A synergistic approach to decarbonise the industrial sector with negative emission technologies

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Abstract

There is a need for a rapid and large scale decarbonisation to reduce CO_2 emissions by 45% within 12 years. Thus, we propose a method that accelerates decarbonisation across multiple sectors via a synergistic approach with bioenergy with CCS (BECCS), which is able to remove 740 kg_{CO_2} from air per MWh electricity generated. Industry is a hard-to-decarbonise sector which presents a unique set of challenges where, unlike the power sector, there are no obvious alternatives to CCS. One of these challenges is the significant variation of CO_2 concentration, which directly influences CO_2 capture costs,ranging from $\$10/t_{CO_2}$ to over $\$170/t_{CO_2}$ for high (95 – 99% CO_2) and low CO_2 concentration (4% CO_2) applications, respectively. Re-purposing the existing coal-fired power plant fleet into BECCS displaces CO_2 emissions from coal-use and enables a just transition, *i.e.*, avoiding job loss, providing a supportive economic framework that does not rely on government subsidies. Negative emissions generated from capturing and storing atmospheric CO_2 can be converted into negative emission credits (NECs) and auctioned

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to hard-to-decarbonise sectors, thus providing another revenue stream to the power plant. A levelised cost of electricity (LCOE) between \$70 and \$100 per MWh can be achieved through auctioning NECs at \$90 – \$135 per t_{CO_2}. Offsetting the global industrial CO_2 emissions of 9 Gt_{CO_2} would require 3000 BECCS plants under this framework. This approach could jumpstart industrial decarbonisation whilst giving this sector more time to develop new CCS technologies.

Keywords: Oxy-combustion, Carbon capture and storage, BECCS, Techno-economic analysis

1. Introduction

1.1. Climate change mitigation targets

The recent IPCC report on global warming of 1.5 °C stresses that the global decarbonisation effort is progressing at an insufficient rate.[1] Global GHG emissions require significant and rapid reductions across all sectors (e.g., energy, industry, agriculture, transport) to meet the 1.5 °C target, and prevent the adverse effects of climate change.[1] The report findings indicate that limiting global warming to 1.5 °C requires a net 45% reduction of global anthropogenic CO_2 emissions relative to 2010 levels by 2030, reaching net negative by 2050.[1] Thus, "negative emissions", *i.e.*, CO_2 removal from air, will be necessary to balance residual emissions.[2] To date, the majority of efforts to reduce CO_2 emissions have focused on phasing out fossil fuels from the power sector and their replacement with renewable energy.[3]

Other sectors such as industry, transport, land, and buildings do not have a renewable technology substitute that is commercially available.[4] Direct

decarbonisation of these "hard-to-reach" sectors at the required rate and scale remains a major challenge, *e.g.*, directly applying CO_2 capture and storage (CCS).[4, 5] Strategic deployment of negative emission technologies (NET) presents opportunities for cross sector reductions in CO_2 emissions at an accelerated rate.[6–8] Negative emissions can be defined as being a human intervention to remove CO_2 from the atmosphere, thus augmenting natural CO_2 sinks.[7] NETs that capture atmospheric CO_2 via photosynthesis include bioenergy with CCS (BECCS), afforestation/reforestation (AR), soil carbon sequestration, biochar, and ocean fertilisation.[6–9] Atmospheric CO_2 capture via chemical processes comprise direct air capture (DAC) and enhanced weather/ocean alkalination.[6–8]

Whilst all these approaches are viable options for removing atmospheric CO_2, BECCS has the advantage of simultaneously generating electricity.[7, 8] AR has the potential to remove 0.5 – 7 Gt_{CO_2}/yr in the period of 2050, similar to BECCS.[7, 8] However, AR requires more time and space to establish, with sequestration productivity expected to decline from 3.7 Gt_{CO_2} in 2065 to 0 Gt_{CO_2} in 2095, due to decreased rate of growth with increased plant age.[7, 8] Other challenges such as conserving the forests and protecting them from wildfires, as well as other forms of carbon leakage, require constant monitoring after AR has established, bringing additional costs to this activity.[7, 8]

The current total global CO_2 emissions across all sectors is 41 Gt_{CO_2} per year[1].[10, 11] This provides a sense of scale for global efforts towards miti-

[1]This value considers annual CO_2 emissions from industrial sector & fossil fuel use, accountable for 36 Gt_{CO_2}, and land use change, accountable for 5 Gt_{CO_2}.

gating climate change and reaching net zero emissions by 2050. Whilst other countries, such as the Netherlands are currently contemplating ambitious climate targets, the UK is one of the few countries in the world which has a legally binding target for 2050[2].[12] The original target for the UK was an 80% reduction in CO_2 emissions by 2050 relative to 1990 levels.[13] However, following the Paris agreement[14], the UK has re-examined their CO_2 emissions reduction targets, where the long-term focus will now be on achieving net zero CO_2 emissions by 2050 in addition to the previous target.[13, 15] In the UK context, the CCC has recently suggested that removing 45 – 50 Mt_{CO_2} from the atmosphere will be necessary to meet the mitigation targets associated with the 2008 Climate Change Act.[16]

For most countries, meeting climate change mitigation targets will require deep reductions in GHG emissions across all sectors.[17] Emission targets for the transportation sector can be achieved by substituting fossil fuels with hydrogen (H_2) or electric vehicles.[18] Although this strategy could theoretically be applied to the aviation sector, it raises concerns about safety during flights, making this an unlikely scenario for this sector.[19, 20] Hence, reducing emissions from this activity will most likely be achieved indirectly and thus require a strong policy framework to succeed, for example CORSIA[3] for

[2]Other countries with a legally binding climate change mitigation target include Sweden, Denmark, France, New Zealand, Costa Rica, Bhutan.

[3]Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) was proposed by the International Civil Aviation Organisation. This scheme defines a quota of carbon emissions to airlines via credits, which if exceeded then the airline must buy additional carbon credits.

international flights.

Whilst renewable energy production from solar panels and wind turbines provide an important contribution to the decarbonisation of the power sector, there is still the need to guarantee a firm power supply.[21–25] Furthermore, the costs associated with prematurely decommissioning power plants must also be met[26], which also raises questions regarding electricity prices[27] and loss of jobs.[28] Indeed, 38% of total electricity generated worldwide during 2017 comes from coal-fired power plants[29], which serves as foundation for the argument of jobs lost by transitioning to low or zero carbon energy sources. Patrizio et al. [30] demonstrates that reducing US coal emissions by transitioning to BECCS not only retains existing jobs, but also offers the opportunity of boosting employment through the creation of jobs in the operations, manufacturing, forestry and transport/logistics sectors. Whilst this study is focused on US, it is possible to assume that the same would be true if applied globally. There are a number of technology solutions that provide low carbon, dispatchable firm power, e.g., nuclear power, renewable energy combined with grid-scale energy storage, and CCS/BECCS.[23, 31] Some studies are beginning to quantify the societal value (e.g., growth in GDP or employment) of implementing these low carbon energy technologies.[32–36] Rather than looking at the benefit of single technologies, understanding the combined value of deploying multiple low carbon technologies is also important.[21, 23, 24]

The industrial sector, however, faces a unique set of problems due to the existence of a large source of CO_2 emissions from the production process.[3–5, 37] Industrial sectors such as steel and cement, vital in the construction

of modern infrastructure, must deeply curb their emissions to meet climate change mitigation targets.[38] Some processes may be decarbonised using different feedstocks and/or radically new processes, but may also raise concerns about product quality. Radically new processes may be difficult to commercialize and generally require substantial upfront investment. Key industries, such as iron and steel, or cement, currently have no renewable alternative to curb their CO_2 emissions and would consequently remain unsolved.[4] Thus, CCS currently stands as the only option for curbing industrial emissions.[4, 9, 38] However, applying CCS to the industrial sector is likely to be costly[9, 37] with concerns about product quality[9, 37] and technology *lock-in*[4] being significant issues.[39]

BECCS can play an important role in decarbonising both the power and industrial sectors.[16] In fact, it has been suggested that biomass could deliver a double dividend by displacing fossil fuels whilst removing atmospheric CO_2, and thus should be given more economic incentives than fossil-CCS.[40] However, there is a current lack of incentives towards negative emissions from either the European Union emissions trading system (EU ETS)[40, 41] or other governmental incentives.[42–45]

This work proposes a novel framework that provides accelerated decarbonisation of both industry and power sectors. This strategy repurposes the existing coal-fired power plant fleet into BECCS plants. The BECCS plants are capable of generating both power and negative emissions, which can be auctioned as negative emission credits (NEC) to industry, thereby indirectly

[4]This occurs when a process becomes dependent upon an obsolete technology.

enabling the decarbonisation of the industrial sector. The repurposing of existing infrastructure, combined with two sources of income from NEC and sale of electricity, provides inexpensive, clean electricity without the need for public subsidies. Furthermore, this approach provides a just transition of the power sector workforce,[46] potentially generating more jobs through the creation of a new bioenergy sector.[30] This framework is initially applied to the UK to offset industrial emissions, and subsequently evaluated in a global context.

1.2. Industrial CO_2 emissions

Global CO_2 emissions from the industrial sector are comparable to emissions from the power sector as shown in Fig. 1. As can be observed, industrial CO_2 emission sources are very widespread, extending across large areas. Applying CCS to this sector can prove complex, as large variation of CO_2 concentration from different point sources can exist, even within the same process.[4, 5, 37]

Unlike the electricity sector, industry emits CO_2 at different locations within the same process and often with distinct CO_2 concentrations. Consequently, a wide range of CO_2 avoidance costs[47, 48] can often be detected within the same process (Fig. 2). Industrial CO_2 avoidance costs range from $\$10/t_{CO_2}$ to $\$170/t_{CO_2}$, where the lower costs are associated with high-purity CO_2 sources.[4, 37] Most industrial emissions would have an average cost of $\$80/t_{CO_2}$ by capturing them using CCS.

