coal	1,840,336	1,800,101	1,746,649	-	-	-
Wood	-	47,371	97,036	18,549	263,684	282,233
Paper	-	47,371	97,036	270,063	277,689	547,752
Total	1,840,336	1,894,843	1,940,721	288,613	541,373	829,985

Table 4-10 shows the DCOW utilisation rates on a yearly mass basis for each co-firing scenario in a single 500 MW power plant unit against relevant mass categories. For the 5% co-firing case, 11% of eligible DCOW in NSW was utilised; this represented 0.5% of overall NSW waste (from MSW, C&I and C&D waste) which includes both combustible and non-combustible elements. Hence, a 5% DCOW co-firing level could be attained by no more than 8 power plant units of this type in NSW. Similarly, for the 10% co-firing case, 23% of eligible DCOW was utilised, representing 1.1% of overall NSW waste, which suggests that at most 4 power plant units could employ this level of DCOW co-firing in NSW.

Table 4-10: Proportion of eligible DCOW and overall waste utilisation for 500 MW power plant cases in NSW

Material	Co-Firing Ratio	
	5%	10%
Eligible Wood Waste (MSW+C&I)	16.8%	34.4%
Eligible Paper Waste (MSW+C&I)	8.6%	17.7%
Eligible DCOW (MSW+C&I)	11.4%	23.4%
Overall NSW waste (MSW+C&I+C&D)	0.5%	1.1%

Landfill Volume Reduction

The reduction in landfill volume for each co-firing scenario was calculated by converting the mass of waste consumed to its relevant landfill volume. The density used for wood was that of construction and demolition wood including painted, treated and clean lumber/wood at 100 kg/m^3 while the density for paper was that for printing paper and flattened cardboard containers at 192 kg/m^3 (U.S. Environmental Protection Agency, 2016). Assuming that the average density of all mixed landfill waste (MSW, C&I and C&I) is 207 kg/m^3 (U.S. Environmental Protection Agency, 2016), the total landfill volume used in NSW for all sources is 88.1 million m^3/year. The reduction in landfill volume usage in m^3 of landfill and its comparison to typical yearly landfill usage is shown in Table 4-11.

Table 4-11: Landfill volume reduction for 500 MW power plant cases

Material	Co-Firing Ratio	
	5%	10%
Wood (m^3/year)	473,710	970,360
Paper (m^3/year)	246,724	505,396
TOTAL (m^3/year)	720,434	1,475,756
Proportion of Total Landfill Volume Reduced (%)	0.82	1.67

4.2 Task 3.3: Life Cycle Analysis

This Section outlines the methodology and results for the life cycle analysis of emissions due to DCOW co-firing and implementation of CCS in NSW.

4.2.1 Methodology

The methodology for developing this life cycle model is based on ISO14040, the standardised methodology for undertaking an LCA.

Goal and Scope

The functional unit of an LCA should reflect the function of the end-product, and the purpose of the overall process. Because the purpose of combustion is to provide thermal or electrical power for consumption, energy-based products are primarily compared using functional units of energy (1 MWh, 1 kWh) (Shafie, Mahlia and Masjuki, 2013; Patel, Zhang and Kumar, 2016).The base case power plant (500 MW) was selected for the size of the power plant. This LCA therefore is not a case study of a specific power plant, but a representative study with average values used for Life Cycle Inventory (LCI) inputs based off values of actual power plants in NSW.

A "cradle-to-grave" scope is used for this LCA study, in line with international standards ISO14040 and ISO14044 (International Standards Organisation, 2006). In the context of coal-fired power generation, a "cradle-to-grave" scope includes the processes of extraction (mining), transportation, preparation, direct combustion, and disposal of waste products (predominantly coal bottom ash). For co-firing, additional waste transport, pulverisation and drying is accounted for in the material preparation stage to create a suitable fuel to feed to the boiler. In scenarios with CCS, the construction and operation of the absorber, stripper, compressor, and pipeline, as well as solvent production is accounted for. Finally, one of the novel aspects of this study is the characterisation of the biofuel from a waste source. Therefore, biogenic CO_2 (considered not to contribute to global warming due to being previously absorbed by plant growth) is considered to be 'avoided wood and paper to landfill'.

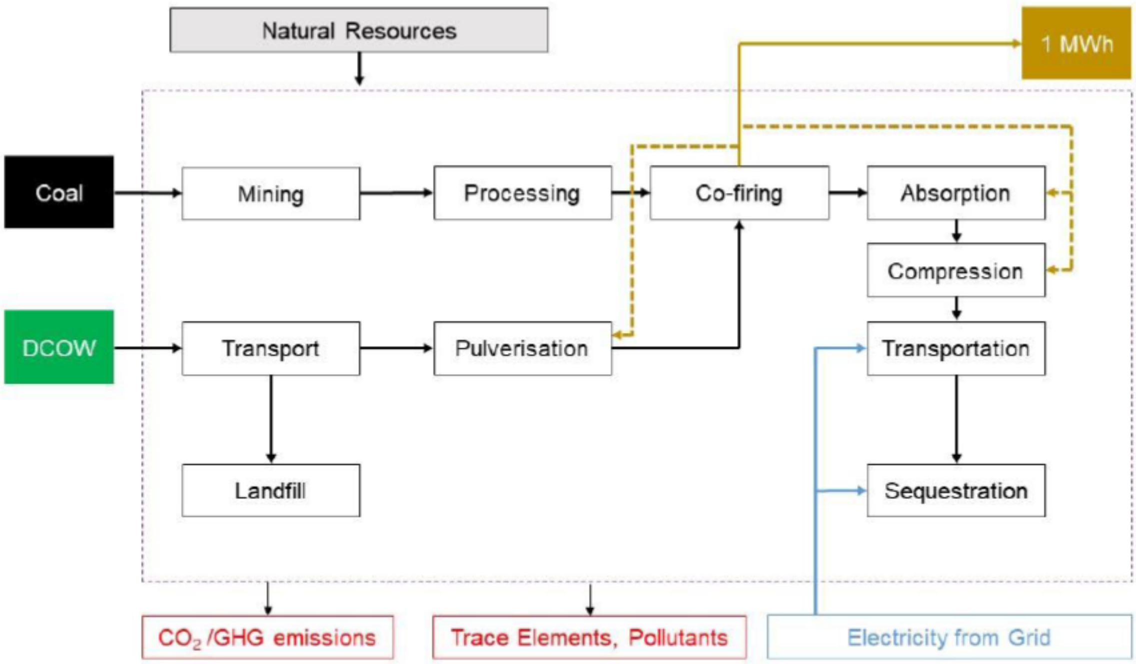

Figure 4-5: Scope of the LCA study

This study focuses on the energy generated at the power plant level sent to the grid, as efficiency losses of supplying electricity to the grid are the same in each scenario. A diagram of the LCA scope is presented in Figure 4-5, with the scenarios shown in Table 4-12.

Table 4-12: LCA Scenarios for Coal-DCOW co-firing

Scenario	Co-firing (%)	CCS	Fuel Required for 1 MWh net (kg)		
			Coal	Wood	Paper
1	0	Yes	563	-	-
2		No	395	-	-
3	5	Yes	549	14	14
4		No	383	10	10
5	10	Yes	533	30	30
6		No	370	21	21

Inventory Analysis

In the process of conducting an LCA, the assumptions and data used to build the model are referred to as the inventory stage (LCI) or the building of the inventory. Scenarios were modelled using SimaPro (v.9) software, developed by PRé Sustainability Group. Within SimaPro, the Eco-Invent database is used to account for general materials and processes in the life cycle.

Coal Assumptions

Emissions associated with the mining, treatment (prior to transport to power plant), and transportation of coal: the Australian Life Cycle Assessment Society (ALCAS) data for black coal in NSW was used.

Base Fuel: Bituminous coal was assumed as the base fuel for generating power.

Power Plant location to Mine: The location of the power plant was assumed to be within 30 km of the mine, requiring minimal transportation of the coal to the power plant.

Mass flow rate and composition of the flue-gas from the boiler: these are determined using combustion model data provided by Imperial College, London. The calorific value of the coal used was 23.8 MJ/kg representing an average of the coal used at Mt Piper, Eraring and Bayswater (Brown et al., 2006).

Co-firing Assumptions

Coal Transport: a mean transport distance of 20 km by rail and 10 km by conveyer was assumed, as this is the arrangement most commonly used at the NSW power plants of Mt Piper, Bayswater, and Eraring.

DCOW Transport: The assumed transport distance (173 km) of the DCOW from the landfill collection facilities is the averaged road distance between the Sydney CBD and the Mt Piper (161 km), Bayswater (235 km), and Eraring (124 km) power plants. Selecting the Sydney CBD as the DCOW source location is established on the fact that Sydney has the highest population density in NSW, and therefore is the area where the greatest proportion of DCOW will be recovered. Since most landfills are located outside of the CBD, using the distance between metropolitan Sydney rather than specific suburban landfill locations will result in a conservative estimate of the impact of emissions from transport.

Waste Sorting: It is assumed that the DCOW waste arrives at the facility sorted, with no emissions associated with separation, and no significant impurities to consider.

DCOW Pulverisation: A hog pulveriser is assumed, as there is a need to reduce the particle size from approximately 300 mm to 25 mm, and a fine pulveriser to further reduce mean particle size to 3 mm (Sebastián, Royo and Gómez, 2011).

Energy Supply: The energy is assumed to be supplied from the Australian power grid. Results are presented for a 500 MW plant and this study does not account for issues regarding scaling size increases; however, since results are reported in terms of a 1 MWh basis, the impact is negligible (Schakel *et al.*, 2014; Spath and Mann, 2004)

Trace Emissions: It is assumed that the power plant will be able to overcome the shortfall in efficiency by burning additional fuel for the co-firing and CCS cases, so that the total energy supplied to the grid remains constant. Emissions data was modelled in Section 3 for waste wood / coal fuel compositions of 0%, 5%, and 10% mass basis. This was used to determine trace emissions. At the calculated flow rates, it was determined that an electrostatic precipitator (ESP) is required, as mentioned in Section 3.2, and assumed to operate at 99% efficiency (Koornneef *et al.*, 2008). The total emissions from the reactor (boiler) were calculated using equation (4-14), where η_{ESP} is the efficiency of the electrostatic precipitator, C is the concentration of the trace element (mg/kg of flue), and m_{flue} is the mass flow rate of the flue gas.

$$\dot{m}_{trace} = (1 - \eta_{ESP}) \cdot C \cdot \dot{m}_{flue} \cdot \frac{1\,g}{10^3 mg} \tag{4-14}$$

In NSW, pollutant concentration limits are governed by the Environmental Protection Agency (NSW EPA) and listed in the respective Environmental Protection Licenses (EPLs) for each power plant (Mt Piper – 13007, Bayswater – 779, and Eraring, 1429). In the most recent revision of the licences, there is no limit on the concentration of SO_2 emissions, and a limit of 1,500 mg/m^3 for NO_x (Whelan, 2018) Consequently, de-NO_x units are not incorporated in any of the six base scenarios. Flue gas desulphurisation (FGD) units are considered in the CCS scenarios, as the formation of sulphuric acid could potentially damage the internals of the absorption column and stripper (Schakel *et al.*, 2014).

Data for the emission intensity of NO_x and SO_x for co-firing was assumed based on correlations observed in literature for biomass-coal co-firing and scaled relative to NO_x / SO_x emissions from Australian bituminous coal (Kazanc *et al.*, 2011). It is assumed that each additional percentage increase of biomass decreases the total NO_x output of the gas by 0.7% (Rokni *et al.*, 2018). It is assumed that the energy requirement of the FGD is negligible when compared with the power plant.

<u>Fouling and Slagging</u>: It is assumed there is negligible change in slagging and fouling from co-firing with DCOW, compared with coal-only combustion. Co-firing has been found to increase slagging and fouling in boilers due to a higher concentration of alkali metals and lower fuel melting temperature of biomass material, however this effect is minimal, in the order of 0.2% (Pour, 2018).

