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Research Paper

# Blending biomass fuels for next-generation Power-BECCS plants

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ABSTRACT

To meet future resource requirements for the uptake of bioenergy with carbon capture and storage (BECCS) technologies to meet Net Zero targets, a range of biomass feedstocks are required to ensure the security of supply, utilise waste materials, and promote the circular economy. This study investigates the potential for blending forestry/agricultural residues and waste wood products with woody biomasses in combustion-based Power-BECCS, using a process model developed in Aspen Plus and validated against literature data. The base case assessment highlights the key performance indicators (KPIs) and energy penalty associated with CCS for next-generation BECCS plants. The results of a comparative study show the impact of blending various biomass species on plant KPIs. This research provides the basis for decision making on feedstock selection and optionality. Several alternate fuels produce similar KPIs to the base case, in some cases generating more net power (Fuels B, D, E, F, H, and I) or capturing more $CO_2$ (Fuels C and G). Overall, blending biomass fuels is a promising option to utilise alternate feedstocks, improve plant performance, and enhance the Carbon Dioxide Removal (CDR) potential.

## 1. Introduction

To achieve Net Zero by 2050, Carbon Dioxide Removal (CDR) technologies are required to ensure anthropogenic $CO_2$ emissions are removed from the atmosphere and durably stored [1]. The two most scalable CDR technologies are Direct Air Capture (DAC) and Bioenergy with Carbon Capture and Storage (BECCS). The additional benefit of BECCS is the low-carbon power generation and production of low-carbon chemicals or fuels [2]; hence, it is featured heavily in scenarios to reach net-zero $CO_2$ emissions [3,4]. Table 1 shows BECCS plants in construction and in early/advanced stages of deployment with capacities of < 50Mt $CO_2$/yr by 2030, falling short of the 190 Mt$CO_2$/yr required in the IEA's Net Zero Emissions (NZE) by 2050 scenario [5]. Waste-to-Energy (WtE) plants will form the bulk of the biogenic $CO_2$ capture from power generation, but the largest negative emissions contribution will come from Power-BECCS. The uptake of BECCS technologies needs to be accelerated in order to achieve Net Zero, this requires the utilisation of a wide range of biomass resources and responsible supply chain management, to ensure the security of low-carbon energy supply as well as minimise socio-environmental issues.

The legitimacy and ability of BECCS as a CDR technology was evaluated by DESNZ [6], which showed no significant barriers to permanent $CO_2$ removal when biomass supply chains are well-regulated and maintained. Next-generation Power-BECCS will have the capability to use 2nd generation (2G) biomass, developed to be non-competitive with food crops, which include lignocellulosic material from by-products, waste material, and dedicated feedstocks [7]. The choice of biomass feedstock is dependent on biomass type, physio-chemical properties, geographical location, supply chain infrastructure, transportation costs, storage costs, and seasonal and economic availability [8].

Typically, BECCS refers to bioenergy production; used directly for power and heat generation, as well as the conversion into solid/liquid/gaseous fuels, as depicted in Fig. 1. Carbon dioxide is absorbed from the atmosphere and converted into biogenic carbon. The $CO_2$ is released and subsequently captured once the biomass feedstock is converted into the end product. The conversion route (biological, chemical, thermal, and thermo-chemical) depends on the biomass feedstock [9]. Lignocellulosic biomass comprises of cellulose, hemicellulose, and lignin [10], and the chemical composition varies widely due to variations in biological diversity, moisture content, calorific value, and ash yield, classified based on the origin and source [11]. Ultimately, these variations result in different process efficiencies, emissions profiles, performance indicators, environmental concerns, and operational challenges.

Biomass boilers typically use pellets as a stable and consistent fuel form. Pelletisation condenses biomass resources into energy dense uniform cylindrical shapes through high pressure and temperature milling.

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A high-quality pellet should have high bulk density, high energy density, low moisture content, low ash content, and high durability [13]. When using blends the biomasses can be pre-mixed prior to pelletisation or mix the individual biomass pellets prior to thermochemical conversion [14]. Experimental studies have shown improved pellet characteristics for blending biomass pellets [15,16,17,18,19]. Combustion trials have shown blending can result in decreased levels of CO with minimal changes in combustion temperature [20,21,14]. The challenge with blending wood biomass with energy crops, forestry/agricultural residues, and waste wood products, is the high level of ash forming elements (Si, P, K, Ca, Mg, Al, and Cl). This may lead to an increase in particulate matter (PM) emissions and ash formation [14,22]. To the authors knowledge, there are no studies showing the impact of blended biomass feedstocks on BECCS plant performance.