On a global scale, the industrial sector emits 30% of total anthropogenic CO_2 emissions,[11] where the highest emission industries are iron and steel (accounts for 28% of emissions), cement (27%), followed by chemical produc-

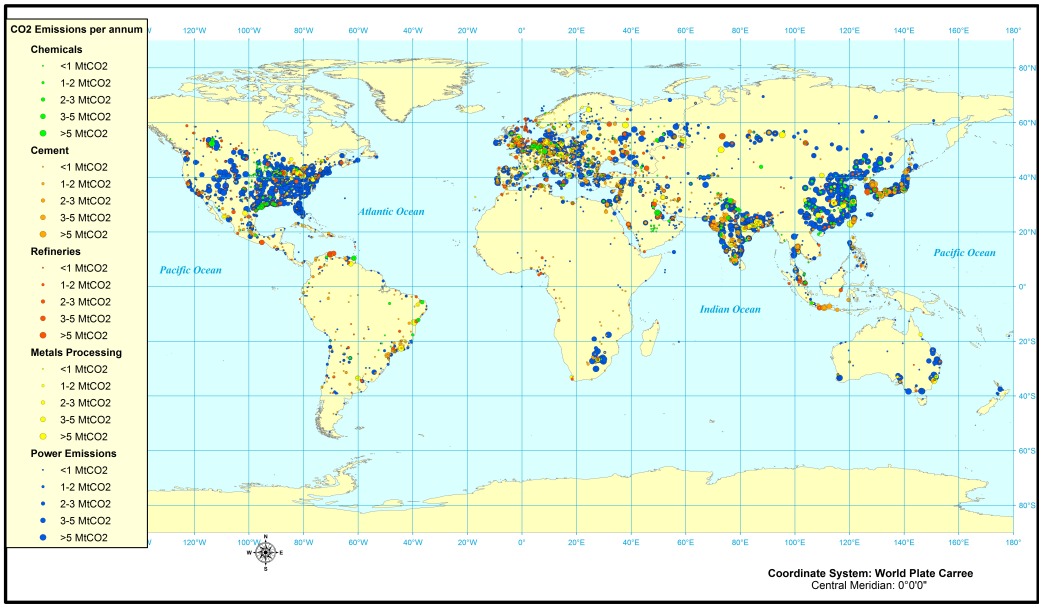


Figure 1: Global distribution of anthropogenic CO_2 emissions from chemicals, cement, refineries, metal processing, and power sector. The image was generated by Imperial College London using data sourced from IEA GHG CO_2 emissions database.[49]

tion and refining processes (13%).[51] In the UK, industry constitutes 17% of total UK CO_2 emissions, which amounted to a total of 18 Mt_{CO_2} in 2015.[52] Refineries and chemical industry contribute 50% of the total UK industrial emissions, followed by 29% from iron and steel, and 11% from cement.[50]

Refineries, iron and steel, and cement combined account for 80 – 90% of total industrial CO_2 emissions in the UK. Thus, these sectors are expected to have a greater contribution towards curbing industrial CO_2 emissions.[37, 47]

Approximately 25% of industrial CO_2 emissions come from sources with high-concentration (30 – 90%) or high-purity (90 – 99%) CO_2, where CCS can be fitted at low-cost.[4, 5, 37, 41, 48] For example, low capture costs

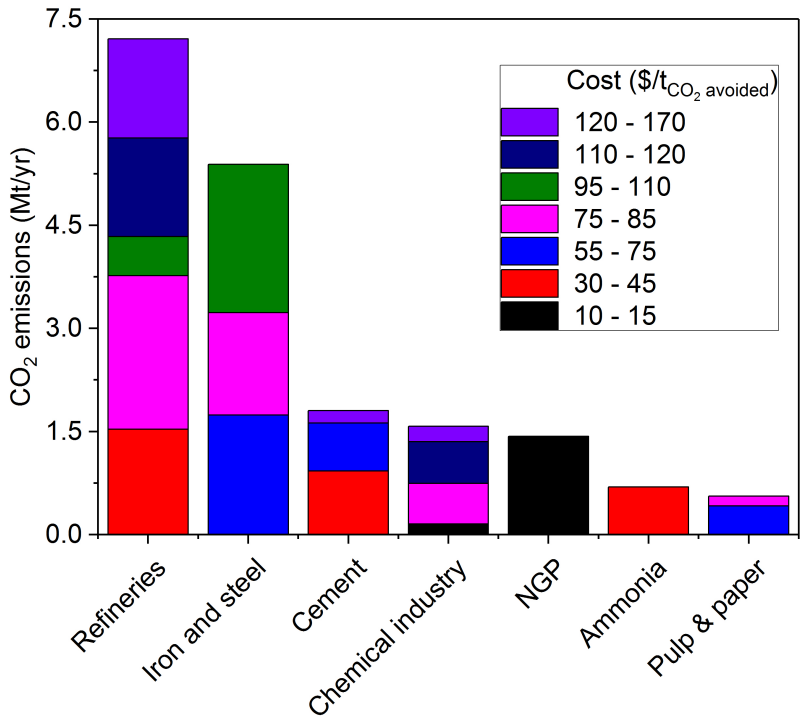


Figure 2: Amount of CO_2 emitted annually in the UK from the industrial sector The costs associated with applying CCS for each point source are classified in ranges, represented by the different colours. Data sourced from[4, 37, 50].

for natural gas processing (NGP) are possible because both CO_2 and H_2S must be removed to achieve natural gas specifications. This results in a stream with 96 – 99% CO_2 that is ready for capture.[41, 48] Fig. 2 shows that low costs of CO_2 avoidance are also observed in the chemical industry, representing processes such as ethylene oxide synthesis where near-pure CO_2 streams can be generated.[41, 48]

In fact, most of the CO_2 currently being used for oil recovery comes from these high-purity sources.[41, 48] In some regions (US and the middle east),

high-purity CO_2 is used for enhanced oil recovery (EOR). However, this is not an option for regions with little or no EOR activity such as the UK, EU, or Asia pacific.[53] For example, half of the CO_2 generated from ammonia production is already utilised either for the synthesis of urea or for EOR, with the remaining being vented to the atmosphere.[41, 48] The exhaust gas streams with lower CO_2 concentration (4 – 30%) tend to be vented without capturing CO_2 due to the higher cost of CO2 avoidance ($\$40/t_{CO_2}$ or more).[37]

Directly implementing CCS will require considerable changes to the industrial process. The process complexity and heterogeneity of industrial CO_2 emissions makes it significantly more difficult to decarbonise via CCS than the power sector. A scheme that offsets industrial emissions through acquiring negative emission credits could be more favourable (technically and economically). Offsetting emissions in this way may be a more cost effective approach compared to applying CCS directly to the industrial process, thus expediting industrial decarbonisation. Customer confidence in the final product may also be maintained this way since there is no deviations from the usual product specification.

1.3. Value of BECCS as a negative emissions and electricity provider

BECCS is a NET that can provide both negative emissions and dispatchable electricity to the grid[7, 8], thereby providing grid flexibility, promoting job creation, and a means of reducing atmospheric CO_2.[7, 30, 54, 55] A sustainable supply of biomass is a vital prerequisite to remove atmospheric CO_2 using BECCS.[9, 54, 56] However, carbon leakage across the biomass supply chain can reduce the amount of CO_2 captured by 10 – 30%, even

when biomass is sourced sustainably.[8, 43, 54, 56–58]

BECCS could be publicly perceived as being green and sustainable (commonly associated with renewable energy), thus it would possibly be more socially acceptable compared to fossil fuel-CCS.[40] Conversely, there exists a persistent controversy surrounding the potential of BECCS to compete with food production, and that it may promote the destruction of forests.[7] Waste biomass feedstocks such as agricultural residues or municipal solid waste (MSW) can reduce the demand of virgin biomass[59], thereby avoiding competition with land used for agriculture. Waste biomass is typically burned in incineration power plants or combined heat and power (CHP) plants[60], which can be integrated with CCS to generate negative emissions.[61, 62]

Other considerations associated with BECCS include the lower carbon content and heating values of biomass compared to coal[63], and high CO_2 capture costs, estimated to be between \$45 and \$250 per t_{CO_2}.[7, 8] The high range of costs arises due to differences between feedstock types, which vary in terms of, *e.g.*, transportation to pellet facility, and pellet production, culminating in fuel costs, currently estimated to be between \$100 – \$210 per t_{pellet}.[64] This also raises the question of which biomass to use, also considering key factors such as overall cost, yield, land availability, and water consumption[40, 54, 56], along with mode of transport, and methodology for drying and pelletisation.[64]

Managing all of these issues requires the development and implementation of systematic supply chain models and performing life-cycle assessments (LCA).[56, 61, 65] Thus, guaranteeing the sustainability of biomass will likely involve continuous monitoring and recertification of the supply

Table 1: Amount of global primary energy from sustainable biomass, extracted from Fuss et al. [8]. A 30% efficient BECCS plant was used to convert between primary energy and electricity generated, and then determined the contribution to global elecricity generated

Parameter	**Pessimistic**	**Median**	**Optimistic**
Primary energy (EJ/yr)	60	130 – 160	350
Electricity (10^3 TWh/yr)	5	11 – 13	29
Contribution (%)	20	42 – 52	120

chain throughout a bioenergy project's lifetime.

It then becomes necessary to understand the availability and distribution of global sustainable biomass that can be used as fuel for BECCS. Previous publications reported that this sustainable amount of biomass is in the range of 60 – 300 EJ/yr of primary energy[8, 66, 67], equivalent to 5000 – 29000 TWh/yr of electricity, assuming 30% BECCS plant efficiency as the world average (Table 1).[68] The potential for BECCS power generation in the conservative median scenario is analogous to that of the global power generation capacity of the existing coal fleet worldwide in 2017, approximately 10,000 TWh.[29]

There should be plentiful sustainable biomass to promote this transition[8] with several implications. First, switching the fuel source of existing power plants around the world would only experience minor conversion costs[69] with additional costs associated with the application of CCS Repurposing of existing coal plants would reduce overall cost when compared to a new project. Next, coal-related jobs and existing infrastructure will be safeguarded through preventing premature decommissioning.[30] Indeed, the plant can start by increasing the share of co-fired biomass in the early years of

fuel switching, *i.e.*, progressively ramp up biomass firing proportion, therefore facilitating a socially accepted fuel transition. Lastly, this would simultaneously decarbonise both the power and industrial sectors, getting us to 2050 in an expedited fashion, allowing us to avoid stranded power/industrial assets and delivering subsidy-free BECCS electricity.