<u>Mass Balance</u>: Flow rate data estimated by Imperial College was modified due to discrepancies in flue-gas flow rates of CO_2 from the model and in literature (Annamalai, Thien and Sweeten, 2003). In recalculating the mass flow rates of flue-gas at different co-firing ratios, a mass balance was performed. The assumptions used in the mass balance are displayed below in Table 4-13 (and additional parameters in Table 4-14 and Table 4-15).

Table 4-13: Mass balance assumptions

Parameter	Value	Units
Project life	30	y
Plant availability	85	%
Emissions Intensity (Coal)	0.874	t CO_2 / MWh
Emissions Intensity (Wood and Paper)	1.080	t CO_2 / MWh
HHV Minimum Temperature	288.15	K
HHV (100% coal)	36.00	%
Flue Gas Molar Composition – Coal		
CO_2	13.96	%
H_2O	6.72	%
O_2	3.91	%
N_2	75.41	%
Flue Gas Molar Composition – Wood		
CO_2	14.46	%
H_2O	11.23	%
O_2	3.66	%
N_2	70.65	%
Efficiency Drops		
HHV Efficiency – 5% co-firing	35.50	%
HHV Efficiency – 10% co-firing	35.20	%

Table 4-14: LCI inventory for direct emissions (before capture) of CO_2 and trace elements (min 0.01 g/MWh)

Component	0%		5%		10%	
	No CCS	CCS	No CCS	CCS	No CCS	CCS
Major flue-gas components (kg/MWh) – CCS figures are unprocessed emissions						
CO_2	874	1245	894	1288	911	1322
H_2O	172	245	181	260	189	274
O_2	178	253	181	261	184	267
N_2	3003	4282	3062	4410	3105	4509
Particulate	15.44	22.02	15.46	22.27	15.48	22.48
SO_2	1.69	0.24	1.64	0.24	1.58	0.23
NO_x	1.90	2.71	1.88	2.70	1.84	2.67
Trace flue-gas components (g/MWh) – Emissions post ESP and FGD						
Si	16.17	23.05	15.94	22.95	15.60	22.66
Fe	2.89	4.12	2.86	4.11	2.80	4.07
Mg	0.72	1.03	0.69	0.99	0.64	0.93
Ti	0.34	0.48	0.36	0.58	0.39	0.57
Ca	0.28	0.39	0.31	0.52	0.39	0.57
K	0.16	0.22	0.16	0.45	0.35	0.51
Ba	0.10	0.14	0.10	0.23	0.16	0.24
Mn	0.05	0.07	0.06	0.15	0.11	0.15
P	0.03	0.04	0.03	0.08	0.06	0.09
V	0.02	0.03	0.02	0.04	0.03	0.04

Table 4-15: LCI data for coal, upstream coal processes, and DCOW characteristics

Component	Life Cycle Inventory Data		Reference
	Value	Units	
Coal			
Calorific Value	23.8	MJ/kg coal	CINSW
Mining, Transport, Pulverising Emissions	0.136	kg CO_2/kg coal	(Australian Life Cycle Assessment Society, 2019)
DCOW			
Wood-waste calorific value	16.62	MJ/kg wood waste	Calculated
Paper-waste calorific value	16.62	MJ/kg wood waste	
Transport	173	km	(Google Maps)
Hog Pulveriser energy requirement	160	MJ/t waste	(Sebastián, Royo and Gómez, 2011)
Fine pulveriser energy requirement	35	MJ/t waste	
Plant HHV Efficiencies			
Scenario 1: 0% co-firing – no CCS	36.0	%	Calculated
Scenario 2: 0% co-firing – with CCS	25.3	%	Calculated
Scenario 3: 5% co-firing – no CCS	35.5	%	Calculated, (Cuellar, 2012)
Scenario 4: 5% co-firing – with CCS	24.6	%	Calculated, (Cuellar, 2012)
Scenario 5: 10% co-firing – no CCS	35.1	%	Calculated, (Cuellar, 2012)
Scenario 6: 10% co-firing – with CCS	24.1	%	Calculated, (Cuellar, 2012)
Electrostatic precipitator (ESP) efficiency	99.0	%	(Koornneef *et al.*, 2008)
Efficiency Drop per co-firing % (for > 10% co-firing)	0.06	%	(Schakel *et al.*, 2014)

A full table of the LCI data for the six base scenarios is contained in the Appendix.

CCS Assumptions

Section 4.1.3 contains the relevant assumptions for the CCS process. Additional assumptions include:

Life cycle emissions for MEA, NaOH, and activated carbon: These were sourced directly from the Eco-Invent 3 database. Ammonia emissions from MEA regeneration were also accounted for.

Transport/Injection Energy Requirements: For the compressor at the plant at the start of the pipeline transportation, the work (W, in kJ/kgCO_2) and electricity (E, in kWh/kgCO_2) required for the compression of CO_2 gas was calculated via equations (4-15) and (4-16). The electrical energy for injection was also calculated this way. These equations account for compressibility (Z), isentropic efficiency (η_{is}), and mechanical efficiency (η_m) (IEAGHG, 2011).

$$W = \frac{ZRT}{M} \cdot \frac{N\gamma}{\gamma - 1} \cdot \left[\left(\frac{P_2}{P_1} \right)^{\frac{\gamma - 1}{N\gamma}} - 1 \right] \tag{4-15}$$

$$E = \frac{W}{\eta_{is} \cdot \eta_m \cdot 3600} \tag{4-16}$$

where R the universal gas constant, M the mean molar mass, N the number of compression stages, γ the ratio of heat capacity at constant pressure to constant volume and P is pressure.

The energy required to transport the captured CO_2 via pipeline was determined using the Integrated Carbon Capture and Storage Economics Model (ICCSEM). The energy required by the intermediate boosters and top-hole compressor is calculated based on the volumetric flow rate and molar composition of the flue gas. The model assumes an adiabatic system to calculate the work required for each compressor by solving for temperature and enthalpy that satisfy isentropic conditions. The number of boosters that gave the minimum overall cost for CO_2 transport was selected (found to be 10 for all three co-firing levels). Since the rate of CO_2 generation increases as more biomass is combusted, the energy required changes with the co-firing ratio. In the base cases, the electricity required for power generation is assumed to have emissions intensity representative of the average NSW grid.

Other Emissions: Emissions and environmental impacts of CCS capital outlay are distributed over the lifespan of the project (30 years) to obtain a resource consumption per MWh. It is assumed there is no social discount factor for future CO_2 emissions, a concept which some authors have argued against despite it being standard practice (Dyckhoff and Kasah, 2014). Due to the limited availability of data, emissions associated with maintenance, disposal, recycling, and waste processing of the pipe network are excluded. Based on these two principles, the emissions intensity of the CCS network construction is likely to be slightly underestimated. A summary of the LCI data for the CCS related components of the project is displayed in Table 4-16, including the relevant parameters for equation (4-17).

Mass of steel (M_s) in the pipeline is calculated in terms of its length (L), steel density (ρ), and cross-sectional area (A_c), which in turn depends on its outer diameter (D_o), and thickness (t):

$$M_s = \pi \cdot A_c \cdot L \cdot \rho = \left[\left(\frac{D_o}{2}\right)^2 - \left(\frac{D_o - 2t}{2}\right)^2\right] \pi \cdot L \cdot \rho \qquad (4\text{-}17)$$

Energy Penalty:

To incorporate the LCI effects of CCS into the power plants, sub-processes for CCS were modelled as inputs to the overall CCS process and scaled to a basis of 1 kg processed (input) CO_2. This overall CCS process was then modelled as an input to the functional unit of 1 MWh. Although in material balance terms the CCS is a downstream process to the combustion of fuel for electricity, for the LCA scenario it must be considered as an input to the process. To account for the carbon sequestration component of the overall process, a value of -0.9 kg was entered for CO_2 emissions to atmosphere. This reflects the 90% capture efficiency of carbon dioxide.

Table 4-16: LCI for CCS

Component	Value	Units	Reference
Capture – energy requirements			
CO_2 capture efficiency	90	%	(Nawshad and Cottrell, 2014)
SO_2 capture efficiency	90	%	
Wash water pump	0.01	kWh/t of CO_2 processed	
Rich solvent pump	0.39	kWh/t of CO_2 processed	
Blower	0.84	kWh/t of CO_2 processed	
Stripper energy	217.00	kWh/t of CO_2 processed	
Capture –emissions to environment			
Ammonia (NH_3)	0.021	kg NH_3/t CO_2 processed	(Nawshad and Cottrell, 2014)
Capture – consumption of chemicals			
Activated carbon (AC)	0.075	kg AC /kg CO_2 processed	(Nawshad and Cottrell, 2014)
Ammonia (NH_3)	0.13	kg NH_3 /kg CO_2 processed	
MEA	2.34	kg MEA/kg CO_2 processed	
Sodium hydroxide (NaOH)	0.13	kg NaOH/kg CO_2 processed	
Compression - electricity requirements equations (4-15) and (4-16)			
Compressibility factor (Z)	0.9942	-	(IEAGHG, 2011)
Universal gas constant (R)	8.3145	J/mol K	
Suction temperature (T_1)	313.15	K	
Molecular mass (M)	44.01	g/mol	
Suction Pressure (P_1)	0.1013	MPa	
Discharge Pressure (P_2)	11	MPa	
Specific heat ratio (γ)	1.2938	-	
Compressor stages (N)	4		
Isentropic efficiency (η_{is})	80	%	
Mechanical efficiency (η_m)	99	%	
Transportation Stage			
Pipeline distance	850	km	
Pipeline diameter	300	mm	From ICCSEM
Pipeline wall thickness	8.53	mm	From ICCSEM
Steel (pipelines)	59,000	t	Calculated
Density of steel	7850	kg / m^3	
Diesel	1,673,100	t/km of pipeline	(Wildbolz, 2007)
Transport (Lorry)	315,000	tkm /km of pipeline	
Transport (Rail)	55100	tkm /km of pipeline	
Rockwool	2521	t/km of pipeline	
Plant lifetime	30	years	
Total energy output (MWh)	131,400,000	MWh	
Transportation Stage (MW electricity required for transport and tophole compressor, accounting for efficiency)			
0% co-firing CCS	12.414	MW	From ICCSEM
5% co-firing CCS	13.513	MW	From ICCSEM
10% co-firing CCS	14.175	MW	From ICCSEM

In a BECCS retrofitting arrangement, the energy required for carbon capture and biofuel material pulverization is assumed to be provided by the plant. Hence, this requires an 'energy penalty' (E_p) to be applied to the system, as the sum of the absorption and stripping ($E_{capture}$), compression ($E_{compression}$), and biomass pulverisation ($E_{pulverise}$) energy requirements, as per Equation (4-18). The energy penalty for compression and absorption is proportional to the flow of CO_2 pre-capture, and the energy penalty for biomass pulverisation is proportional to the total mass of wood and paper. To obtain the adjusted emissions, the base-case emissions for each co-firing level are divided by the difference between 1 MWh and the proportional energy penalty – equation (4-19).

$$E_p = \dot{m_{CO_2}} \left(E_{capture} + E_{compression}\right) + E_{pulverise} \tag{4-18}$$

$$Fuel_{1\,MWh} = \frac{Fuel_{ref}}{(1 - E_p)} \tag{4-19}$$

The approach of this study was considered to be valid and accurate, given that the results are consistent with published efficiency drops from BECCS and CCS retrofitting, such as those from Schakel *et al.* (2014) and Kornneef (IEAGHG, 2011) who reported energy penalties of between 29-34% when CCS was retrofitted to an existing pulverised coal-firing system.