There are limited process simulation studies for biomass combustion. Within the literature, the majority of work in simulators such as Aspen Plus, ChemCAD, Matlab, Fluent, OpenFOAM, and Gambit, focus on biomass gasification [23]. Ortiz et al. [24] modelled a subcritical biomass-fired power plant using Thermoflex®, a software used in industry for power plant optimisation. Thermoflex is a useful heat balance and plant design software, but it does not consider complex chemical reactions. Hence, the majority of the literature uses Aspen (Aspen Plus, Aspen Hysys, Aspen ONE, and Aspen Custom Modeller) to model thermochemical biomass processing [25].

The purpose of this study is to investigate blending alternative fuels for next-generation Power-BECCS, looking at energy crops, forestry/agricultural residues, and waste wood products, that have varying chemical compositions and physical properties. To this end, this works novel contributions are as follows:

- a novel process model for a Power-BECCS plant is developed to analyse the effect of blending biomasses, which uses combustion reaction kinetics and is validated using data from the literature.
- the model is applied to quantify key operating parameters (KOPs) and key process indicators (KPIs) for a next-generation Power-BECCS plant with and without $CO_2$ capture.
- the impact of blending different biomass feedstocks (forestry/agricultural residues, waste wood products, and dedicated energy crops) on a thermal basis.

Overall, the aim is to highlight the effect of biomass blending on boiler performance and flue gas characteristics, to highlight changes in impurities and effects on downstream CCS equipment.

## 2. Model development

Biomass combustion involves multiple stages, shown in Fig. 2, that need to be modelled in order to predict the thermal energy released and flue gas composition [26,27]. Moisture is removed from the fuel during the drying stage. Volatiles are released during pyrolysis by heating the feedstock without the presence of an oxidant. The remaining solid carbon is combusted (heterogeneous reactions), and the released volatile components react together (homogeneous reactions).

In order to model biomass combustion, the gasification reactions need to be considered (oxidation and reduction) to account for species generation and destruction within the combustion chamber. Once the reactions are included the equivalence ratio (ER) is adjusted to $> 0.35$ to simulate combustion [28]. For this study, the modelling is separated into three sections: biomass combustion, power generation, and CCS. To the authors knowledge, no studies have investigated modelling blended biomass feedstocks specifically for combustion modelling.

### 2.1. BECCS design

For BECCS, larger plants (>100MWth fuel input) are favourable due to improved efficiencies and economies of scale [29]. Large bioenergy power stations are estimated to have greater thermal power efficiencies (30 %–36 %) compared to smaller bioenergy plants (25 %–30 %) [30]. Within the literature, two main power cycles are investigated for BECCS: Steam Rankine Cycle (SRC) and Integrated Gasification with Combined Cycle (IGCC) [31]. This study focuses on thermo-chemical conversion through combustion; hence SRC is chosen for the power cycle [32]. Hot gases from combustion heat the steam to approximately 565℃ and 165 bar [33], which then passes through a cascade of steam turbines to produce power [34,35].

For the power plant, the most applicable $CO_2$ capture technology is post-combustion capture (PCC) using chemical solvents due to its maturity level [36]. The Global CCS Institute [37] highlighted State-of-the-Art CCS technologies in 2024, with many PCC technologies applicable to biomass flue gases and solvent based systems are the most mature. Drax Power Station (Selby, UK) piloted Mitsubishi Heavy Industries (MHI) KS-1™ and KS-21™ solvents [38]. Drax's Development Consent Order (DCO) for full-scale BECCS was awarded in January 2024 [39]. When operational it will make it the largest BECCS facility in the world with 8.0 Mtpa capacity across two units [12]. The Kansai Mitsubishi Carbon Dioxide Recovery process (KM-CDR Process®) has already been implemented commercially and has a lower energy penalty, estimated at 2.6 GJ/t$CO_2$ [40], significantly lower than traditional amine solvents (3.2–4 GJ/t$CO_2$) [36]. Once the $CO_2$ is captured it is