1.4. Oxy-combustion of biomass

Oxy-combustion is a promising CCS technology where air is replaced by a stream of high-oxygen (O_2) concentration. Eliminating the presence of nitrogen (N_2) decreases total oxidant flowrate thereby improving combustion efficiency.[70–72] The high amounts of oxidant required can only be satisfied using the technically mature cryogenic air separation unit (ASU) technology[73, 74] at the expense of 190 – 240 kWh/t_{O_2}, depending upon process design.[75–81]

Temperatures close to those observed in air-fired conditions are achieved by recycling 70% of the flue gas back to the furnace[71, 79, 82–86], avoiding the need for O_2-specific materials[87]. A flue gas with 60 – 70 mol% of CO_2 is generated depending upon fuel used, which must be further purified to transport specification in a gas processing unit (GPU).[83, 88–90] Because this GPU doesn't rely on a solvent-based system, the upstream emissions of oxy-CCS are reduced to zero by eliminating the CO_2 emissions associated with solvent production and supply chain.[91] Thus making the GPU a potentially superior option to solvent-based CCS on a whole-life basis[91] with a power consumption between 100 and 180 kWh/t_{CO_2} depending on the purity required.[80, 81, 89] Hence, a total efficiency penalty of 8 to 12%[80, 88] is obtained when implementing oxy-combustion for capture rates greater than

90%.[71, 79, 92, 93]

The viability of oxy-combustion has been demonstrated by Vattenfall's pilot plant[94, 95], Compostilla OXYCFB300[96], Callide oxyfuel project[84, 97, 98], and Lacq pilot plant.[99] These projects have identified operational issues and design parameters that, coupled with computational fluid dynamics (CFD) analysis, could pave the way for large-scale projects.[100]

Importantly, the combustion of cereal co-product[85, 101], wood pellets[101], miscanthus pellets[101], olive waste[102], sugarcane bagasse[103], pine sawdust[93, 103, 104], and municipal solid waste (MSW)[105] have been successfully tested under oxy-combustion conditions. Biomass can therefore be expected to possess similar behaviour as coal when burnt under oxy-combustion conditions. However, there may be higher maintenance cost associated with biomass combustion due to increased slagging, agglomeration, and corrosion.[106]

Biomass power plants are currently in operation, such as the Drax plant in North Yorkshire, UK using wood pellets,[107] and in Shenzhen, China, using MSW.[105] Hence biomass combustion is a proven concept, already commercial, and ready for deployment.[9]

The concept of oxy-BECCS has been demonstrated experimentally,[85, 93, 101–104] and has been the subject of a number of techno-economic studies.[108, 109] It is therefore a viable concept, with Drax announcing a pilot plant in collaboration with C-Capture[110], proving this idea is worth pursuing further.

2. Framework for negative emissions generation

2.1. Oxy-BECCS model description

Simulation of the oxy-combustion process was performed using gPROMS software. The plant is assumed to generate 500 MW_{net} electricity, representing a large coal-fired power plant[79], maintained throughout the simulations for each biomass co-firing rates, thus guaranteeing the results were comparable. Captured CO_2 was compressed to pipeline pressure, assumed to be 110 bar.[90]

The framework proposed herein is illustrated in Fig. 3 along with the main inputs/outputs from each unit operation. The cycle starts with biomass capturing atmospheric CO_2 for growth, pelletised, and then used as fuel, accounting all emissions associated with this processing and transportation. The fuel, which can either be biomass or a blend with coal, is burnt with a stream comprised of O_2, generated by an ASU, and recycled flue gas (RFG). The remaining flue gas is sent to the GPU where CO_2 is purified to 99 mol% and compressed to pipeline specifications. Ultimately this high-purity CO_2 stream is stored in a reservoir, which can be a depleted oil field, a deep saline aquifer, or other suitable reservoir.[111]

In this work, each unit operation was simulated according to Green and Perry [112] using Peng-Robinson equation of state to calculate the thermodynamic properties of all streams. An exception was made for water, where SAFT-γ Mie group contribution equation of state was used.[113]

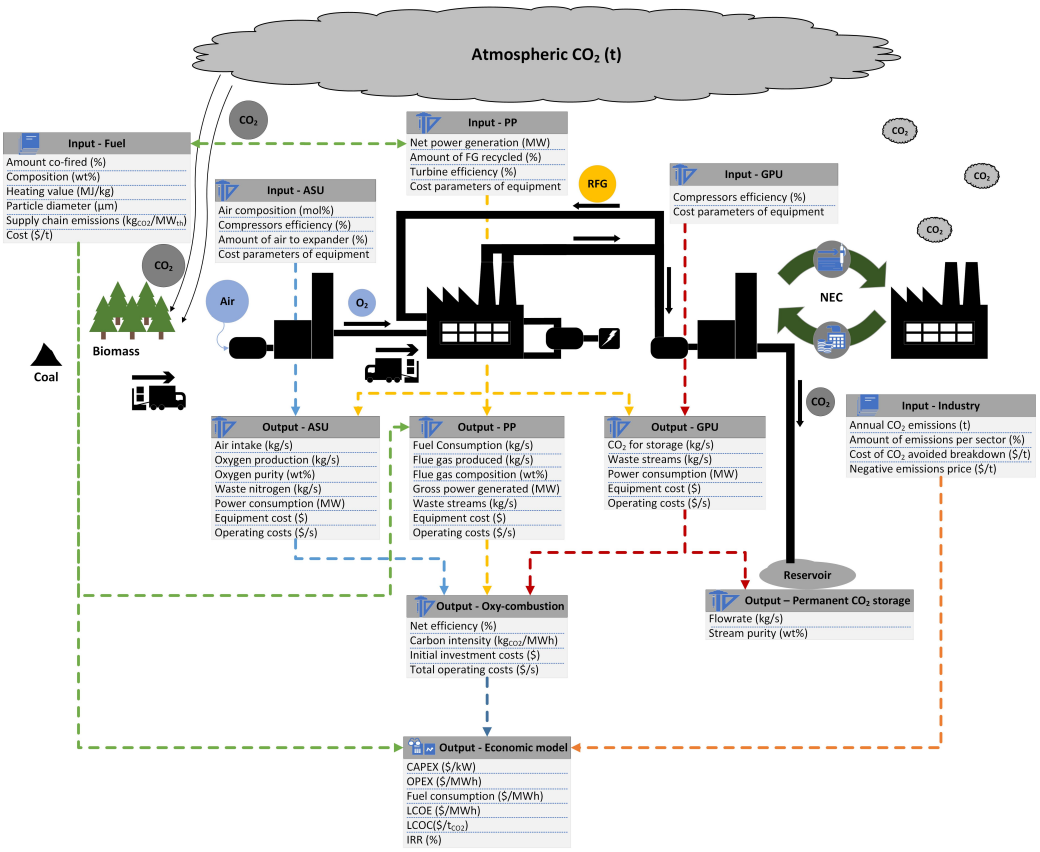


Figure 3: Process flow diagram of the approach proposed herein to offset industrial CO_2 emissions. Biomass captures atmospheric CO_2 for its growth, harvested, pelletised and used as fuel in the power plant (PP) to generate electricity. The oxygen required to burn the fuel is produced by an air separation unit (ASU). Part of the flue gas generated from the combustion process is recycled to the furnace, whilst the remaining is sent to a gas processing unit (GPU). Here, CO_2 is purified and compressed to pipeline specifications. Negative emissions arising from storing biogenic CO_2 in a reservoir are auctioned as negative emission credits (NECs) to offset industrial emissions. The cycle is then closed by CO_2 emitted from industrial processes being captured again by biomass. Mass flows between each process are represented by black lines with arrows indicating the direction of flow. Dashed arrows represent the flow of information between the inputs and outputs from each process in the model.

2.2. Determining power plant efficiency

Steam produced in the power plant expands in a series of turbines (see Appendix B for more detail) to generate electricity, known as the gross power ($Power_g$). The actual amount of electricity dispatched to the grid, known as net power ($Power_{net}$), must discount the parasitic power consumption from the other unit operations ($Power_{cons}$).

$$Power_{net} = Power_g - \sum Power_{cons} \tag{1}$$

The net efficiency of the process (η_{net}) (%) is obtained by relating the net power generated with the heat generated from combustion ($m_{fuel} \times HV_{fuel}$).

$$\eta_{net} = 100 \times \frac{Power_{net}}{m_{fuel} \times HV_{fuel}} \tag{2}$$

This equation is valid for both higher and lower heating values, and can also be used to evaluate the gross efficiency by switching the net power with gross power generated. Consequently, the efficiency of transforming heat into electricity is quantified, allowing the comparison with other electricity-generating processes.[5]

2.3. Achieving negative emissions

Negative emissions are achieved when non-biogenic (or anthropogenic[6]) CO_2 emissions from oxy-combustion are less than the biogenic CO_2 stored

[5]It must be noted that this metric is used for electricity generated by heat. Comparing the efficiency of a fossil-fueled process with a renewable process (such as wind or PV) must consider other factors, such as fuel cost/availability, amongst others.