For capital outlays, the total quantity of materials utilised are distributed across the lifespan of the plant. The total energy output of the plant (in MWh) can be determined by assuming an operating lifespan, converting to hours, assuming 85% availability due to planned and unplanned shut downs, and then multiplying this by the plant power output (500 MW). Each of the total material requirements for the CCS pipeline network displayed in Table 4-16 are divided by the total energy output over the plant lifetime, calculated in Equation (4-20). Due to limited availability of data, emissions associated with the recycling and disposal of the CCS network are not included, meaning that the total environmental impact attributed to the capital construction of CCS will likely be understated. Furthermore, leakages of CO_2 from the pipeline are assumed to be negligible, with an emissions leakage of less than 0.004% of total CO_2 transported (Kornneef, 2008).

$$E_{lifetime} = 500\,MW \cdot \left(30\,yr \cdot \frac{365\,day}{yr} \cdot \frac{24h}{day} \cdot 85\%\right) = 1.1 \cdot 10^8 MWh \tag{4-20}$$

In the construction of CCS pipelines, low-alloyed carbon steel is the preferred material of construction, as the moisture content of the sequestered gas is well below the 580 ppm threshold to enable corrosive behaviour from carbonic acid. Rock wool was selected as the material for pipeline insulation, with a thickness of 30 mm. Emissions associated with the diesel and machinery were scaled up based on material values per kilometre of pipeline obtained from Wildbolz (2007).

Landfilling Assumptions

The data associated with landfilling was compiled using Eco-Invent (ecoinvent, 2019). The emissions associated with avoiding 1 kg of wood waste and paper waste were considered 'avoided products'. The EcoInvent-3 database in SimaPro has an inbuilt landfill disposal scenario for wood and wood wastes, which was utilised for the avoided emissions for the purposes of this study. In Australia, only 11% of landfills have a landfill gas (LFG) system to collect methane for power generation through on-site combustion. However, this practice is commonplace in larger-scale landfills, particularly those nearer to metropolitan Sydney. Hence, it is assumed that a proportion of methane emitted during the degradation of DCOW is captured and flared. The Eco-Invent process "Waste treatment, wood and wood waste, at landfill" assumes that for every 1 kg of landfilled wood-waste, 0.0287 kg of methane is flared and utilised for power generation. Assuming total methane emissions of 0.0335 kg of methane per kg of DCOW (ecoinvent, 2019), this corresponds to a methane capture efficiency of 85.7%.

Impact Assessment and Characterisation

The focus of this report is to investigate the emissions reduction capacity of co-firing with BECCS to deliver negative CO_2 emissions. Therefore, the primary impact assessment methodology used has a focus on GHG emissions accounting. The IPCC 2013 GHG methodology was chosen, which is based on the Fifth Assessment Report (AR5) by the IPCC and includes the most recent data for global warming potentials for different substances.

4.2.2 Results

This Section analyses the six scenarios in terms of life cycle global warming potential (GWP, in terms of CO_2-equivalent emissions), and the processes in these scenarios driving the changes in GWP. Emissions intensity is reported in units of kg $CO_{2\text{-eq}}$ / MWh, directly relating the relevant characterisation factor to the functional unit. This Section also includes additional scenarios simulated at co-firing ratios higher than 10%, to determine the minimum co-firing ratio required for negative emissions. Scenario 1 is referred to as the 'base–case' scenario, as this case employs neither co-firing nor CCS, consistent with current practices at NSW coal-fired power plants.

Results of $CO_{2\text{-eq}}$ analysis

The life cycle CO_2 emissions for each of the six base cases are displayed in Table 4-17. The base-case emissions intensity (Scenario 1: 0% co-firing without CCS) is 938 kg $CO_{2\text{-eq}}$ / MWh.

Without CCS, co-firing at 5% and 10% reduces lifecycle CO_2 emissions to 930 and 917 kg CO_2 / MWh respectively. Since increasing the co-firing ratio decreases net emissions, this implies the increase in avoided emissions exceeds the proportional increase in waste transportation and compression. There is a greater reduction in GWP from 5 to 10% co-firing than 0 to 5% co-firing. This is due to the decline in HHV and boiler efficiency as co-firing ratio increases, which leads to larger biomass requirements per unit power produced, and thus more negative emissions. To keep net electrical output constant, the total quantity of biomass burned must increase proportionally more than the increase in co-firing.

Table 4-17: Total life cycle GHG emissions by process (kg $CO_{2\text{-}eq}$ / MWh)

Scenario		**Contribution to Life Cycle GHG emissions (kg $CO_{2\text{-}eq}$ / MWh)**					
Co-firing Ratio	Capture	Direct Combustion	Coal Mining & Transport	Pipeline Operation	Remaining Processes	Negative Emissions	Total Emissions
0%	No-CCS	874	50	0	14	-	**938**
	CCS	103	72	22	56	-	**253**
5%	No-CCS	894	49	0	17	-30	**930**
	CCS	105	72	24	62	-43	**219**
10%	No-CCS	911	48	0	20	-62	**917**
	CCS	107	70	25	67	-89	**181**

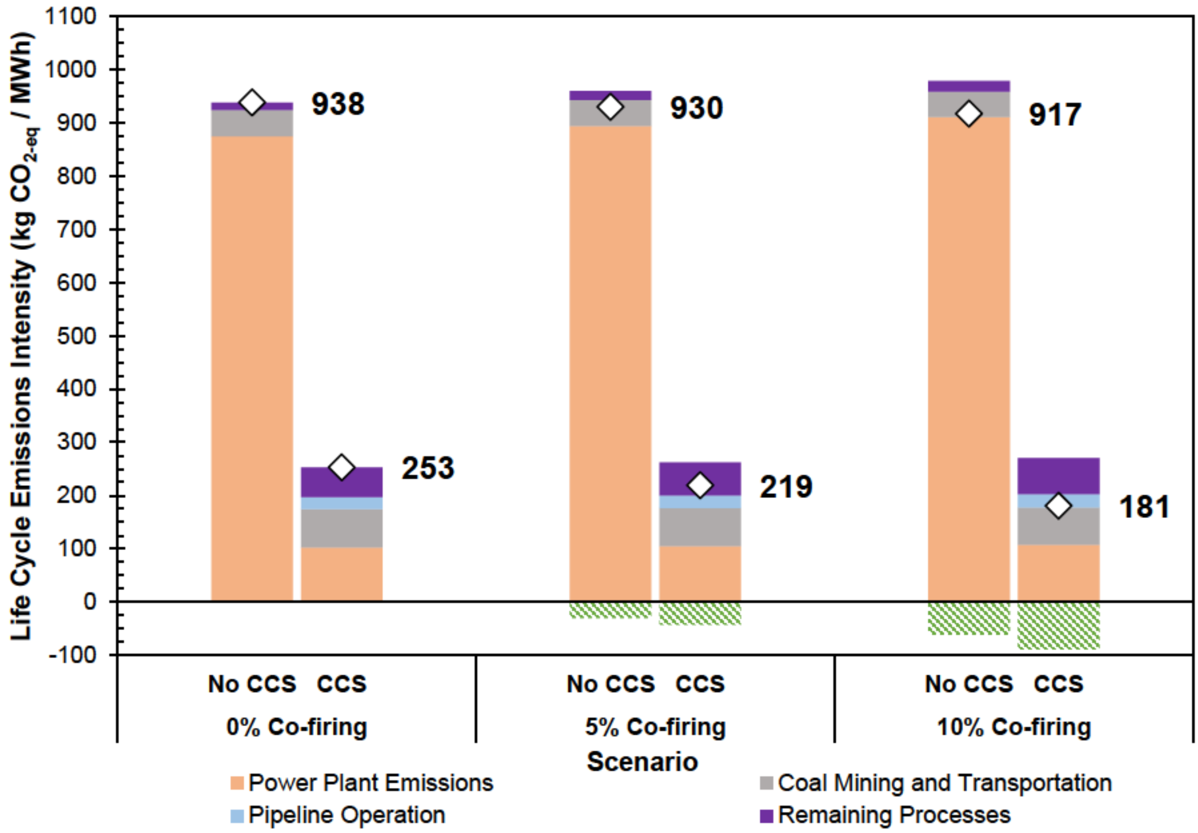

Figure 4-6: Life cycle GWP (kg CO_2 / MWh) for each of the six scenarios

When CCS is applied to the base case scenario, life cycle emissions decrease by 73% to 253 kg CO_2 / MWh. This is comparable to reductions found by Schakel (74%), Yang (77%) and Odeh (74%) (Odeh and Cockerill, 2008; Schakel *et al.*, 2014; Yang *et al.*, 2019). Increasing the co-firing ratio also reduces life cycle emissions intensity for the CCS scenarios. Increasing co-firing to 5% decreases life cycle emissions by 13% (219 kg CO_2 / MWh). Increasing co-firing from 5% to 10% decreases co-firing by 17% (181 kg CO_2 / MWh). The difference in GWP between the most and least CO_2 intensive scenarios (Scenario 1 and Scenario 6; 0% without CCS vs 10% with CCS) is 81%. A graphical display of the results is shown in Figure 4-6.

In co-firing scenarios without CCS (1, 3, and 5), life cycle emissions are dominated by direct emissions from fuel combustion at the power plant (93% of GHGs), with the next most significant process being the emissions associated with extracting coal (5%). At 10% co-firing, GHG emissions from the transport of biomass to the plant contribute less than 0.3% (1.56 kg CO_2 / MWh) to life cycle GWP. The energy required at the plant to pulverise the biomass for combustion only imposes an energy penalty of 0.2%. This translates to a GHG contribution of less than 0.8 kg CO_2 / MWh.

When CCS is employed, direct combustion emissions are drastically reduced, causing ancillary processes to account for a larger share of GHGs. Coal mining accounts for 26 – 28% of emissions (less at higher co-firing ratios). Biomass transportation accounts for 1.2% of GHG emissions. The increase in emissions share of supporting processes is amplified by the increased consumption of coal to overcome the capture and compression energy penalty, and the emissions from power plants providing the electricity for CO_2 pipeline compression. The increase in the quantity of fuel required also increases emissions from having to transport more DCOW and dispose of more bottom ash.

One distinguishing feature of this study is the lower upstream emissions for the biomass in co-firing. Since the scope of this study utilises waste as an input, the only the upstream emissions for biomass are transport and pulverisation. Most BECCS co-firing studies use dedicated biomass farmed for co-firing. Consequently, upstream emissions increase as a result of the energy and materials used in growing the crops. Co-firing switchgrass and coal at ratios over 30%, can add over 50% to life cycle emissions due to N_2O from fertilisers and the energy required to dry and pulverise the biomass (Yang *et al.*, 2019). Additionally, using local or domestic waste limits the emissions resulting from biomass transportation. The emissions intensity from transport in this study contrast starkly to those of Basu, Butler and Leon, (2011) who attribute 160 kg CO_2 / MWh to emissions from transport (due to procuring foreign biomass which is shipped 15,000 km).

The other unique aspect of this study relative to other BECCS LCAs is accounting for the disposal of coal bottom ash to landfill. In Australia and in many European countries, bottom ash is often utilised in concrete production, and hence, is not counted as a waste flow to the environment. In non-CCS cases, bottom ash contributes 5.8 – 5.5 kg CO_2 / MWh. In CCS cases, GHG from ash production increases to 8.2 – 8.0 kg CO_2 / MWh. The lower end of these ranges correspond to the higher co-firing ratios, because the GWP of coal bottom ash is higher than that of wood.

Minimum co-firing ratio required for negative emissions

As the co-firing ratio increases, life cycle GWP decreases. For scenarios that employ CCS, as the co-firing ratio increases from 0%, to 5%, to 10%, GWP decreases from 253, to 219, to 181 kg CO_2 / MWh. This trend suggests there exists a co-firing ratio which, when combined with CCS, can deliver net negative emissions. Identifying the minimum co-firing ratio required can give power plants a minimum target of DCOW to aim for, to avoid lowering HHV efficiency more than necessary, whilst still being able to deliver negative emissions.