**Table 1**
Facilities for biomass-based power generation with CCS from Global CCS Institute [12].

| Facility | Technology | Country | Status | Operational | Capacity (Mtpa $CO_2$) |
|---|---|---|---|---|---|
| Hafslund Oslo Celsio WtE Plant | WtE | Norway | IC | 2024 | 0.4 |
| Amager Bakke WtE Plant | WtE | Denmark | AD | 2025 | 0.5 |
| Drax BECCS power plant | Power-BECCS | UK | AD | 2027 | 8 |
| Stockholm Exergi BECCS | CHP | Sweden | AD | 2027 | 0.8 |
| Clean Energy Systems Medota BECCS | Power-BECCS | USA | ED | 2025 | 0.3 |
| Redcar Energy Centre | WtE | UK | ED | 2025 | 0.4 |
| FREVAR WtE Plant | WtE | Norway | ED | 2026 | 0.06 |
| Kvitebjørn Varme Kvitebjørn WtE | WtE | Norway | ED | 2026 | 0.06 |
| SUEZ Tees Valley Energy Recovery Facility | WtE | UK | ED | 2026 | – |
| SUEZ WtE Plant | WtE | UK | ED | 2027 | 0.24 |
| Växjö Energi CHP Sandviksverket | CHP | Sweden | ED | 2027 | 0.18 |
| Encyclis Protos Energy Recovery Facility | WtE | UK | ED | – | 0.38 |
| Fidelis New Energy Cyclus Power Generation | Power-BECCS | USA | ED | – | 2 |
| FJernvarme Fyn Odense CHP plant | CHP | Denmark | ED | – | – |
| Fortum Waste Nyborg | WtE | Denmark | ED | – | – |
| Viridor Runcorn Waste Incineration | WtE | UK | ED | – | 0.9 |

Note: BECCS = bioenergy with carbon capture and storage, WtE = Waste-to-Energy, CHP = Combined Heat and Power, IC = In-construction, AD = Advanced development, ED = Early development.

conditioned and then transported via pipelines, due to the size of the plant and the quantity of $CO_2$. The conditioning train is based on compression and sub-critical liquefaction from Wilkes et al. [41].

### 2.2. Reaction kinetic model

Thermo-chemically converting solid fuels into heat and power in Aspen Plus requires the elemental decomposition of the feedstock into pure constituent components. There are many possible unit configurations applicable to biomass combustion. Studies have compared the different stoichiometric and non-stoichiometric approaches for gasification purposes [23,42,43], and showed improved estimation of flue gas composition using kinetic modelling. Hence, this study focusses on a kinetic approach to combustion modelling.

The BECCS model topology is shown in Fig. 3. Within Aspen, biomass is defined as a non-conventional solid. In order to simulate the combustion of biomass the feedstock (***FEED1)*** needs to be dried (**DRYER**) and converted into its constituent elements (**DECOMP**) using an rYield reactor. To include reaction kinetics, the combustion unit is separated into its core elements shown in Fig. 2. To simulate the pyrolysis section an rGibbs reactor (**PYRO**) converts the decomposed biomass into volatiles and solid carbon (char), based on Gibbs free energy minimisation, without any reaction chemistry or stoichiometry is included, [44]:

$$G_t = \sum_{i=1}^{N} n_i \mu_i \tag{1}$$

where $G_t$ is the total Gibbs free energy of the system, $N$ is the number of components, $n_i$ is the number of moles of component $i$, and $\mu$ is the chemical potential of component $i$. The char is combusted in an rPlug (**CHARCOMB**) reactor to thermally decompose the solid carbon, i.e., heterogenous reactions. Any remaining char and ash are removed using a separator (**ASH-SEP**). The volatiles are sent to the secondary combustion unit (**VOLCOMB**) where homogenous oxidation and reduction reactions occur. All reactions are considered stable. The air supply is separated into primary (**P-AIR**) supplied to the char chamber and secondary (**S-AIR**) supplied to the volatiles chamber, at a 60:40 split. Combustion reactions are described through the power law expression [45]:

$$r = kT^n e^{-\left(\frac{E}{RT}\right)} \prod_{i=1}^{N} C_i^{a_i} \tag{2}$$

where $r$ is the r reaction rate, $k$ is the pre-exponential factor,$T$ is the temperature, $n$ is the temperature exponent, $E$ is the activation energy, $R$ is the gas constant, $N$ is the number of components, $C_i$ is the concentration of the $i$ th component, and $a$ is the exponent of the $i$ th component. The relevant reactions and kinetic parameters are shown in Table 2, divided into oxidation and reduction type reactions. Table 2 also shows the heterogenous and homogenous reactions that will be used in CHARCOMB and VOLCOMB, respectively.