[6]Anthropogenic CO_2 emissions are all CO_2 emissions generated from human activity, such as combustion of fossil fuels, land use change, amongst others. In this work the

in the reservoir. In this study, biogenic CO_2 emissions ($e^{biogenic}_{CO_2}$) (kg/h) are considered carbon neutral. Hence actual CO_2 emissions ($e^{actual}_{CO_2}$) must discount them from the total amount of CO_2 released ($e^{total}_{CO_2}$), which accounts CO_2 from fossil-fuels and supply chain.

$$e^{actual}_{CO_2} = e^{total}_{CO_2} - e^{biogenic}_{CO_2} \tag{3}$$

Accordingly, the amount of biogenic CO_2 captured ($c^{biogenic}_{CO_2}$) (kg/h) is the total CO_2 captured ($c^{total}_{CO_2}$) without CO_2 from fossil-fuel sources ($c^{fossil}_{CO_2}$).

$$c^{biogenic}_{CO_2} = c^{total}_{CO_2} - c^{fossil}_{CO_2} \tag{4}$$

Carbon intensity (CI) relates the amount of CO_2 emissions per MWh of electricity generated (kg_{CO_2}/MW_eh) and is a useful metric to assess the emission potential of a process.

$$CI = \frac{e^{actual}_{CO_2} - c^{biogenic}_{CO_2}}{Power_{net}} \tag{5}$$

If CI is negative, then the process is carbon negative, if it equals zero the process is carbon-neutral, and it is considered carbon-positive if greater than zero. When the process is carbon-negative, it is possible to auction the negative CO_2 emissions as credits creating a potential synergy between BECCS and the industry aiming to offset its emissions.

The number of BECCS plants with the chosen net capacity (here taken as 500 MW_e) required to offset global industrial CO_2 emissions ($e^{gi}_{CO_2}$) can

sources of these emissions are the fuel supply chain and CO_2 emissions from coal when it is being burnt.

then be calculated.

$$No.\ plants = \frac{e^{gi}_{\mathrm{CO_2}}}{-CI \times Power_{net}} = \frac{e^{gi}_{\mathrm{CO_2}}}{c^{biogenic}_{\mathrm{CO_2}} - e^{actual}_{\mathrm{CO_2}}} \tag{6}$$

2.4. Fuel

A Bituminous Eastern Australian coal and clean wood chips with composition, heating value, supply chain emissions, and cost[7], detailed in Table 2, were used as fuel in this study. The use of clean wood chips mitigates slagging, agglomeration and corrosion issues.[68] Supply chain emissions for biomass were assumed to be 110 $\mathrm{kg_{(CO_2)}/MWh_{th}}$ [107] and 307 $\mathrm{kg_{(CO_2)}/MWh_{th}}$[114] for coal.

Fuel composition and heating value are key parameters in determining the combustion reaction that provides both composition and temperature of the flue gas (Appendix Appendix B). Supply chain emissions (SCE) impact the carbon intensity of the fuel, and fuel cost is important to evaluate the economics of the project. The remaining parameters in Table 2 ($\mathrm{F_{80}}$, $\mathrm{P_{80}}$, and G) are used to simulate the grinding process, thus determining the power consumption of this unit, and consequently the efficiency of the power plant (Appendix Appendix B).

[7]Cost of coal was changed from € to $ assuming the 2014 exchange rate of 1.33 $/€. Cost of wood-chips reflects the assumption that they were sourced locally (UK). If US imported biomass was used, the cost would rise to $210/t.

Table 2: Fuel composition, heating value, supply chain emissions (SCE), grindability parameters, and cost

Fuel Component (wt%)[63, 79]	**Coal**	**Wood chips**
C	64.6	47.6
H	4.4	5.1
S	0.9	0.05
O	7.0	40.2
N	1.4	0.3
H_2O	9.5	4.8
Ash	12.2	1.95
HHV_{ar} (MJ/kg)[63, 79]	34.6	19.5
SCE (kg_{CO_2}/MWh_{th})[107, 114]	307	84 - 136
F_{80} (μm)[115]	2709	8400
P_{80} (μm)[115]	77	786
G (g/rev)[115]	0.664	0.053
Cost ($/t)[63, 79]	86	117

2.5. Economic model

Equipment cost, labourers per shift, and techno-economic analysis were obtained following the procedure described by Couper et al. [116, 117] with the assumptions described in Table 3. [79, 117] Start-up costs of 2% total plant cost, 25% of full capacity fuel cost for one month, and three months of operating and maintenance labour costs were assumed in this study, according to IEA GHG.[79] This model is considered a factored estimate, having an accuracy between - 25 to + 30%, and can be applied for any geographical location.[117] The plant is assumed to operate at 65% load factor during the

first year, 85% during the second, and 90% from the third year until end of project.[79]

Table 3: Assumptions used for the techno-economic analysis of the proposed framework

Parameter	**Value**	**Units**
Currency	US Dollar	$
Year	2015	
Contingency[79]	10% Fixed capital	$
CO_2 emissions cost[79]	25	$/$t_{CO_2}$
CO_2 T&S costs[79]	13	$/$t_{CO_2}$
Economic calculation	Discounted cash flows	
Number of operators (NO)[117]	5 × Labourers per shift	
Operating labour (OL)[79]	79800 × NO	$
Supervision[79]	30% OL costs	$
Maintenance[79]	10% Fixed capital	$
Royalty[117]	1% Sales	$
Indirect expenses[117]	3% Fixed capital	$
Interest rate (r)[79]	8	%
Inflation during construction[79]	8	%
Economic lifetime[79]	25	years
Construction time[79]	3	years
Yearly operating hours[79]	7885	h

The economic model identifies some key performance indicators (KPI) of the simulated oxy-combustion process, namely capital and operational expenditure, levelised and marginal cost of electricity, and the internal rate of return (IRR).

2.6. The cost of electricity

The levelised cost of electricity (LCOE), expressed in $/MWh, is a metric commonly used to measure the economic potential of different generating technologies. It reflects the discounted lifetime costs of generating electricity and can be calculated according to the following equation:[118]

$$LCOE = \frac{CAPEX + \sum_{n=0}^{lt} \left[\frac{OPEX_n}{(1+r)^n} \right]}{\sum_{n=0}^{lt} \left[\frac{MWh_n}{(1+r)^n} \right]} \tag{7}$$

Where $CAPEX$ is the plant's capital expenditure ($), $OPEX_n$ is the operating expenditure of year n ($/kWh), lt is the plant's lifetime (years), r is the interest rate, MWh_n is the amount of electricity generated during year n, and n is the year.

The marginal cost of electricity ($MCOE$) represents how much it costs to operate the plant, and is calculated using the following equation:

$$MCOE = \frac{\sum_{n=0}^{lt} \left[\frac{OPEX_n}{(1+r)^n} \right]}{\sum_{n=0}^{lt} \left[\frac{MWh_n}{(1+r)^n} \right]} \tag{8}$$

The levelised cost of carbon (LCOC) represents the costs associated with storing 1 ton of CO_2, calculated using the following equation:

$$LCOC = \frac{CAPEX + \sum_{n=0}^{lt} \left[\frac{OPEX_n}{(1+r)^n} \right]}{\sum_{n=0}^{lt} \left[\frac{\mathrm{CO_2\ } stored}{(1+r)^n} \right]} \tag{9}$$

Assuming OPEX, electricity generation, and the amount of CO_2 stored throughout the plant lifetime are constant, these can be broken down as geometric series as follows:

$$\sum_{n=0}^{lt} \left[\frac{\alpha_n}{(1+r)^n} \right] = \alpha \times \left(\left[\frac{1 - \left(\frac{1}{1+r}\right)^{lt}}{1 - \left(\frac{1}{1-r}\right)} \right] - \left[\frac{1 - \left(\frac{1}{1+r}\right)^{ct}}{1 - \left(\frac{1}{1-r}\right)} \right] \right) \tag{10}$$

Where α can be either $OPEX$, MWh, or $\mathrm{CO_2\ } stored$, ct is the plant's construction time (years), η_i is the efficiency being iterated, and η_{net} is the net efficiency of the plant associated with the CAPEX and OPEX selected.

2.7. Internal rate of return

Operating the oxy-combustion process generates yearly cash flows (CF_t) which can be discounted to present day values assuming a discount rate (r). The net present value (NPV) of a project can then be calculated by summing all discounted CFs and deducting the initial investment costs (C_0).

$$NPV = \sum_{n=0}^{lt} \left[\frac{CF_n}{(1+r)^n} \right] - C_0 \tag{11}$$

The internal rate of return (IRR) is the interest rate that generates a zero net present value from all cash flows.

$$\sum_{n=0}^{lt} \left[\frac{CF_n}{(1+IRR)^n} \right] - C_0 = 0 \tag{12}$$

The IRR is routinely used by investors to estimate the profitability of a project by comparing it with the IRR from other projects, generally already established ones. In general, high IRR are desirable, so the project with higher value is usually selected when using this metric to choose between different projects.

2.8. CO_2 avoided costs

Costs of CO_2 avoided ($/t$_{CO_2}$) were calculated using unabated coal plant emissions (t_{CO_2}/MWh) and LCOE ($/MWh) from IEAGHG[79] as reference and the results obtained in this study, using the following equation:

$$CO_2^{Avo}\ costs = \frac{LCOE_{CCS} - LCOE_{Reference}}{\mathrm{CO_2}_{Reference}^{Emission} - \mathrm{CO_2}_{CCS}^{Emission}} \tag{13}$$

This metric identifies the cost associated with applying CCS to a plant, and is often used to compare a group of CCS projects. It is a useful metric in identifying the lowest-cost CCS project, which can be beneficial when limited funding is available. Despite its usefulness, this metric says nothing regarding the plant's profitability in a given context, hence it should still be accompanied by an economic analysis.