Solving for a minimum co-firing ratio analytically using SimaPro is not possible. Therefore, multiple scenarios are required for simulation over a domain of different co-firing ratios. Holding HHV and CCS absorption and compression efficiencies constant, additional simulations at co-firing ratios from 10% to 40% were performed, in 5% co-firing increments. Plotting life cycle CO_2 emissions against co-firing ratio and fitting these results to a trend allows for calculation of a co-firing ratio at which negative emissions are possible.

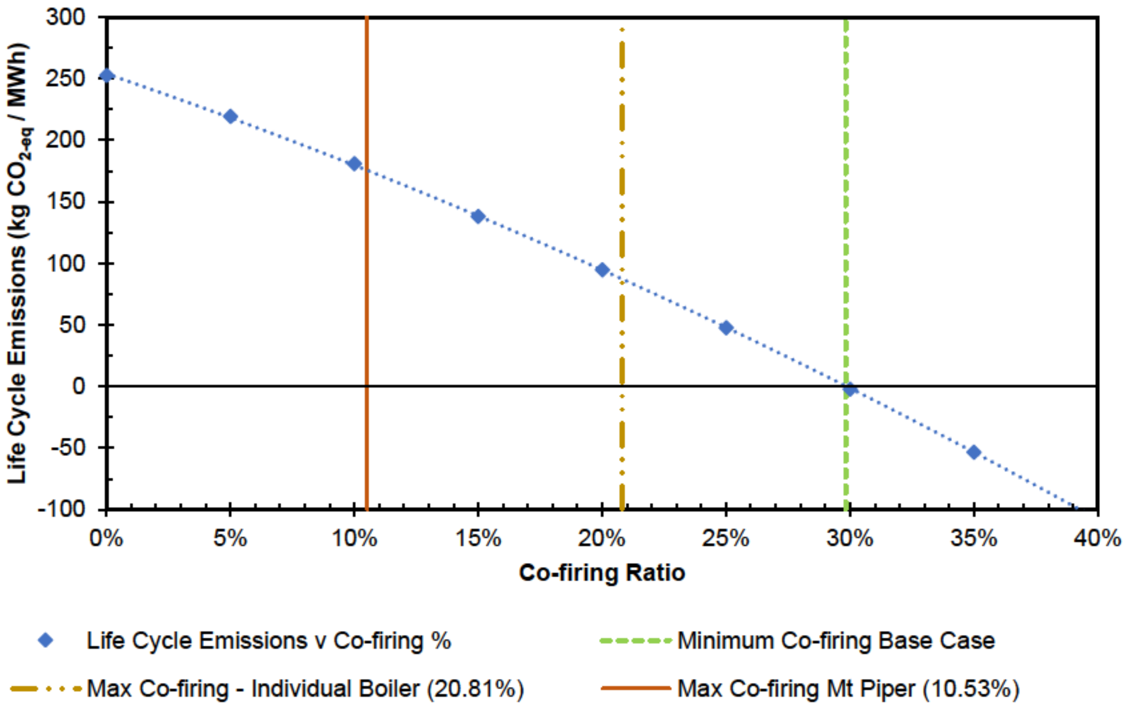

Figure 4-7: Life Cycle GWP at different co-firing ratios

The results of simulating co-firing ratios from 0% to 40% are displayed in Figure 4-7. Each additional percentage increase in co-firing leads to a greater than proportional decrease in GWP. Hence, a second-order polynomial curve was fitted to the data. Solving this trend produced a minimum co-firing ratio of 29.8% required for negative emissions. As expected, this value is relatively higher than some reported figures from LCA studies of biomass co-firing (Gough and Upham, 2010; Schakel *et al.*, 2014), attributed to the slightly lower HHV of coal and DCOW, the long transport distances demanded of the CO_2 pipeline in NSW, and including bottom-ash production in calculating GWP. Nonetheless, this co-firing ratio is similar to other co-firing percentages identified for negative emissions, such as the 31.3% by Spath and Mann (2004).

Although theoretically possible, based on the current quantity of nominated biomass (landfilled DCOW) available, a co-firing ratio of 30% is not achievable. An annual DCOW availability of 830 kt equates to a maximum consumption of 95,000 kg/h. This supply of biomass is far short of the fuel demanded by a typical NSW coal-fired power plant such as, for example, Mt Piper at 1,400 MW, (AEMO, 2019) to achieve a 30% co-firing ratio. Table 4-18 lists the fuel consumption required to achieve co-firing ratios from 5% to 40% at different power plant capacities.

Table 4-18: DCOW required at different capacity power plants

Co-firing Ratio (%)	DCOW Required (kg / MWh)	DCOW Required to Implement (kg / h)		
		500 MW	660 MW	1,400 MW
5	31	15,469	20,419	43,312
10	64	31,980	42,214	89,545
15	99	49,624	65,504	138,947
20	137	68,499	90,419	191,798
25	177	88,718	117,107	248,409
30	221	110,403	145,732	309,128
35	267	133,694	176,476	374,344
40	317	158,749	209,549	444,497
Max. Co-firing Ratio (%)		26.4%	20.8%	10.5%

The hypothetical 500 MW power plant examined in the LCA can achieve a maximum co-firing ratio of 26.4%. An individual boiler at Bayswater has a capacity of 660 MW, reducing the maximum co-firing achievable to 20.8% due to biomass availability. At Mt Piper, the second-smallest coal-fired power plant in NSW, a maximum co-firing ratio of 10.53% is possible. It should be noted these figures are based on a 100% recovery rate of available DCOW – in actuality, due to issues with sorting and waste procurement, the quantity of waste available for co-firing is likely to be overstated, meaning that the maximum feasible co-firing ratios achievable for each of the three scenarios are likely to be lower.

This analysis shows that the current quantity of DCOW available for combustion is a constraint on achieving negative emissions. This warrants further investigation into the effect of other baseline assumptions made in the LCA on life cycle emissions.

5 Task 4: Techno-Economic Analysis

5.1 Task 4.1 and 4.2: Identify changes to key operating characteristics and patterns of a conventional coal plant under varying levels of future renewable penetration when challenging fuels are used.

5.1.1 Operational implications of alternate fuel types

As mentioned in Sections 2 and 4, waste fuel inputs are limited by factors including waste availability and the high impurity and non-organic make up of other waste fuels such as domestic waste. In this scoping study, wood and paper from MSW and C&I waste (DCOW) are considered. Possible challenges faced in the use of DCOW are primarily concerns about sorting to ensure low impurities. Currently the primary source of waste recovery is through Materials Recovery Facilities (MRFs) which are operated by private businesses contracted to local government (Australian Government, 2018). The highest DCOW recycling rates are reported by the construction, industrial and demolition waste industries accounting for 80% of all recycled waste (Australian Government, 2018). Several studies have suggested including technological improvements in robotic and optical sorting, increased infrastructure for C&I recycling and increasing awareness regarding organic waste recycling including soil (Environment Protection Authority, 2014; Australian Government, 2018). With waste recycling rates being 21% and overwhelming landfill diversion, improvements in recycling strategies are needed before DCOW is a feasible fuel for BECCS usage.

Other possible bio-fuel options include landfill gas, which still falls in the MSW category, wood and forest residue, herbaceous and agricultural waste and aquatic waste. The ash content of each of these fuels is a key consideration, with high ash content fuels leading to fouling and slagging in boiler equipment (Fernando, 2005; Khorshidi, 2015). Herbaceous and agricultural waste has an ash content ranging between 4.5-10 wt% with high concentration of SiO_2 and alkali metal oxides. Aquatic waste in the form of marine micro-algae can be used for electricity production through fuel cells or CH_4 production, but both technologies are currently in early developmental stages (Bracmort, 2012; Khorshidi, 2015). Aquatic waste also has a high ash composition of over 20% with the ash being rich in SO_3 (Pour, 2018).

Current concerns also exist about the lack of emissions control if unsorted waste is incinerated, with the presence of trace elements including Si, Al, K, Mg, Ca and Na resulting in heavy metal salt production in the fly ash. Additional measures including thermal stabilisation of waste and electrostatic precipitation to filter dust and heavy metals are needed (Pour, Webley and Cook, 2018b). This is why

DCOW is a good choice for initial deployment of BECCS in NSW. As highlighted in Section 3.2 of this report, electrostatic precipitators (ESPs) would be required to meet NSW emission standards for Type 1+2 trace elements when co-firing DCOW with coal, but these already exist on NSW coal-fired power plants.

There is also concern about increased maintenance costs due to issues regarding boiler corrosion where waste is non-homogenous in nature and comprises of large proportions of high moisture and non-organic waste (Pour, Webley and Cook, 2018b). For these reasons, and since power plants may not have installed equipment that can deal with these issues, parallel co-combustion is considered for this scoping study (as per Sections 2 and 4). Therefore, only the costs associated with biomass handling, preparation and combustion, are included in the cost calculations presented in this Section. Additional operator costs incurred due to the introduction of co-firing, such as additional ESPs and maintenance, are hence not included.

5.1.2 Renewable Penetration

In 2018-19, 17% of electricity generation in NSW (or 12,749 GWh) was by renewable sources (Department of Industry, Science, Energy and Resources, 2020), continuing a steady increase of renewable energy penetration from a 9% share of generation at the beginning of the decade. The Climate Change Fund Strategic Plan implemented by the NSW Government aims to increase renewable energy capacity to 10,000 MW by 2022 (Clean Energy Council, 2019). In addition to the plan, the NSW Transmissions Infrastructure Strategy aims to increase NSW's interconnection with other states in the NEM while increasing the renewable energy capacity through Renewable Energy Zones (REZ) in NSW (NSW Department of Planning and Envrionment, 2018). REZs are areas of high energy resource potential for projects where transmission infrastructure upgrades are strategically built to connect such projects to the NEM instead of needing to build new projects alongside existing networks. In addition to the Transmission Infrastructure Strategy, the NSW Government's Electricity Strategy laid out a plan to deliver 3 new Renewable Energy Zone (REZ) in NSW's Central-West, New England and South-West regions. However, with over 90% of investment in new generation capacity in the NEM from 2012-2017 being in solar and wind which are variable in nature, there is a need to complement such with firm and flexible generation means (NSW Department of Planning and Envrionment, 2019). It is expected under AEMO's Draft 2020 NEM Integrated System Plan (ISP), that under such REZs, 5 to 21 GW of flexible, utility-scale dispatchable sources of energy will be needed. The ISP proposes flexible gas generators as a possible source (Australian Energy Market Operator, 2020).

5.1.3 Flexible Capture

Moving away from its traditional expected role as a source of steady state base-load generation, BECCS also has the potential to act as a flexible power source to fit in with increasing levels of intermittent renewable generation (Wiley, Ho and Donde, 2011; Mac Dowell and Staffell, 2016). As such, the role of BECCS will be to ramp up during levels of demand while ramping down during periods of renewable power output 'flooding' and periods of low electricity pricing (Mac Dowell and Staffell, 2016). This mode of CCS operation has been regarded from a system perspective as a low cost option to make CCS a competitive option as zero-emission electricity systems are pursued (Davison, 2011).

Possible flexible capture configurations include partial CO_2 capture (<85% capture) on a regular basis, part-time capture with the remainder of the flue gas emitted during off periods and variable capture where the plant operates at different capture rates during selected periods (Wiley, Ho and Donde, 2011). A study of these configuration in the context of coal fire power plants in the existing generation capacity of NSW revealed variable capture (in a combination of 90/40/20% capture) as the least cost option at \$100/tCO_2 avoided while achieving 50% average capture (Wiley, Ho and Donde, 2011). Additional studies looking at various generation mixes and electricity demand profiles as driven by policy to determine optimal plant upgrade options and dispatch cycles are proposed for this context, similar to a study done in the context of the European energy market (McCoy *et al.*, 2013). That study revealed that as renewable penetration increased, the residual load curve became steeper, hence requiring rapid and short term flexibility which was best met by open cycle gas turbine and only required a small proportion of CCS systems to be equipped with flexible capture (McCoy *et al.*, 2013).