Once the combustion products are calculated, the hot flue gases pass through the heat-exchanger (**BOIL**) to heat pressurised water to power the high pressure (**HP-ST**), intermediate pressure (**IP-ST)**, and low pressure (**LP-ST**) steam turbines. The model calculates the work produced in each turbine at a set discharge pressure ($P_{out}$), isentropic efficiency ($\eta_i$), and mechanical efficiency ($\eta_m$).

The $CO_2$ in the flue gas is separated in **CO2-CAP**, using solvent based capture set at 95 % capture rate and requires 2.6 GJ/t$CO_2$. Steam required for the carbon capture stripper is extracted from the IP-ST and LP-ST connection. The quantity of steam required depends on the energy demand of the solvent and the relationship between $CO_2$ flowrate and regeneration steam demand is considered liner [46]. The $CO_2$ conditioning train first compresses (**CO2-COMP**) the stream to 66 bar before sub-critical liquefaction (**CO2-HX**) and $CO_2$ pumping (**CO2-PUMP**) to 153 bar.

The steady-state simulation assumes no tar or $NH_3$ formation. Ash is considered inert and does not take part in any reaction. The elements considered in this study include: $O_2$, $N_2$, $H_2O$, $CO_2$, $CO$, $H_2$, $CH_4$, $Cl_2$, $HCl$, $SO_2$, $SO_3$, $NO$, $NO_2$, and Ar. All reactors are isothermal with uniform pressure.

#### 2.2.1. Biomass blending comparative study

The fuel blends investigated in this study are based on different mixes of Wood chips (A), Soybean Husks (B), Corn Stover (C), Sorghum Bagasse (D), Miscanthus (E), Wheat Straw (F), Cotton Stalks (G), Waste Wood (H), and Grass Pellets (I). All of the feedstock physio-chemical characteristics are sourced from the Phyllis2 database from TNO [47], shown in Table 3.