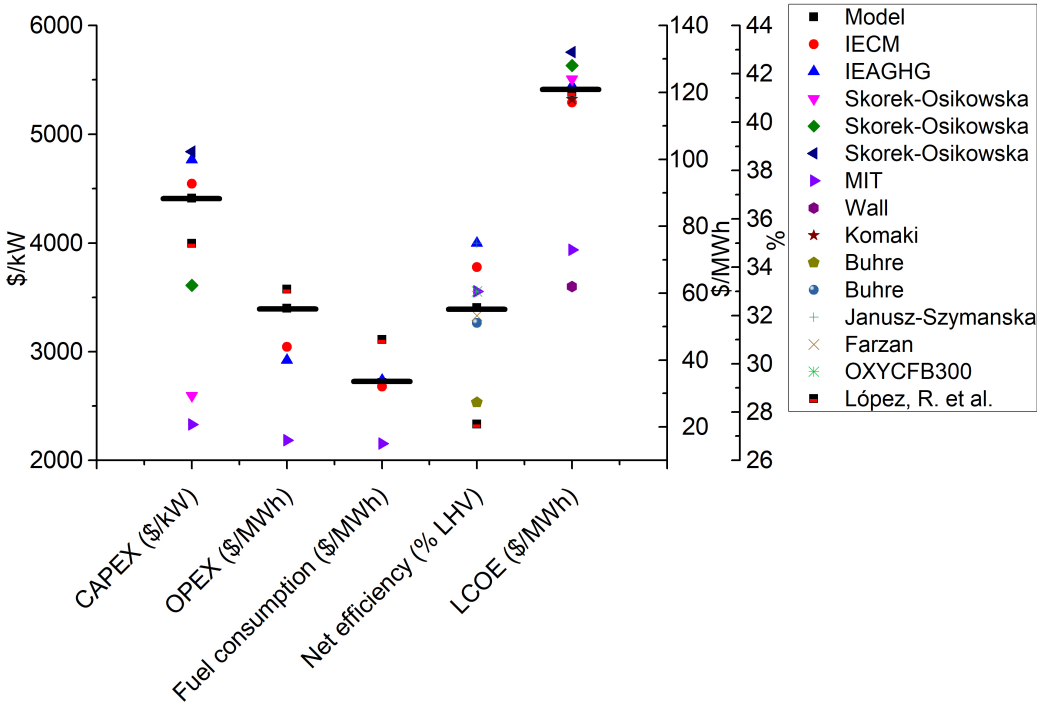


Figure 4: Validation of the oxy-combustion model against the main performance indicators capital cost (CAPEX), operating cost (OPEX), fuel consumption, net power generation efficiency and levelised cost of electricity (LCOE)[78, 79, 96, 97, 109, 119–124]. The horizontal lines represent this model's values.

3. Analysing the synergy between BECCS and industry

3.1. Model validation

An ultra-supercritical coal-fired oxy-combustion process was simulated herein, obtaining a net efficiency of 32% and a CAPEX of \$4400/kW. The computed OPEX, fuel consumption, and LCOE were \$56, \$33, and \$120 per MWh, respectively (Fig. 4), and a CO_2 avoidance cost of $\$72/t_{CO_2}$.

The results obtained from this simulation must first be compared with

the literature as a validation step before further analysis. As can be seen by the horizontal lines in Fig. 4, this model shows good agreement with the literature.[78, 79, 96, 97, 109, 119–125] It can be observed that the results obtained from this simulation fall within zones with high-density of data points. Importantly, the comparison of the different literature values demonstrate that cost estimates are overall within the same order of magnitude of each other. The variation in literature values may be due to differences in the techno-economic assumptions made by the respective authors, *e.g.*, equipment and labour costs, interest rate, power capacity, and coal rank.

A statistical analysis was then performed by assessing the normality of LCOE using D'Agostino and Pearson's test[126] with SciPy library from Python 3.6. By using in-house data in addition to the literature values, the outcomes of the statistical analysis were improved. An array of LCOE values were calculated using the economic model described in section 2.5. Calculations were based on combinations of CAPEX, OPEX, fuel consumption, and plant efficiency obtained from literature.

The computed LCOE falls within 68% of the confidence interval of the normal probability density function (PDF) determined using an array of 400 LCOE values. This PDF has a mean (μ) and standard deviation (σ) of \$111 and \$23 per MWh, respectively, and a p-value of 0.04 (Fig. 5), showing that the LCOE follows a normal distribution.

The lower values encountered for CAPEX and OPEX in some references (Fig. 4) may have shifted the mean towards \$110/MWh, as can be seen by higher than expected bars at \$60 and \$90 per MWh (Fig. 5). This reflects upon the high standard deviation observed, suggesting that more

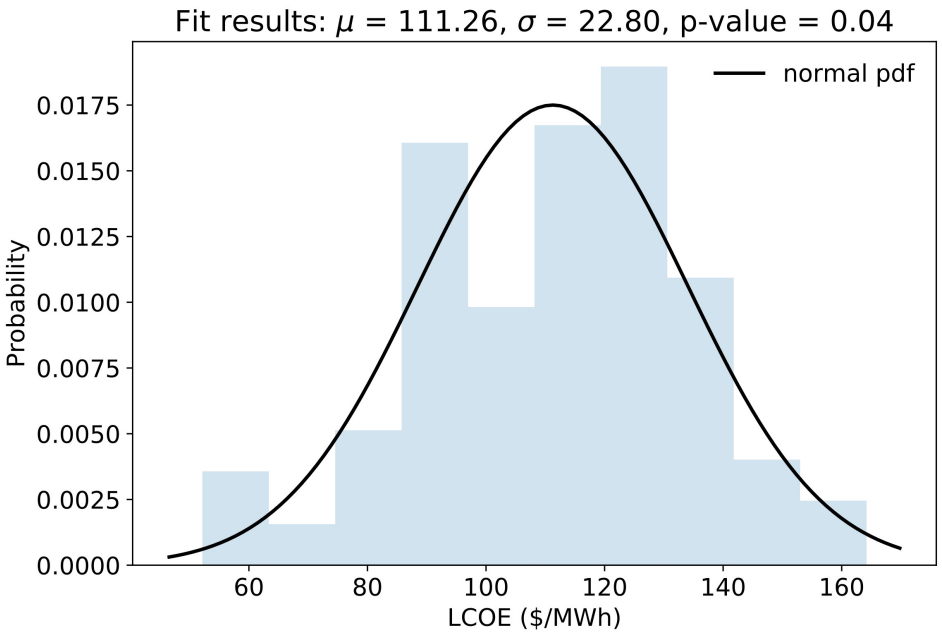


Figure 5: Normal probability density function (PDF) of LCOE. The amount of data required to construct the PDF was obtained by calculating the LCOE from combinations of CAPEX, OPEX, and net power efficiency from literature (See Fig 4).

data on oxy-combustion is required to increase the confidence of decision-makers towards this technology.

The performance indicator values that cluster together have made similar assumptions, thus resulting in more than one PDF with their own mean and standard deviation. Using this approach to compare results from different data sources can help assess the overall impact of specific study assumptions, also determining whether they were statistically significant (*e.g.* another assumption made across a different set of studies that leads to the clustering

of results). Understanding which and how key assumptions impact the overall economic performance of the project will allow us to better design a process, thus minimising its costs.

In summary, the fact that the results of these calculations fall within one standard deviation of available literature data is a strong endorsement of the validity of the model developed in this work.

3.2. Economic impact of BECCS-generated electricity

Increasing the amount of biomass causes a non-linear increase in CAPEX, OPEX, fuel consumption and LCOE, whilst concurrently reducing the plant's efficiency (Fig. 6). The sudden small decrease/increase sometimes observed on the efficiency (Fig. 6) are simulation artefacts (*e.g.*, at 75% biomass co-firing).

Switching from coal to biomass imposes an efficiency penalty of up to 3%, considering that significantly more fuel, on a mass basis, is required to achieve the same power output (Fig. 6 and Table 4). This is explained by the lower HHV of this biomass compared to a bituminous coal (Table 2). Higher fuel consumption combined with the higher costs of wood-chips (Table 2) results in a substantial increase to fuel cost, nearly doubling plant's OPEX (Table 4). Another factor influencing OPEX is the increased power required to run the mill, since biomass has higher Bond work index (BWI)[115] than coal, making it harder to reduce its size. Furthermore, the higher flowrates required when firing biomass increases equipment size, which translates to 14% higher CAPEX requirement.

Firing wood-chips instead of coal leads to a 45% and 30% increase in both LCOE and LCOC, respectively (Table 4). This high LCOE increase

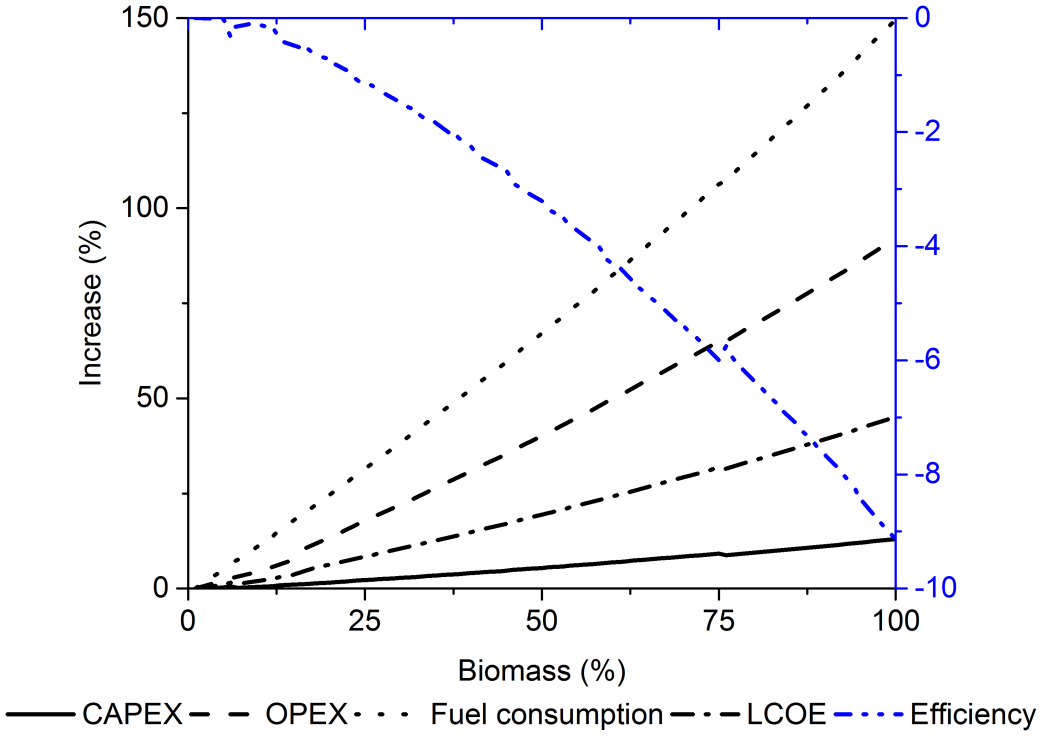


Figure 6: Amount of CAPEX, OPEX, fuel consumption, LCOE (black), and efficiency (blue) increase due to increased amounts of biomass co-fired.

has also been noted in a previous study[93] for a 350 MW_{net} power plant, which suggests that it can increase up to 95%.