Some of the technical challenges faced in flexible capture include effects on individual unit capacity factors, behaviour of the boiler temperature profile, capture unit performance and transient CO_2 supply to the transport network (Mac Dowell and Staffell, 2016). For the capture unit to be compatible with intermittent power sources, temporary storage of CO_2 rich solvent in tanks has been proposed in order to reduce the energy penalty of capture by saving steam extraction and CO_2 compression power (Domenichini *et al.*, 2013). As it is expected that the plant is not to be used at base load, there is no need to oversize the unit to cope with high demand periods. Additional strategies including part time capture and emission of flue gas during low demand periods, bypassing capture all together. In order to address transient CO_2 supply to transport networks, either CO_2 buffer storage (in tanks or via pipeline packing) or CO_2 rich solvent storage in tanks is proposed (Domenichini *et al.*, 2013). This would require reduction of pipeline size and hence reduce the plant's ability to maintain a high load factor (Domenichini *et al.*, 2013).

5.2 Task 4.3: Techno-economic performance predictions for a range of relevant case studies.

5.2.1 Technical Analysis

Methodology

The relevant case studies outlined in Section 2 (Figure 2-9) were run through the ICCSEM tool utilising the methodology outlined in Section 4.1. The case studies are summarised in Table 5-1.

Table 5-1: List of relevant case studies for techno-economic analysis

	Locations	Co-firing level
Single Pipeline Cases	1. Mt Piper 2. Bayswater 3. Eraring	a. 0% b. 10%
Network Cases	4. Eraring/Bayswater/Mt Piper – Dunedoo – Darling Basin	a. 0% b. 5%

The emissions output and fuel input were linearly scaled up from the base plant at 500 MW (used in Section 4.1) to the 660 MW (Bayswater), 700 MW (Mt Piper) and 720 MW (Eraring) plants. The mass flowrates of coal and DCOW (wood and paper) and emissions output for each co-firing scenario are shown in Table 5-2.

Table 5-2: Fuel consumption rates for co-firing scenarios

Parameter	Unit	Scenario								
Power Plant		660 MW – Bayswater			700 MW – Mt Piper			720 MW – Eraring		
Co-Firing Ratio	%	0	5	10	0	5	10	0	5	10
Fuel Consumption Rate										
Coal	t/h	277.31	271.25	263.19	294.12	287.69	279.15	302.52	295.91	287.12
Wood		-	7.14	14.6	-	7.57	15.51	-	7.79	15.95
Paper		-	7.14	14.6	-	7.57	15.51	-	7.79	15.95
Emissions Output										
Total Flue Gas	kg/s	774.88	790.77	802.69	821.84	838.70	851.34	845.32	862.66	875.66
CO_2 Flowrate		160.15	163.77	166.58	169.86	173.70	176.69	174.71	178.66	181.73

<u>Case Specific Assumptions</u>:

Single pipeline cases involve a CO_2 transport pipeline running directly from the power plant to the storage site. For the base case, an average distance of 858 km from plant to storage site was used based on road distances from Mt Piper, Bayswater and Eraring to the Darling Basin storage site. The estimated distances from each plant are shown in Table 5-3. It is also assumed that additional BECCS equipment is parasitic in nature.

Table 5-3: Distance from power plant to storage site for single pipeline cases

	Mt Piper	Bayswater	Eraring
Distance (km)	790	840	950

Network cases at 0% and 5% co-firing, involve a pipeline running from Eraring to Bayswater and further to a connection point at Dunedoo where the pipeline from Mt Piper connects. Distances are estimated from road distances. The collective emissions from all plants are then injected at the storage site. The distances for each section are shown in Table 5-4. It is assumed that additional power required for BECCS is obtained from the network and hence CCS is parasitic in nature.

Table 5-4: Distance from power plant to storage site for single pipeline cases

	Eraring - Bayswater	Bayswater - Dunedoo	Mt Piper - Dunedoo	Dunedoo -Darling Basin
Distance (km)	126	207	195	645

Maps showing each of these configurations can be seen in Section 2 in Figure 2-10 and Figure 2-11.

Results

Energy Requirements

The energy requirements for biomass pulverisation, carbon capture, transport and storage for each of the co-firing cases is shown in Table 5-5 with a graphical breakdown shown in Figure 5-1.

Table 5-5: Energy requirements for single pipeline and network BECCS cases at various co-firing levels

	Unit	Mt Piper		Bayswater		Eraring		Network	
		0%	10%	0%	10%	0%	10%	0%	5%
Biomass Pulveriser	MW	-	4.65	-	4.39	-	4.79	-	6.75
		Capture							
Solvent Regeneration	MW	111.85	116.32	105.46	109.67	115.04	119.65	332.35	339.86
Solvent Capture		5.89	6.13	5.56	5.78	6.06	6.31	17.52	17.91
Separation Compression		20.80	21.59	19.61	20.35	21.40	22.21	61.81	63.14
NOx Removal		11.45	11.88	10.80	11.20	11.78	12.21	34.03	34.74
SOx Removal		6.31	6.54	5.95	6.17	6.49	6.73	18.74	19.13
		Transport							
Initial Transport Compression	MW	49.39	50.81	46.41	48.49	50.28	52.93	149.98	153.96
Boosters		8.95	6.22	8.07	8.94	7.43	13.75	30.76	31.66
Injection		1.13	1.22	1.02	1.09	1.20	1.29	10.09	10.28
Total Power Requirement		215.8	225.4	202.9	216.1	219.7	239.9	655.30	678.68
Initial Power Sent Out		700.0	700.0	660.0	660.0	720.0	720.0	2080.0	2080.0
Power Sent Out after Retrofit		484.2	474.6	457.1	443.9	500.3	480.1	1424.7	1401.32
Energy Penalty	%	30.8	32.2	30.7	32.7	30.5	33.3	31.5	32.6

The largest contributor to the energy penalty is the capture unit, with solvent regeneration specifically requiring the most energy. The energy penalty for all cases ranges between 30–34% with a 2% average increase in energy penalty from the 0%–10% co-firing cases. Without co-firing, all power plants have roughly the same energy penalty, with Eraring being slightly lower as it has the largest unit size. With co-firing, energy penalty is larger due to there being more CO_2 generated, and there is also a marked increase in energy penalty as the distance to the storage size increases, with Mt Piper having the lowest energy penalty due to it being the closest to the injection site.

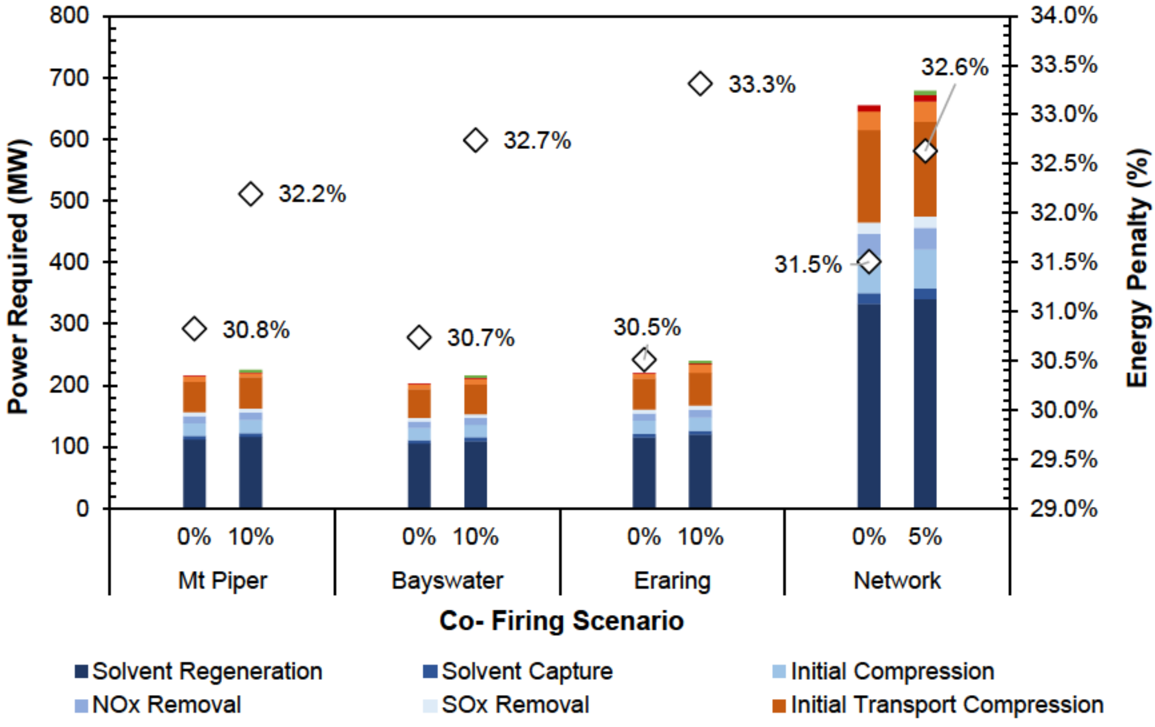

Figure 5-1: Energy requirement breakdown for single pipeline and network BECCS cases at various co-firing levels

The network cases have an energy penalty ranging between 31% and 33%, suggesting similar extra power requirements in proportion to energy sent out as the single pipeline cases. This is despite the expected economies of scale in transport; that is to say, the energy penalty should decrease as flow rate increases. The energy requirement for CO_2 transport changed from 13.95-15.03 W/t_{CO2} (transported)/yr in the single pipeline cases to 14.84-14.94 W/t_{CO2}/yr for the network cases, representing a maximum 1.3% decrease in energy requirements per tonne of CO_2 injected between the pipeline and network cases.

Nonetheless, the similar energy penalties may be explained by the additional power required for injection due to larger flowrates in the network cases which thereby offsets the decrease in energy requirements attributed to transport. The power requirement for CO_2 injection from all three sources is superlinear in nature, that is, there are diseconomies of scale. This is because a larger CO_2 injection flow rate requires more injection wells and, hence, there is well interference leading to a larger energy requirement to inject smaller flows of CO_2 per well. The power requirement for injecting CO_2 increased from 0.26-0.29 W/t_{CO2}/yr in the single pipeline cases to 0.83-8.5 W/t_{CO2}/yr for the network cases, representing a maximum 214% increase in energy requirements per tonne of CO_2 injected between the pipeline and network cases.

Emissions Intensity

The net emissions intensity for the single pipeline and network co-firing scenarios is shown in Table 5-6 and graphically in Figure 5-2.