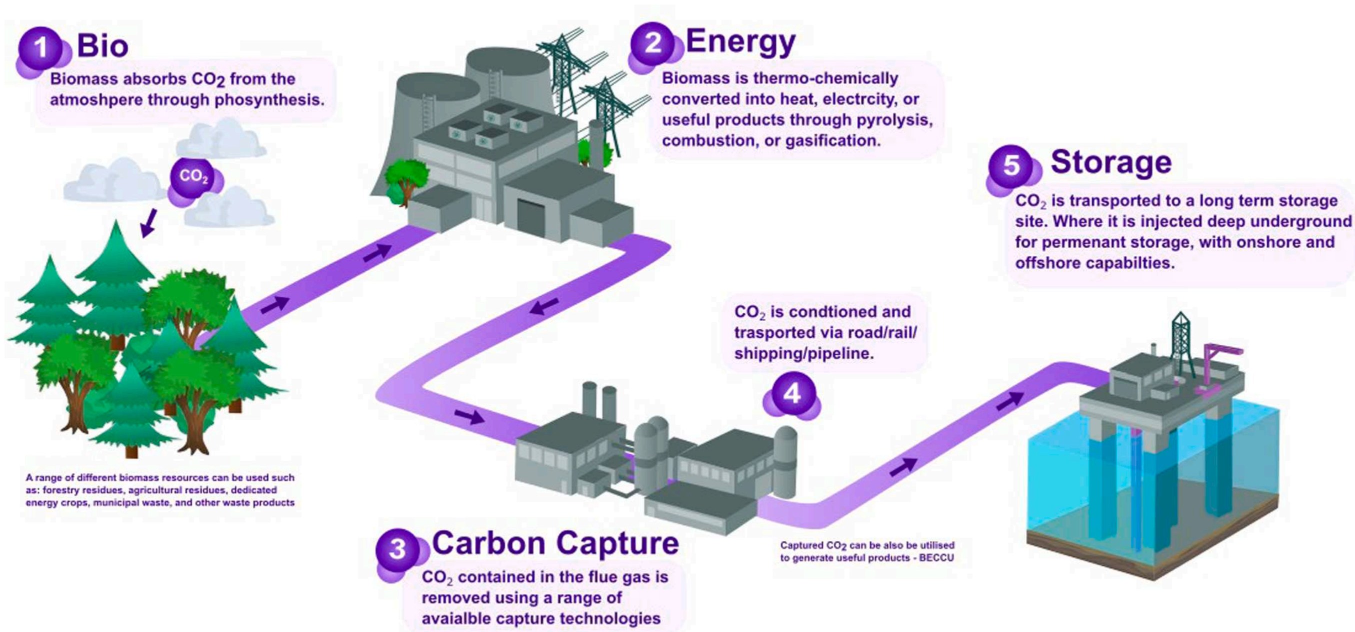


**Fig. 1.** Schematic representation of a Bioenergy with Carbon Capture and Storage (BECCS) value chain.

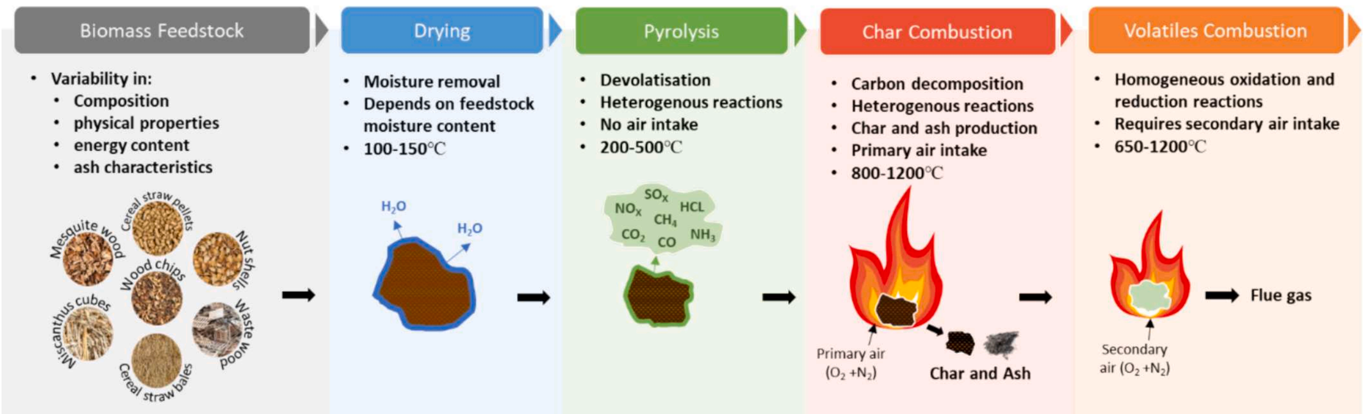


**Fig. 2.** Biomass combustion process showing drying, pyrolysis, char combustion, and volatiles combustion.

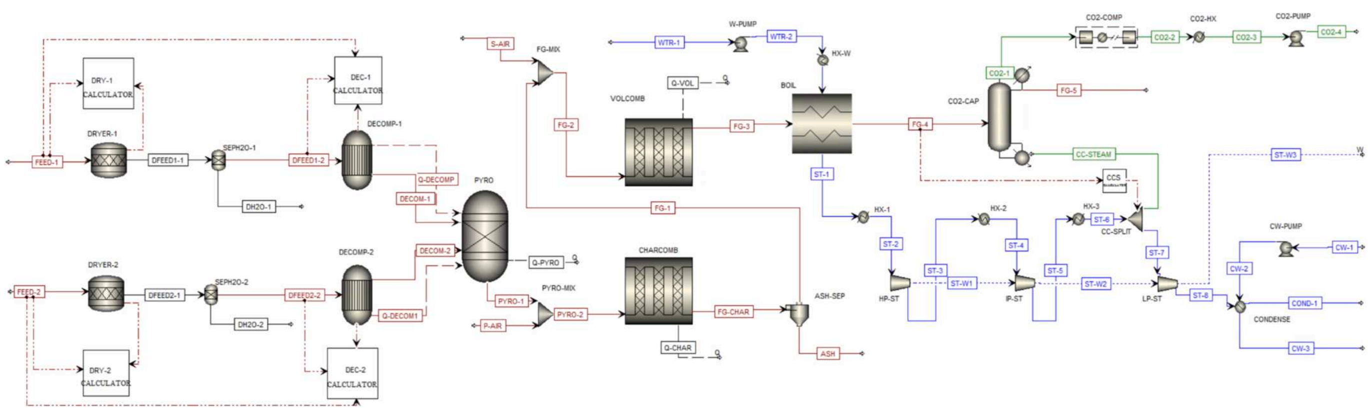

**Fig. 3.** Baseline BECCS power plant model topology developed in Aspen Plus. Biomass combustion, power generation, and $CO_2$ capture are shown in red, blue, and green, respectively.