The LCOE of \$175/MWh and LCOC of \$150/t_{CO_2} obtained for biomass, assuming no income from negative emissions, (Table 4) lie in the range reported in the literature.[7, 55, 108, 109, 127] This analysis assumes that all of the costs associated with BECCS must be borne by either the CO_2 removal service, or the power generation service. In reality, this is unlikely to be the

Table 4: CAPEX, OPEX, fuel consumption, LCOE, and LCOC for oxy-combustion using coal and wood-chips

Parameter	**Coal**	**Wood chips**	**Units**
CAPEX	4400	5000	\$/kW
OPEX	56	107	\$/MWh
Fuel consumption	33	83	\$/MWh
LCOE	120	175	\$/MWh
LCOC	115	150	$\$/t_{CO_2}$
η_{net}^{LHV}	32	29	%

case, with each service being arbitraged separately.[128] The core hypothesis of this paper is that a BECCS plant could expect to provide an emissions offset service to a 3rd party, *e.g.*, the industrial sector, whilst simultaneously providing a power generation service to the electricity grid. The consequence of this is that both services could therefore be provided for less than their individual levelised costs.

3.3. Potential of NECs to offset global industrial emissions

As can be seen from Fig. 2, there is potential to offset 18 Mt_{CO_2}/yr from UK's industry by auctioning NECs. A 500 MW_{net} dedicated oxy-BECCS plant can effectively remove 3 Mt/yr of atmospheric CO_2, similar to what has been reported by Kemper [40]. Hence, only 6 plants operating under these conditions would be required to offset all the industrial emissions in the UK. This strategy could potentially be applied for the accelerated decarbonisation of other hard-to-reach sectors in the UK such as aviation. This approach would be a major step towards reaching the target of net-zero emissions in

the UK by 2050.[13, 15]

Global emissions from industry and fossil fuels were estimated at 12 Gt_{CO_2} in 2016 according to the Global Carbon Budget.[10] Assuming the same emission distribution per sector as the UK, there is potential to offset 9 Gt_{CO_2}/yr worldwide from medium-, and low-concentration CO_2 sources by deploying 3000 oxy-BECCS plants using this strategy. The amount of negative emissions providing this decarbonisation service is similar to the reported maximum amount of sustainable negative emissions of 10 Gt_{CO_2}/yr for BECCS.[8, 40, 129] Indeed, the International Energy Agency (IEA) has envisioned a global amount of 3400 CCS plants by 2050 to meet the global targets according to the BLUE Map scenario.[130] If larger capacity plants were to be used the number of projects required would be lower, potentially making this a cost-effective alternative to incorporating CCS directly to industrial processes.

There are two deployment options for BECCS: (i) building entire new plants (*i.e.*, greenfield), or (ii) utilising existing infrastructure (*i.e.*, brownfield, where existing coal-fired power plants are converted to dedicated biomass-fired plants). The brownfield approach potentially jump-starts development and provides an accelerated roll-out of BECCS technology, thereby expediting the removal rate of atmospheric CO_2. Re-commissioning existing coal-fired plants reduces capital cost of infrastructure for BECCS, however this approach will have lower efficiency than greenfield plants[131, 132] and thus higher CO_2 capture cost.[131]

Here, we propose 3000 oxy-BECCS plants to offset global industrial emissions, which have a total electricity generation capacity of 12,000 TWh/yr.

As shown in Table 1, there is sufficient sustainable biomass available worldwide to meet this generation capacity and the proposed strategy is feasible. As noted earlier, the existing fleet of coal-fired power plants worldwide has a capacity of 10,000 TWh (in 2017)[29], which is comparable to the proposed global BECCS capacity required for this strategy. The re-purposing of the existing coal infrastructure into biomass-fired plant is feasible. Benefits of this approach is a potential net gain in the number of jobs (*e.g.*, retaining jobs in plant operations, and gain jobs in forestry, agriculture and logistics), as well as avoidance in costs associated with prematurely decommissioning coal power plants.[30]

Newer plants are better suited for being re-commissioned into BECCS by taking advantage of the reduced costs arising from their increased efficiency. A third of the global coal capacity is less than 10 years old.[133] There is high potential to develop brownfield BECCS infrastructure in Asia because 85% of global coal power investment are in this region (most with less than 10 years).[133–135] There is the potential to retrofit 310 GW of the existing coal power plant infrastructure with CCS, which constitutes 55% of the coal-fired capacity.[64, 136] Re-purposing existing coal-fired power plants to BECCS has the potential to help these countries achieve ambitions of reducing local air pollution[133] whilst avoiding loss of their investment. The conversion of unabated coal-fired power plants into BECCS generates negative emissions whilst also avoiding emissions from fossil fuel use (*i.e.*, displacement of fossil fuel power for bioenergy).

3.4. How supply chain emissions impact the costs of BECCS

As has been discussed previously[56–58], there is the potential for substantial carbon leakage throughout the BECCS supply chain, which will reduce the quantity of CO_2 that can be removed from the atmosphere by a given BECCS project. This has historically resulted in significant concern for the viability of BECCS as a negative emissions technology. If the technology does not provide in the removal of material quantities of CO_2 from the atmosphere, how is it helpful? Through the framework proposed here, we show that it will be in the direct commercial interest of the project proponents to minimise this carbon leakage, thus ensuring BECCS projects are developed in as constructive way as possible.

Generating negative emissions from BECCS is paramount for this framework, hence it becomes necessary to understand the limits where using biomass is sustainable. This is achieved by varying biomass supply chain emissions and assessing its effect on the LCOE, MCOE, and CI. The increase of LCOE and MCOE caused by higher amounts of wood-chips co-fired is evident (Fig. 7 a and b), confirming the results observed earlier (Fig. 6). However, a difference of both LCOE and MCOE caused by supply chain emissions can only be observed at lower amounts of wood-chips co-fired, whilst no effect is detected at higher amounts. This effect follows the path when CI is zero, *i.e.*, the process becomes carbon-neutral (Fig. 7 c).

Carbon intensity increases with higher biomass supply chain emissions and amount of coal co-fired (Fig. 7 c) because coal has higher supply chain emissions (Table 2). It is worth noting that carbon negativity can be achieved even at high supply chain emissions for biomass co-firing above 45%.

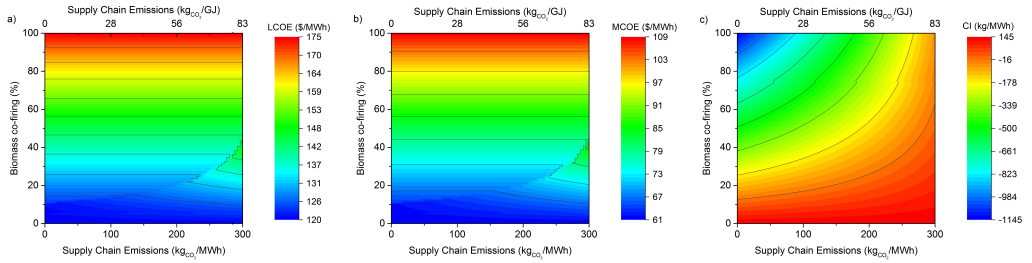


Figure 7: Effect of biomass co-firing (%) and supply chain emissions with \$25/t carbon price[79] on a) Levelised cost of electricity (LCOE) (\$/MWh), b) Marginal cost of electricity (MCOE) (\$/MWh), and c) carbon intensity (CI) (kg_{CO_2}/MWh). Supply chain emissions can increase the LCOE and MCOE whilst carbon intensity is positive, characterised by the discontinuities observed in a and b. This corresponds to the point when CI = 0 kg_{CO_2}/MWh, *i.e.* the amount of biogenic CO_2 is not enough to displace total oxy-combustion emissions This effect can be discerned by the cost increase because of larger emissions from the supply chain for smaller amounts co-fired. Increasing the amount of biomass lets the process achieve net-negative emissions, at which point the supply chain ceases to have any detrimental effect on both LCOE and MCOE.

Comparing Fig. 7 a, b, and c illustrates the profound impact that supply chain emissions have on the amount of atmospheric CO_2 being removed. These emissions can increase both LCOE and MCOE when overall CO_2 emissions are positive, *i.e.*, the BECCS plant would actually be required to pay for emitting CO_2 to the atmosphere.