Table 5-6: Net Emissions intensity for single pipeline and networks cases at varying co-firing levels

Cases	Locations	Co-firing level	Net Emissions Intensity (tCO_2/MWh)	
			No-CCS	CCS
Single Pipeline	Mt Piper	0%	0.87	0.13
		10%	0.83	0.02
	Bayswater	0%	0.87	0.13
		10%	0.83	0.02
	Eraring	0%	0.87	0.13
		10%	0.83	0.02
Network	Eraring/Bayswater/Mt Piper – Dunedoo – Darling Basin	0%	0.87	0.13
		5%	0.85	0.07

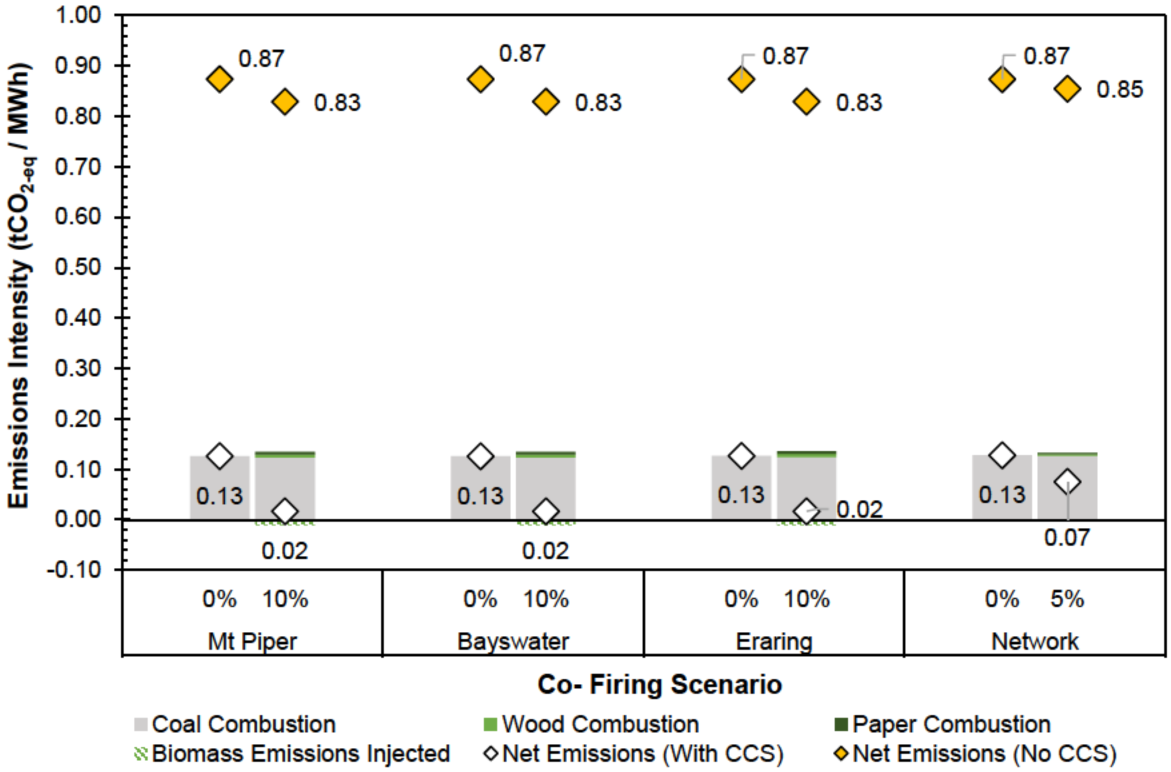

Figure 5-2: Emissions Intensity for all cases at varying co-firing levels

When CCS was applied to the base 0% co-firing single pipeline cases the emissions intensity decreased by 86%. As the co-firing ratio increased the net emissions intensity decreased by 87% from 0 to 10% co-firing to 0.02 tCO_2/MWh. When each of the co-firing locations were compared, similar emissions intensities were obtained for Bayswater and Mt Piper as they both have smaller units. However, the emissions intensity for Bayswater was 0.12% higher due to the longer transport distance for injection. The emissions intensity for the Eraring case increased by 0.57% due to it having a larger unit size of

720 MW. For the network cases, similar to the single pipeline cases, when CCS was applied to the 0% case, emissions intensity decreased by 86%. As the co-firing ratio increased from 0% to 5% co-firing, the net emissions intensity decreased by 41% to 0.07 tCO_2/MWh

5.2.2 Economic Analysis

Methodology

In order to assess the economic viability of the chosen BECCS cases, the Levelised Cost of Electricity (LCOE) and Cost of CO_2 Avoided were calculated. For the CCS cost component, costs were obtained from ICCSEM including CAPEX and OPEX elements. Further assumptions regarding biomass pulverisation and power plant refurbishment for BECCS are outlined in Table 5-7.

Table 5-7: Cost assumptions for BECCS cases

Component	Value	Units	Reference
Co-firing Boiler CAPEX	138	AU/kW_{th}$	(Basu, Butler and Leon, 2011)
Co-Firing Boiler Variable OPEX	5.52	AU/ kW_{th}$	
Co-Firing Boiler Fixed OPEX	5.52	AU/ MWh_{th}$	
Biomass Pulveriser CAPEX		$AUD	(Towler and Sinnott, 2013)
Equipment Cost (S)	$S = LF \times CEPCI \times CR(16{,}000 + 730S^{0.5})$		
Installed Equipment Cost (ISBL)	2.63(S)		
Offsite Costs (OSBL)	0.32(ISBL)		
Design, Engineering, Contingency Costs (DE)	0.33(ISBL+S)		
Biomass Pulveriser OPEX	5% (S)+2% (S+ISBL+ DE)		
Australia Location Factor (LF)	1.19	-	ICCSEM
CEPCI 2017	567.5	-	ICCSEM
USD to AUD Conversion Rate (CR)	0.77	-	ICCSEM
Power Plant Variable OPEX	4.28	$AU/MWh	(AEMO, 2018)
Power Plant Fixed OPEX	54.05	$AU/kW	
Coal Fuel Cost	2.77	$AU/GJ	
Biomass Transport Cost	0.11	AU/t_{waste}$/km	(National Academies of Sciences, Engineering, 2019)
LCOE Assumptions			
Discount rate (r)	6.4	%	ICCSEM
Project Life/Injection time for CCS (n)	30	years	ICCSEM
Capital Expenditure Spend Timeline	Year -1 = 40% Year 0 = 60%		
Cost of CO_2 Avoided Assumptions			
Average Emissions Intensity (Mt Piper, Eraring, Bayswater)	0.873	tCO_2/MWh	(Clean Energy Regulator, 2019)

Biomass Transport: The cost of biomass transportation was calculated at a rate of \$0.11/ t_{waste}/km based on US transport rates for wood biomass (National Academies of Sciences, Engineering, 2019), to which an Australian location factor and cost conversion was applied. It was assumed that the Greater Metropole Sydney Landfill Cluster serviced all plants. While another landfill cluster in the Newcastle area was identified in Figure 2-8, as stated in Section 2.2.3, it only holds 8% of all landfilled waste in NSW, with the Greater Sydney Cluster holding the highest proportion of landfilled waste in NSW at 68%. The distance from each of the plants to the midpoint of the cluster was used, resulting in a distance of 130 km for Mt Piper, 140 km for Eraring and 250 km for Bayswater. The key highway networks were identified and optimised as shown in Figure 2-8.

Levelised Cost of Electricity (LCOE) (\$/MWh Sent Out): The levelised cost of electricity measures the breakeven capital and operating cost per unit of electricity sent out over the project lifetime. This metric allows for consideration of all costs incurred and the long-term value of the scenario. The LCOE was calculated using the following equations utilising inputs from Table 5-7:

$$LCOE\ (\$/MWh) = \frac{CAPEX_{annualised} + OPEX_{annual} + Fuel\ Cost_{annual}}{G_O} \tag{5-1}$$

where G_0 is the annual electricity generation. The CAPEX is amortised over the project life using the following formulas:

$$CAPEX_{annualised} = \frac{CAPEX_{NPV}}{Annuity\ Factor} \tag{5-2}$$

$$Annuity\ Factor = \frac{1}{r(1+r)^{n_i-1}} - \frac{1}{r(1+r)^{n_f}} \tag{5-3}$$

where r is the real discount rate, n_i is the initial year of operation (counting from year 1 as the year construction of the capture plant and/or refurbishment commences) and n_f is the final year of operation.

Cost of CO_2 Avoided (COA) (\$/tCO_2): The cost of CO_2 avoided measures the cost of the BECCS process as a function of CO_2 captured. This was calculated using the following equation utilising inputs from Table 5-7 and net emissions utilised as specified in Table 5-6:

$$COA = \frac{LCOE_{BECCS} - LCOE_{no-BECCS}}{EI_{(no-BECCS)} - EI_{(BECCS)}} \tag{5-4}$$

Results

The LCOE and COA for all the single pipeline and network cases are shown in Table 5-8 and shown graphically in Figure 5-3.

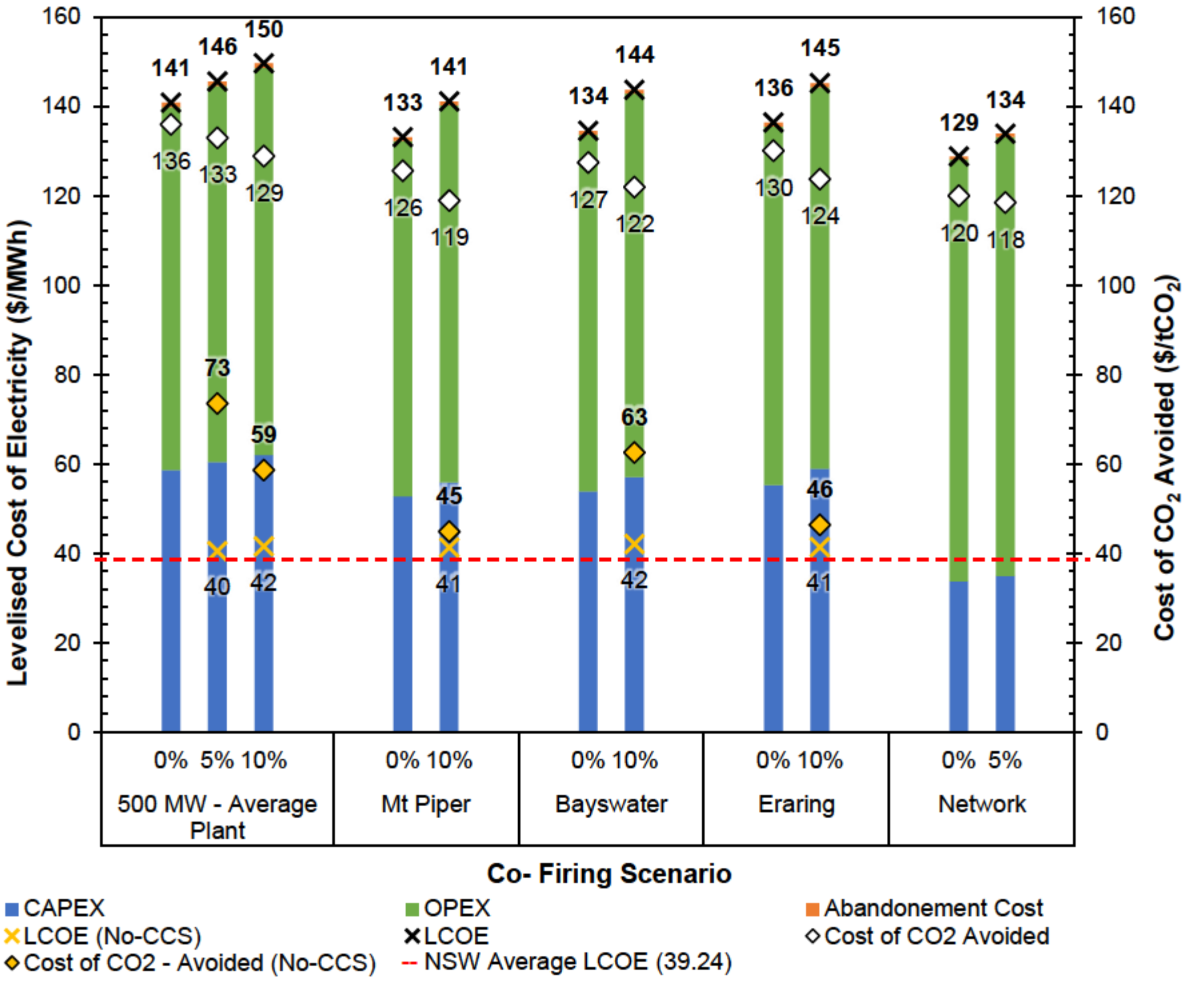

Figure 5-3: Levelised Cost of Electricity and Cost of CO_2 Avoided for all cases

Table 5-8: Levelised Cost of Electricity and Cost of CO_2 Avoided for all cases

Cases	Locations	Co-firing level	LCOE($/MWh) No-CCS	LCOE($/MWh) CCS	COA ($/tCO$_2$) No-CCS	COA ($/tCO$_2$) CCS
Single Pipeline	500 MW – Average Plant	0%	39.2	140.8	-	136.0
		5%	40.4	145.5	73.5	133.0
		10%	41.5	149.6	58.6	128.9
	Mt Piper	0%	39.2	133.1	-	125.5
		10%	41.2	141.1	44.9	118.9
	Bayswater	0%	39.2	134.5	-	127.4
		10%	42.0	143.7	62.5	121.9
	Eraring	0%	39.2	136.4	-	130.1
		10%	41.3	145.2	46.3	123.7
Network	Eraring/ Bayswater/Mt Piper – Dunedoo – Darling Basin	0%	-	128.8	-	120.0
		5%	-	133.8	-	118.4

As shown in the 500 MW power plant cases in Figure 5-3, the LCOE increases with co-firing level. This is primarily attributable to the increase in CAPEX for each of the cases, with OPEX remaining within the range of $213-216 million for both co-firing levels. The increase in CAPEX is attributed to increased boiler size requirements and subsequent increase in CO_2 volume for injection. The LCOE for the no-CCS cases ranges between \$40.4/MWh-\$41.5/MWh denoting CCS as the largest cost contributor to the BECCS system. The COA decreases with co-firing level, attributable to the decrease in net emissions at a rate of 46% from 0% to 5% co-firing and 71% for 5% to 10% co-firing as compared to the increase in LCOE by 3.3% from 0% to 5% co-firing and 2.8% for 5% to 10% co-firing for the CCS cases.