3.5. Negative emission credits: paving the way for cost-competitive CCS

LCOE values presented previously assign all costs to the production of electricity, and neglect to assign any value to the removal of CO_2 from the atmosphere. This makes BECCS a very costly activity and thus difficult

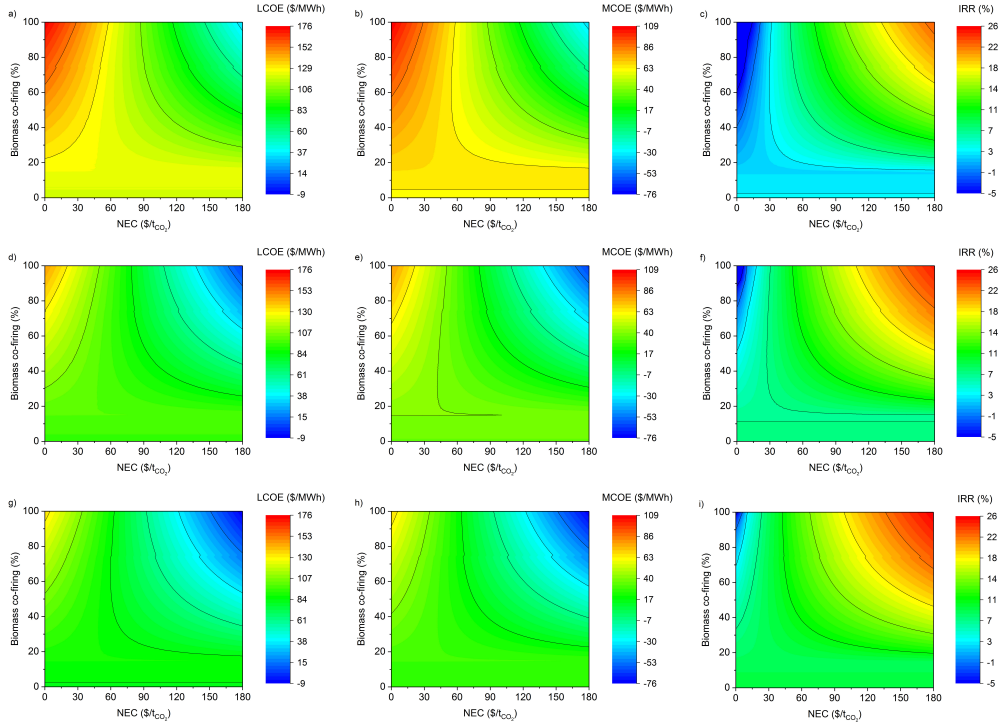


Figure 8: Effect of NEC and wood chips co-fired on a, d, g. LCOE ($/MWh); b, e, h. MCOE ($/MWh); and c, f, i. IRR (%); assuming supply chain emissions of 110 kg_{CO_2}/MWh for unsubsidised plants (a, b, and c), and subsidies of 35 (d, e, and f) and 50 (g, h, and i) $\$/t_{CO_2}$.

to support. Auctioning negative emissions credits to an otherwise carbon-constrained industry sector is one way of accruing value to BECCS plants without requiring a significant shift in the prevailing policy paradigm.

Fig. 8 explores the effect of auctioning NECs at a variety of biomass co-firing rates. LCOE can be reduced up to 80% by auctioning NECs whilst increasing IRR from 2% for coal-fired up to 23% for biomass-fired. It is important to note that firing biomass has lower MCOE than coal when auction-

ing NECs above \$70/t_{CO_2}, even achieving negative values above \$130/t_{CO_2}, implying that marginal costs are being covered by NECs.

Subsidising BECCS plants at \$50/t_{CO_2} reduces the LCOE by 16% if NECs are auctioned at \$100/t_{CO_2} (Fig. 8); this value of NEC is within the range industry would need to pay for directly applying CCS (Fig. 2). It is fascinating to observe that LCOE remains nearly constant at \$115/MWh when auctioning NECs at \$75/t_{CO_2} and co-firing above 25%, indicating that oxy-BECCS is as competitive as an oxy-coal with CCS technology. This \$75/t_{CO_2} NEC is close to the CO_2 price of \$70/t_{CO_2} observed as the threshold of economic potential for BECCS by the IEAGHG.[129] In fact, a LCOE increase is observed until approximately 17% co-firing, followed by a decrease as higher co-firing ratios are achieved. At this stage, the revenues obtained from the NECs start to compensate the increased marginal costs.

Auctioning NECs between \$30 and \$45 per t_{CO_2} generates IRR at 3 – 4%, typically encountered in public investments.[128] If these NECs are increased to above \$90/t_{CO_2} we would find that this process becomes attractive for private investment, with IRR of 11 – 14%.[128] At NEC of 70 \$/t_{CO_2}, co-firing biomass at 40% or above is profitable with an IRR of 6 – 10%. Increasing biomass co-firing rate can achieve even higher IRRs. Hence, dedicated biomass plants have better economic performance at higher auction prices.

Directly trading NECs between BECCS and industry sectors can provide a path towards curbing CO_2 emissions. In fact, such activity provides an extra source of income to the BECCS plant, thus reducing the high costs associated with operating this plant. This collaborative approach between the power and industry sectors would enable the large-scale deployment of

CCS and NETs without the need for public subsidies.

4. Conclusions

To achieve the target of 1.5 °C global warming, the rate of decarbonisation needs to rapidly accelerate across all sectors. The greatest challenge is the reduction of CO_2 emissions in hard-to-reach sectors such as industry, transport and aviation. It has been demonstrated that repurposing the existing coal fleet to BECCS is both feasible and sustainable whilst preserving existing jobs and even promoting the creation of new jobs.

This strategy enables simultaneous decarbonisation of both industrial and electricity sectors in a cost-effective way. Also, this approach provides industry with a smoother transition to decarbonisation, allowing more time to develop new technologies, strategies, and allow costs for CCS to decrease (*e.g.*, through technology learning). The advantage of this framework lies in its simplicity of valuing negative emissions, where NETs are auctioned directly according to the amount of atmospheric CO_2 captured.

Auctioning NECs introduces another source of revenue to the BECCS plant, potentially covering its marginal costs. If NECs are auctioned above $\$75/t_{CO_2}$, it is more profitable to run a dedicated oxy-BECCS plant than a co-firing CCS plant. The extra income brought by auctioning NECS also compensates for the efficiency drop associated with firing biomass instead of coal.

BECCS has the potential to offset 18 Mt/yr of industrial CO_2 emissions in the UK by auctioning NECs between \$90 and \$135 per t_{CO_2}. Offsetting this amount of emissions can be performed by deploying 5 oxy-BECCS plants

with a net power rating of 500 MW, buying time for the development of new industrial processes, and allowing the avoidance of stranded assets for the industrial sector. Offsetting the global 9 Gt_{CO_2}/yr emitted from industrial sources would increase the required number of BECCS plants to 3000. This is close to the estimated 3400 projects that would be required if CCS was to be directly applied to each CO_2 source.[130]

We demonstrate that the global availability of sustainable biomass is sufficient to meet the fuel requirements for 3000 BECCS plant of 500 MW capacity. Furthermore, the capacity of the current fleet of existing coal-fired power plants is comparable to the proposed fleet of BECCS plant. Thus, there is an opportunity to re-commission this existing coal infrastructure into BECCS, potentially reducing costs. The number of projects required to offset the global industrial CO_2 emissions could be reduced if the net power rating of the BECCS plants were increased (*e.g.*, from 500 MW to 1 GW). This framework would become highly competitive for higher capacity plants due to the reduced number of projects required when CCS is applied directly to the source and by taking advantage of economies of scale.

Applying CCS directly to some sources, such as low-concentration of CO_2 in some industrial processes, can incur in costs up to $\$170/t_{CO_2}$.[37] Both high costs and the requirement of changing the process makes certain industrial sectors hard to decarbonise. Hence, the framework proposed herein can enable industrial decarbonisation which does not require changes in the process.

This strategy may allow subsidy-free electricity from BECCS to become cost-competitive in a deeply decarbonised electricity market in the period to

2050.[21, 23, 24] Dispatchable thermal power, which is of demonstrated value to the electricity system, can be simultaneously provided with negative emissions using BECCS.[21, 23, 24, 56] The potential to re-use existing infrastructure by re-commissioning unabated coal plants instead of decommissioning them using this approach is highly promising. This would prevent loss of jobs, potentially increasing them[30], reducing the costs of carbon-free electricity, and promote industrial decarbonisation. Beyond 2050, a net carbon negative system is likely required.[21, 56] The successful re-commissioning of coal-fired plants to BECCS will most likely develop CCS technology to levels where it becomes attractive for adoption in some industrial sectors. After this point, BECCS plants can effectively remove atmospheric CO_2 and safely store it underground, thus setting the path towards achieving the 1.5 °C target.

Conflicts of interest

There are no conflicts to declare.

Acknowledgements

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Appendix A. Air separation unit

The air separation unit (ASU) was simulated as a double-column design using the assumptions[90, 137, 138] described in Table A.5, designed to provide oxygen at 97 mol% purity.

Inlet air passes through a filter to remove any particulate matter (not simulated) and is compressed in the main air compressor (MAC) to operating pressures. This stream and is then stripped of CO_2, water vapour, and other hydrocarbons using molecular sieve absorbers (not simulated). Firstly, this prevents the formation and build-up of ice in the main heat exchanger (MHX) and secondly, build-up of hydrocarbons in the distillation columns. Part of this stream is sent to a booster compressor before being sent to the MHX, where both compressed air streams are cooled against the cold products.

Part of the stream discharged by the booster compressor is extracted halfway from the MHX and expanded inside the turbine that drives the booster compressor. This air stream is then sent to the low pressure (LP) column along with the remainder stream from the booster compressor, which is expanded keep the column refrigerated. The remainder of cooled air is sent to the high pressure (HP) column where O_2 is pre-separated before being sent to the LP column for further separation. Both columns are integrated via a condenser/reboiler where condensing N_2 from the top of the HP column boils liquid O_2 at the LP column's sump. A stream with the required O_2 amount is produced this way from the bottom of the LP column, whilst a waste N_2 stream is produced at the top.

Table A.5: Operating conditions of the ASU simulated in this work, following Cabral and Mac Dowell [90]

Parameter	**Unit**	**Value**
Inlet air temperature	°C	10
Inlet air pressure	bar	1.01
Air composition		
N_2	mol%	78
O_2	mol%	20
Ar	mol%	1
MAC compression ratio		2.04
MAC adiabatic efficiency	%	90
Intercoolers outlet temperature	°C	28
Air sent to booster compressor	%	25
Air sent to expander	%	9
Expander outlet pressure	bar	1.06
HP column pressure	bar	4.1
CO_2 in bottom of HP column	mol%	39
LP column pressure	bar	1.1

Appendix B. Power plant

The O_2 stream from the ASU is mixed with recycled flue gas from the power plant obtaining an oxidant with 30% O_2. An excess amount of this oxidant is provided to obtain 3% O_2 in the flue gas after burning the fuel.[92, 121] The power-plant is an ultra-supercritical plant operating at a superheat/reheat conditions of 300/70 bar and 600/620 °C under the assumptions described in Table B.6.

Table B.6: Operating conditions of the power plant simulated in this work, according to Cabral and Mac Dowell [90]

Parameter	**Unit**	**Value**
Feedwater temperature	°C	300
Superheated steam temperature	°C	600
Reheated steam temperature	°C	620
Superheated steam pressure	bar	300
Reheated steam pressure	bar	70
Amount of ash in coal	wt%	30
Fly ash in total ash	wt%	75
Adiabatic efficiency of compressors	%	85
Adiabatic efficiency of turbines	%	90

The process starts with the fuel being milled by dedicated mills, modelled according to Williams et al. [115], assuming no pressure drop and an average

temperature increase of 1 °C[8].[139]

Power required to grind fuel

The specific work to grind fuel particles (W_{sp}, in kWh/t) is first calculated according to equation B.1.

$$W_{sp} = 10 \times BWI \left(\frac{1}{\sqrt{P_{80}}} - \frac{1}{\sqrt{F_{80}}} \right) \tag{B.1}$$

Where F_{80} and P_{80} (μm) is the particle size where 80% passing size of the feedstock and product, respectively, and are fuel specific (Table 2). The Bond work index (BWI, in kWh/t) reflects the material's resistance to milling and is calculated using equation B.2.

$$BWI = \frac{44.5}{10 P_1^{0.23} G^{0.82} \left(\frac{1}{\sqrt{P_{80}}} - \frac{1}{\sqrt{F_{80}}} \right)} \tag{B.2}$$

Where P_1 is the closing sieve size, here taken as 90 μm[90], and G is the grindability of feedstock (g/rev). The number of mills required for this operation was determined by assuming a maximum flow of 110 t/h[140] as an aid for estimating the equipment cost.

Simulation of the combustion process

Ground fuel is then combusted with the mixture of oxidant and recycled flue gas, where complete fuel combustion to CO_2, H_2O, SO_2, and N_2 was

[8]Note that temperature increase from individual particles is a function of particle size discharged from the mill, where the smallest particles could rise above 100 °C, whilst the largest particles less than 0.5 °C

assumed. First, the stoichiometric amount of oxygen required for complete combustion was determined.

$$CH_xN_yS_zO_w + \alpha\left(O_2 + \frac{y_{N_2}^{ox}}{y_{O_2}^{ox}}N_2 + \frac{y_{Ar}^{ox}}{y_{O_2}^{ox}}Ar\right) \longrightarrow CO_2 + \frac{x}{2}H_2O + zSO_2 + \left(\frac{y_{N_2}^{ox}}{y_{O_2}^{ox}}\alpha + \frac{y}{2}\right)N_2 + \left(\frac{y_{Ar}^{ox}}{y_{O_2}^{ox}}\alpha\right)Ar$$

Where α is the molar stoichiometric amount of oxygen (Equation B.3).

$$\alpha = 1 + \frac{x}{4} + z - \frac{w}{2} \tag{B.3}$$

This allows us to compute the stoichiometric oxidant/fuel mass ratio (Equation B.4)

$$\left(\frac{m_{ox}}{m_f}\right)_s = \frac{\alpha\left(MW_{\mathrm{O_2}} + \frac{y_{N_2}^{ox}}{y_{O_2}^{ox}}MW_{\mathrm{N_2}} + \frac{y_{Ar}^{ox}}{y_{O_2}^{ox}}MW_{\mathrm{Ar}}\right)}{m_f} \tag{B.4}$$

Where m_{ox} is the oxidant mass flow (kg/s), m_f is the fuel mass flow (kg/s), and MW_i is the molecular weight of component i (kg/kmol).

The real/stoichiometric ratio (λ) is then defined (Equation B.5) to determine the actual flue gas composition.

$$\lambda = \frac{m_{ox}/m_f}{\left(m_{ox}/m_f\right)_s} \tag{B.5}$$

This excess oxidant changes the flue gas composition according to the following reaction.

$$CH_xN_yS_zO_w + \alpha\lambda\left(O_2 + \frac{y^{ox}_{N_2}}{y^{ox}_{O_2}}N_2 + \frac{y^{ox}_{Ar}}{y^{ox}_{O_2}}Ar\right) \longrightarrow$$
$$CO_2 + \frac{x}{2}H_2O + \alpha(\lambda - 1)O_2 + zSO_2 +$$
$$\left(\frac{y^{ox}_{N_2}}{y^{ox}_{O_2}}\alpha\lambda + \frac{y}{2}\right)N_2 + \left(\frac{y^{ox}_{Ar}}{y^{ox}_{O_2}}\alpha\lambda\right)Ar$$

NO_2 and NO formation was then included according to Nakata *et al.*'s equation, because it only considers fuel NOx[141], assuming parallel flow burners (Equation B.6).

$$V_{NO_x} = N_{fuel}\frac{V_0}{MW_N}\frac{10^4}{V^{dry}_{FG}}\left(4.89\frac{FR}{N_{fuel}} + 4.57\right) \qquad \text{(B.6)}$$

Where V_{NO_x} is the amount of NOx in the flue gas (ppm), N_{fuel} is the nitrogen content in the fuel ($wt\%_{ar}$), MW_N is the molecular weight of atomic nitrogen (kg/kmol), V_0 is the ideal gas volume (22.4 m^3/kmol at STP), and V^{dry}_{FG} is the flue gas volume per kg of raw fuel (m^3/kg at STP).

The adiabatic flame temperature was then determined from the combustion products by calculating the enthalpy of reaction using Peng-Robinson equation of state through Multiflash.

Hot flue gas leaves the furnace and enters the boiler section where it increases feedwater temperature through a series of heat exchangers. The assumptions for heat transfer coefficient (U), feedwater outlet temperature (T_{out}) and pressure drop (Δp) are in Table B.7.

Hot steam from the boiler is sent to the turbine island where it generates electricity by expanding inside the high pressure (HP), intermediate pressure (IP), and low pressure (LP) turbines. A number of bleeds are taken from

Table B.7: Operating conditions of the boiler simulated in this work, according to Cabral and Mac Dowell [90]

Heat exchanger	**U ($W/(m_2\ K)$)**	T_{out} (°C)	Δp **(bar)**
Evaporator	80	401	5
Radiant superheater	50	500	5
Superheater 1	50	450	5
Superheater 2	50	600	4
Reheater 1	50	450	0.9
Reheater 2	50	620	3
Economiser	100	399	5

each turbine (Table B.8) to pre-heat cold feedwater before being recycled to the boiler at certain pressure ratios.

Warm flue gas leaving the boiler cools to 255 °C through a regenerative heat exchanger where it pre-heats recycled flue gas to increase combustion efficiency. This stream is cooled against feedwater temperature in another heat exchanger to just above acid dew point, guaranteeing safe operation of the baghouse filters.[84, 87] Flue gas leaving the regenerative heat exchanger is separated into two streams, where 52 wt% is recycled as the secondary recycle and then sent to the furnace after passing through a baghouse filter. The remainder of the flue gas also goes through a baghouse filter to remove fly ash and then cooled down to 25 °C before 27 wt% being used as the primary recycle and the rest sent to the GPU.

Table B.8: Operating conditions of the turbines simulated in this work, according to Cabral and Mac Dowell [90]

Turbine	**bleed no**	$\mathbf{w_n}$ (%)	**Pressure ratio** ($\frac{p_{out}^{bleed}}{p_{in}^{turbine}}$)
HP	1	9.30	0.25
IP	1	7.45	0.69
	2	5.2	0.36
	3	5.2	0.2
	4	5.8	0.1
LP	1	9.6	0.4
	2	6.2	0.13
	3	4.64	0.05

Appendix C. Gas processing unit

The gas processing unit (GPU) has a distillation column to obtain high purity CO_2 and keep O_2 levels below specification limits.[79] This unit was simulated with the assumptions presented in Table C.9.

Flue gas is compressed using a 3-staged compressor with intercooling and condensate removal before being sent to a dehydrator, where all water and SOx, as well as 90% NO_2 are assumed to be removed.[79]

Dehydrated flue gas is sent to a multiple-stage heat exchanger (MSHX) where it is cooled against products of the distillation column. This stream is then sent to the distillation column where CO_2 leaves from the bottom, and waste gas from the top.

The top gas is warmed in the MSHX, expanded in a flash unit where

Table C.9: Operating conditions of the GPU simulated in this work, according to Cabral and Mac Dowell [90]

Parameter	**Unit**	**Value**
Flue gas inlet pressure	bar	1.01
Flue gas inlet temperature	°C	25
LP comp, 1st stage compression ratio		9.9
LP comp, 2nd stage compression ratio		2
LP comp, 3rd stage compression ratio		1.4
LP comp intercooling temperature	°C	25
Recycle compressor discharge pressure	bar	28
Recycle cooler temperature	°C	-35
HP comp, 1st stage discharge pressure	bar	40
HP comp, 2nd stage discharge pressure	bar	68
HP comp intercooling temperature	°C	25
Pump discharge pressure	bar	110

795 the gas phase is used to cool incoming flue gas and then vented. Liquid from the bottom of the flash unit is further cooled in the MHX and recycled to the distillation column. High-purity CO_2 obtained from the bottom of the distillation column is used to cool incoming flue gas in the MSHX and compressed to pipeline pressure.

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