The lowest observable LCOE for the single pipeline co-firing cases was Mt Piper at \$141.1/MWh for CCS and \$41.2/MWh for no-CCS attributable to it having the lowest unit size at 660 MW and injection distance at 790 km across all plants. This case also produced the lowest COA at \$118.9/tCO_2 across the single pipeline CCS cases with the lowest COA overall reported by the 5% network case at \$118.4t/CO_2.

The network case at 5% co-firing resulted in an LCOE of \$133.8/MWh, 5% lower than the Mt Piper 10% case. This is also the lowest LCOE for all of the BECCS co-firing cases. This is due to the optimisation and economies of scale of the transport network, with the network cases reporting significantly lower CAPEX contributions to the LCOE as compared to the single pipeline cases. The lowest LCOE overall for the CCS cases was observed in the 0% co-firing network case at \$128.8/MWh.

<u>Sensitivity to Biomass Transport Cost</u>

A key cost considered in relation to biomass was the cost of biomass transport. For each of the cases, biomass transport costs represented 0.4-2% of the total LCOE of the BECCS system. The lowest transport cost was for the Mt Piper 5% co-firing single pipeline case due to shortest distance to landfill at 130 km.

The highest transport cost was at Bayswater, owing to its 250 km distance to landfill. As mentioned in the methodology in Section 2, while the Newcastle landfill cluster is closer in proximity to Bayswater, it is unable to service the biomass requirements for Bayswater. An alternate case splitting biomass sources between the Greater Sydney and Newcastle for Baywater in the single pipeline and network cases was considered. For the single pipeline Bayswater 10% co-firing case, 23% of its biomass supply was provided by the Newcastle cluster resulting in transport cost decreasing by 14%, while decreasing the LCOE by 0.2% to \$143.4/MWh. For the 5% co-firing network case, 15% of biomass was provided by the Newcastle cluster with the transport cost decreasing by 18% while the LCOE decreased by 0.1% to \$133.7/MWh.

6 Conclusions and Recommendations

This project assessed the technical and economic viability of reducing emissions from a representative conventional coal power plant within NSW through co-combustion with DCOW from MSW and C&I waste, coupled with the negative emissions gained through implementation of CCS.

Areas of investigation included identifying potential networks for BECCS (Milestone 1), understanding the effects of co-combustion on the combustion cycle and exhaust gas (Milestone 2), assessing the GHG reduction potential through an LCA (Milestone 3) and evaluating the economic viability of BECCS in NSW (Milestone 4).

Milestone 1: Identifying potential networks for BECCS in NSW through mapping of existing and proposed MSW sources, coal power plants and geological storage sites in NSW.

A survey of MSW sources in NSW revealed the largest waste cluster to be that of Greater Metropolitan Sydney, producing 68% of waste in NSW. Wood and paper were considered as eligible biomass feedstock for all the case studies due to waste availability, common usage in other BECCS studies and modelling capabilities. Construction and Industrial sources of wood were selected over MSW sources due to higher rates of availability, attributed to higher rates of recycling and sorting in the industry. The total amount of eligible waste available for BECCS was approximately 830,000 tonnes/year.

All the coal-fired power plants in NSW contain pulverised coal boilers and were potentially suited to either direct co-combustion or parallel co-combustion. Considering plant age, the power plants that were deemed suitable included Mt Piper at an age of 27 years, Eraring at an age of 37 years and Bayswater at an age of 35 years. Rather than opting for direct co-combustion which requires significant refurbishment of the boiler, a parallel co-combustion configuration was considered.

Single plant-pipeline cases were selected to be examined at 0% and 10% co-firing levels, as well as a network case at 0% and 5% co-firing levels due to waste availability constraints. The network case joined the power plants to a connection point at Dunedoo, directing all CO_2 captured from the plants to an injection site (Mena Murtee-1) in the Pondie Range Trough, Darling Basin.

Milestone 2: Understanding the effects of co-combustion of waste on the combustion cycle and exhaust gas of a coal power plant in NSW, including at different ratios.

The effect of 5% and 10% co-firing on the combustion cycle and exhaust gas was investigated via a combustion and trace element model developed by researchers from Imperial College London. The model assumed each fuel entered separately into a plug-flow reactor and produced its own flue gas which was subsequently combined. The combined flue gas pressure for both cases was set at 1 atm.

Due to the inlet gas flow rate adjustment, temperature and gas compositions leaving both columns had relatively similar molar percentage, namely 14% for CO_2, 7% for H_2O, 4% for O_2, and 75% for N_2.

The DCOW share in coal co-combustion affected concentrations of the emitted trace elements. However, higher DCOW share did not necessarily result in more emitted trace elements. It was observed that the emitted trace element concentrations were lower for 5% DCOW co-combustion possibly due to DCOW having significantly lower trace element concentrations than coal.

For a lower share of coal (that is higher rates of co-firing DCOW), more ash-forming elements were released, except for silica, due to the contribution of the waste wood. Trace elements were mostly emitted more from the higher share of coal than from the lower one. However, some elements, such as Pb, Cd, and As, show an increase in emissions as the share of coal is decreased. This indicates that the emission concentrations depend on the initial concentrations. Further, the modelled concentrations of type 1 and 2 emissions aggregated were significantly higher than NSW limits, with Mn and V emissions being the largest contributors. This indicated that an aerosol precipitator is required to capture aerosols formed prior entering emission stack.

The parallel entrained-flow combustion model was capable of predicting the emitted trace element concentrations. However, the evaluation comprehensiveness of this model was limited with respect to trace element interaction within the particle. Future analysis on less extreme conditions, e.g. a fluidised-bed boiler or under conditions typical of a NSW coal-fired boiler, may be required to observe elemental interactions in the bed.

Milestone 3: Assessing the greenhouse gas and carbon dioxide reduction potential of BECCS deployment with DCOW through a life cycle assessment, as well as ascertaining the opportunities for negative emissions.

A life cycle assessment of a hypothetical 500 MW power plant in NSW was modelled using a 'cradle-to-grave' scope to account for emissions at all stages of the process. As the co-firing ratio increased, life cycle CO_2 emissions decreased. BECCS co-firing at 10% reduced life cycle CO_2 emissions by 81% from 938 to 181 kg CO_2/MWh.

Of the six scenarios considered, Scenario 6 (10% co-firing with CCS) has the lowest life cycle GWP of 181 kg CO_2 / MWh. Compared with the current emissions intensity of 938 kg CO_2 / MWh (Scenario 1) this represents a decrease in GWP of 81%. Without CCS, co-firing has modest benefits, with life cycle emissions decreasing by 3% when increasing co-firing from 0% to 10% (Scenario 1 vs 3). In each scenario, direct emissions from combustion at the power plant was the largest contributor to GWP, followed by emissions attributed to coal procurement, and then emissions from the electricity generation for pipeline boosters and tophole compression. In Scenarios 4 (5% co-firing with CCS) and 6, emissions from pipeline operation were accounted for. The electricity for pipeline generation is assumed to come from the NSW grid, of which the majority is coal-fired power. Powering pipeline compressors with solar power is a suggested area of research, particularly given the abundance of space in regional areas through which the pipelines run.

At current plant HHV efficiencies, and at the baseline CCS energy penalty, the minimum co-firing ratio needed to achieve negative emissions was found to be 29.8%. The smallest power plant of the three power plants used as the basis for the analysis is Mt Piper. The maximum co-firing ratio achievable for a plant of this scale was 10.5% due to DCOW availability, which is 19.3% short of the negative emissions target.

Milestone 4: Evaluating the economic viability of BECCS in NSW; including the impact on the levelised cost of electricity ($/MWh$_e$). This analysis will incorporate sensitivity analysis to understand the effects of waste and transport costs on the feasibility of the CCS.

A techno-economic assessment of all the cases was carried out using data obtained primarily from the Integrated Carbon Capture and Storage Economics Model (ICCSEM). The energy penalty for the BECCS systems ranged between 30-34% of total energy sent out, with the energy penalty increasing with co-firing ratio. When CCS was applied to the 0% co-firing cases, the emissions intensity of the cases decreased by 86% from 0.87 tCO_2/MWh to 0.13 tCO_2/MWh. For the single pipeline cases, an increase in co-firing ratio to 10% co-firing reduced the net emissions intensity of the cases to 0.02 tCO_2/MWh. For the network cases, the co-firing ratio increased from 0% to 5% co-firing, the net emissions intensity decreased by 41% to 0.07 tCO_2/MWh.

In general, increasing the co-firing level increases the LCOE and decreases the COA. The LCOE of all the BECCS cases ranged between $128-150/MWh with the COA ranging between $119-136/$tCO_2$ avoided. The lowest LCOE at $133.3/MWh was reported at the Mt Piper 0% co-firing case, due to this case having the shortest transport distance across all cases, at 790 km. For the single pipeline co-firing cases, the Mt Piper BECCS case at 10% co-firing reported that lowest LCOE at $141.1/MWh and lowest COA at $118.9/$tCO_2$ avoided. Overall, however, the lowest COA was reported by the 5% Network case at $118.9/$tCO_2$ avoided with its LCOE standing at $133.8/MWh, the lowest of all co-firing cases. As this scoping study assumed the commercially available MEA solvent, lower costs (both in terms of LCOE and COA) as well as lower energy penalties may be achievable with improved solvent capture technologies.

It was assumed that the Greater Metropole Sydney landfill cluster serviced all the power plants. A sensitivity analysis was carried out in relation to the Bayswater power plant which was located at the greatest proximity to the selected landfill cluster. When biomass was sourced from the Newcastle cluster (to the extent it was available), transport costs decreased by 14% for the single pipeline case and by 18% for the network case. The LCOE however decreased by 0.1-0.2%.

Recommendations

The investigations reported in this study provide strong evidence that BECCS can significantly reduce CO_2 emissions. Further research considering additional sources of biomass in NSW to supplement wood waste and further technical study into the effects of MSW on the co-firing system may unlock greater opportunities to integrate BECCS in the NSW electricity generation pool. This should include consideration of other LGA clusters, as well as more detailed modelling and analysis of other combustible MSW fractions (such as textiles and dry garden/food waste) or other combustible wastes (such as agricultural waste and medical waste) that were not included in this study. Additionally, detailed life cycle assessments of the proposed single pipeline and network cases (including the use of ash suitable for concrete production and recycling of pipeline steel), as well as detailed sensitivity analyses to larger range of techno-economic factors such as the cost of capital, storage site and access to waste are recommended to more accurately assess if BECCS should form part of future policy to meet emissions reduction targets. Greater consideration of the impact of a circular economy and available end of life combustibles are also recommended.

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8 Appendices

8.1 Publications arising from the Project

Submitted Conference Abstract

J.S. Jones, G.A. Fimbres Weihs, M. Ho, P.S. Fennell, W. Meka, D.E. Wiley, "Delivering negative emissions with BECCS – A Life Cycle Assessment of coal-waste co-firing with CO_2 transport and storage", 15th International Conference on Greenhouse Gas Control Technologies GHGT-15, 5th - 8th October 2020, Abu Dhabi, UAE.

Journal Paper – in preparation

J.S. Jones, G.A. Fimbres Weihs, M. Ho, A. Abbas, P.S. Fennell, W. Meka, D.E. Wiley, "Negative Life Cycle emissions through coal-waste co-firing with CO_2 transport and storage in NSW" (*in preparation*)

Undergraduate Honours Thesis

J.S. Jones (2019), "A Life Cycle Assessment of Bio-Energy with Carbon Capture and Storage (BECCS) in NSW", Bachelor of Chemical and Biomolecular Engineering (Honours) and Commerce, The University of Sydney.

8.2 Staff engaged on the Project and associated qualifications obtained

Institution	Staff	Qualification obtained
The University of Sydney, School of Chemical and Biomolecular Engineering	Joseph Jones	Bachelor of Chemical and Biomolecular Engineering (Honours) and Commerce
	Rameen Hayat Malik	
	Jake Zhai	
	Dr Gustavo Fimbres Weihs	
	Dr Minh Ho	
	Prof Dianne Wiley	
	A/Prof Ali Abbas	
Imperial College, London	Prof Paul Fennell	
	Wahyu Meka	

8.3 Additional Data

<u>Life Cycle Assessment Data: Base Case Scenarios</u>

The life cycle assessment data for each of the three base case scenarios is provided in the tables in this appendix

Scenario	0% - with CCS	5% - with CCS	10% - with CCS	0% - No CCS	5% - No CCS	10% - No CCS
General Parameters						
Plant Capacity (MW)	500	500	500	500	500	500
MWs/MWh	3600	3600	3600	3600	3600	3600
Fuel Consumption - Unadjusted for CCS (kg/h)						
Coal Mass Consumption	210084	205491	199389	210084	205491	199389
Wood Mass Consumption	0	5408	11077	0	5408	11077
Paper Mass Consumption	0	5408	11077	0	5408	11077
Mass Fraction of Flue Gas (%) - Mass flow compositions						
CO_2	20.67%	20.71%	20.75%	20.67%	20.71%	20.75%
H_2O	4.07%	4.19%	4.30%	4.07%	4.19%	4.30%
O_2	4.21%	4.20%	4.19%	4.21%	4.20%	4.19%
N_2	71.06%	70.91%	70.75%	71.06%	70.91%	70.75%
Flue Gas Mass Flow (kg/s)						
Total Flue Mass Flow Rate	587.03	599.07	608.10	587.03	599.07	608.10
CO_2 Mass Flow	121.33	124.07	126.20	121.33	124.07	126.20
H_2O Mass Flow	23.88	25.07	26.18	23.88	25.07	26.18
O_2 Mass Flow	24.69	25.15	25.47	24.69	25.15	25.47
N_2 Mass Flow	417.13	424.78	430.25	417.13	424.78	430.25
Total Flue Mass Flow (kg / MWh) - For mass flows per functional unit						
CO_2 Mass Flow	873.567	893.297	908.632	873.567	893.297	908.632
H_2O Mass Flow	171.940	180.519	188.461	171.940	180.519	188.461
O_2 Mass Flow	177.798	181.064	183.399	177.798	181.064	183.399

Scenario	0% - with CCS	5% - with CCS	10% - with CCS	0% - No CCS	5% - No CCS	10% - No CCS
N_2 Mass Flow	3003.319	3058.431	3097.821	3003.319	3058.431	3097.821
Fuel Mass Consumption - Not Normalised for Energy Penalty (kg/s)						
Coal	58.357	57.081	55.386	58.357	57.081	55.386
Wood	0.000	1.502	3.077	0.000	1.502	3.077
Paper	0.000	1.502	3.077	0.000	1.502	3.077
Fuel Mass Consumption - Not Normalised for Energy Penalty (kg/MWh)						
Coal	420.168	410.982	398.778	420.168	410.982	398.778
Wood	0.000	10.815	22.154	0.000	10.815	22.154
Paper	0.000	10.815	22.154	0.000	10.815	22.154
CCS Parasitic Energy Required (MWh per tonne CO_2)						
CCS Energy - Absorption	0.21824	0.21824	0.21824	0.000	0.000	0.000
CCS Energy - Compression	0.12352	0.12352	0.12352	0.000	0.000	0.000
Co-firing - Preparation Data (MJ / MWh)						
Wood - Hog Pulveriser	0.000	1.730	3.545	0.000	1.730	3.545
Paper - Hog Pulveriser	0.000	1.730	3.545	0.000	1.730	3.545
Wood - Fine Pulveriser	0.000	0.379	0.775	0.000	0.379	0.775
Paper - Fine Pulveriser	0.000	0.379	0.775	0.000	0.379	0.775
Total energy demand for pulverising	0.000	4.218	8.640	0.000	4.218	8.640
Total proportional energy demand	0.000	0.001	0.002	0.000	0.001	0.002
Final Energy Losses						
Energy Loss (CCS) (MWh/t CO_2)	0.3418	0.3418	0.3418	0.000	0.000	0.000

Scenario	0% - with CCS	5% - with CCS	10% - with CCS	0% - No CCS	5% - No CCS	10% - No CCS
Energy Loss (CCS) (MWh/MWh) - Penalty %	0.2985	0.3053	0.3105	0.000	0.000	0.000
Energy Loss (Pulverising) (MWh/MWh)	0.0000	0.0012	0.0024	0.0000	0.0012	0.0024
New Energy (MWh)	0.7015	0.6935	0.6871	1.0000	0.9988	0.9976
Fuel Mass Consumption - Normalised for Energy Penalty (kg/MWh)						
Coal	598.997	592.587	580.405	420.168	411.464	399.738
Wood	0.000	15.594	32.245	0.000	10.828	22.208
Paper	0.000	15.594	32.245	0.000	10.828	22.208
Transportation Data - Wood and Paper to Power Plant						
Wood	0.000	2.703	5.589	0.000	1.877	3.849
Paper	0.000	2.703	5.589	0.000	1.877	3.849
Calculating Plant Efficiency - The electricity generated by the plant divided by the thermal energy (energy in the fuel) that was fed to the plant						
Coal Calorific Value In (MJ)	14256	14104	13814	10000	9793	9514
Wood Calorific Value In (MJ)	0	259	536	0	180	369
Paper Calorific Value In (MJ)	0	259	536	0	180	369
HHV Efficiency (%)	25.25%	24.62%	24.18%	36.00%	35.46%	35.12%
Material inputs and outputs to CCS						
IN: MEA consumption (kg/MWh)	3.34	3.37	3.41	0.00	0.00	0.00
IN: NaOH consumption (kg/MWh)	0.19	0.19	0.19	0.00	0.00	0.00
IN: Activated Carbon consumption (kg/MWh)	0.11	0.11	0.11	0.00	0.00	0.00
OUT: Ammonia emissions (kg/MWh)	0.30	0.30	0.31	0.00	0.00	0.00

Scenario	0% - with CCS	5% - with CCS	10% - with CCS	0% - No CCS	5% - No CCS	10% - No CCS
New CO_2 emissions from the reactor						
New CO_2 emissions (kg/MWh)	1245	1288	1322	874	894	911
New H_2O emissions (kg/MWh)	245	260	274	172	181	189
New O_2 emissions (kg/MWh)	253	261	267	178	181	184
New N_2 emissions (kg/MWh)	4282	4410	4509	3003	3062	3105
Total flue gas mass flow (kg/MWh)	6026	6219	6372	4227	4318	4389
Calculating air flow for the particulate matter emissions						
Air Flow Rate (kg of air per kg of fuel)	3.93	4.01	4.08	3.93	4.01	4.08
Total Air Flow (kg per MWh of electricity)	2354	2500	2632	1652	1736	1813
Emissions of Trace elements from the reactor (not to the environment) (g/MWh)						
Silicon - Si	23.05	22.95	22.66	16.17	15.94	15.60
Iron - Fe	4.12	4.11	4.07	2.89	2.86	2.80
Magnesium - Mg	1.03	0.99	0.93	0.72	0.69	0.64
Sulphur - S	0.58	0.58	0.57	0.41	0.40	0.39
Titanium - Ti	0.48	0.52	0.57	0.34	0.36	0.39
Calcium - Ca	0.39	0.45	0.51	0.28	0.31	0.35
Potassium - K	0.22	0.23	0.24	0.16	0.16	0.16
Sodium - Na	0.14	0.15	0.15	0.10	0.10	0.11
Aluminium - Al	0.07	0.08	0.09	0.05	0.06	0.06
Barium - Ba	0.04	0.04	0.04	0.03	0.03	0.03
Manganese - Mn	0.03	0.03	0.03	0.02	0.02	0.02
Phosphorus - P	0.02	0.02	0.03	0.01	0.02	0.02
Vanadium - V	0.01	0.01	0.01	0.01	0.01	0.01
Zinc - Zn	0.0063	0.0067	0.0072	0.0044	0.0047	0.0050

Scenario	0% - with CCS	5% - with CCS	10% - with CCS	0% - No CCS	5% - No CCS	10% - No CCS
Cobalt - Co	0.0058	0.0058	0.0058	0.0041	0.0040	0.0040
Chromium - Cr	0.0027	0.0029	0.0031	0.0019	0.0020	0.0021
Chlorine - Cl	0.0024	0.0032	0.0040	0.0017	0.0022	0.0028
Nickel - Ni	0.0019	0.0019	0.0019	0.0013	0.0013	0.0013
Copper - Cu	0.0009	0.0011	0.0012	0.0006	0.0007	0.0008
Lead - Pb	0.0005	0.0006	0.0008	0.0003	0.0004	0.0005
Arsenic - As	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002
Molybdenum - Mo	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Antimony - Sb	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000
Selenium - Se	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mercury - Hg	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cadmium - Cd	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Particulate Matter	22.02	22.27	22.48	15.44	15.46	15.48
SO_X and NO_X						
NO_X (kg/MWh)	2.71	2.70	2.67	1.90	1.88	1.84
SO_X (kg/MWh)	2.41	2.36	2.29	1.69	1.64	1.58
For CCS Cases - Removal Efficiency Adjustments - FGD						
NO_X emissions (kg/MWh)	2.71	2.70	2.67	1.90	1.88	1.84
SO_X emissions (kg/MWh)	0.24	0.24	0.23	1.69	1.64	1.58
Calculate the Amount of Ash sent to Landfill						
Bottom ash per tonne of coal	0.19	0.19	0.19	0.19	0.19	0.19
Coal Bottom Ash (kg/MWh)	115.60	114.36	112.01	81.09	79.41	77.14
Wood Bottom Ash (kg/MWh)	0.000	6.019	12.446	0.000	4.179	8.572

Sign Off

I, the undersigned, being a person duly authorised by the Grantee, certify that:

1. the above information is true and complete;

2. the expenditure of the Funding received to date has been used solely on the Project; and

3. there is no matter or circumstances of which I am aware that would constitute a breach by the Grantee or, if applicable the End Recipient and Subcontractors', of any term of the Funding Deed.

Signature: [REDACTION]	Signature: [REDACTION]
Position: Principal Investigator	Position: Director, Research Grants and Contracts
Name: Dianne Wiley	Name: Pearly Harumal
Date: 12th March 2020	Date: 13/03/2020