**Table 2**
Heterogeneous and homogenous oxidation and reduction reaction kinetics for biomass combustion.

| Reaction # | | Reaction Name | Reaction | Kinetic Rate (kmol/m$^3$/s) | $A_i$ | $E_i$(kJ/kmol) | Ref |
|---|---|---|---|---|---|---|---|
| **Oxidation** | 1 | C oxidation | $1.25C + O_2 \rightarrow 0.5CO + 0.75CO_2$ | $r1 = 3.7 \times 10^{10} e^{\frac{-1.5\times10^5}{RT}}[O_2]$ | 3.7e + 10 | 1.5e + 05 | [48] |
| | 2 | CO oxidation | $CO + 0.5O_2 \rightarrow CO_2$ | $r1 = 1.78 \times 10^7 e^{\frac{-1.8\times10^5}{RT}}[CO][O_2]^{0.25}[H_2O]^{0.5}$ | 1.78e + 10 | 1.8e + 05 | [49] |
| | 3 | Methane oxidation | $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ | $r2 = 1.1 \times 10^9 e^{\frac{-2.03\times10^5}{RT}}[CH_4]^{-0.3}[O_2]^{1.3}$ | 1.1e + 09 | 2.03e + 05 | [50] |
| | 4 | $H_2$ oxidation | $H_2 + 0.5O_2 \rightarrow H_2O$ | $r3 = 2.20 \times 10^9 e^{\frac{-1.09\times10^4}{RT}}[H_2][O_2]$ | 2.20e + 09 | 1.09e + 04 | [50] |
| **Reduction** | 5 | Water gas | $C + H_2O \rightarrow CO + H_2$ | $r4 = 8.0 \times 10^{-3} e^{\frac{-4.99\times10^4}{RT}}[C][H_2O]$ | 8.0e-03 | 4.99e + 04 | [49] |
| | 6 | Boudouard | $C + CO_2 \rightarrow 2CO$ | $r5 = 1.05 \times 10^{13} e^{\frac{-1.35\times10^5}{RT}}[C]$ | 1.05e + 13 | 1.35e + 05 | [49] |
| | 7 | Methanation | $C + 2H_2 \rightarrow CH_4$ | $r6 = 1.0 \times 10^{-4} e^{\frac{-1.0363\times10^5}{RT}}[C][H_2O]$ | 1.0e-04 | 1.0363e + 05 | [48] |
| | 8 | Water-gas shift | $CO + H_2O \rightarrow CO_2 + H_2$ | $r7 = 1.35 \times 10^5 e^{\frac{-1.024\times10^5}{RT}}[CO][H_2O]$ | 1.35e + 05 | 1.024e + 05 | [51] |
| | 9 | $CO_2$ reduction | $CO_2 + H_2 \rightarrow CO + H_2O$ | $r5 = 1.2 \times 10^{10} e^{\frac{-3.18\times10^5}{RT}}[CO_2][H_2]^{0.5}$ | 1.2e + 10 | 3.18e + 05 | [51] |
| | 10 | Methane reformation | $CH_4 + H_2O \rightarrow CO + 3H_2$ | $r6 = 3.0 \times 10^{13} e^{\frac{-1.25\times10^5}{RT}}[CH_4][H_2O]^{0.5}$ | 3.0e + 13 | 1.25e + 05 | [49] |

The baseline feedstock (Fuel A) is mixed with varying degrees of the other feedstocks (Fuel B, C, D, etc…) up to 70/30 blends. Each biomass feedstock requires individual decomposition into constituent elements and to account for converting the ultimate analysis to a wet basis. The feeds (**FEED-1** and **FEED-2**) are dried at (**DRYER-1** and **DRYER-2**) before decomposition (**DECOMP-1** and **DECOMP-2).** For blended biomasses the physical properties changes but the composition elements (ash and water) are a balance between the biomass species. It is worth noting, the model does not take into consideration the physio-mechanical properties of the feedstock it only considers thermo-chemical conversion, i.e., the heat generation and species production.

In Aspen process models, calculator blocks are used to override unit operations and allow for in-built calculations of specific process variables. In this study, three calculator blocks are used for drying (**DRY-1** and **DRY-2**), chemical decomposition (**DEC-1** and **DEC-2**), and $CO_2$ capture (**CCS**). The dryer and decomposition blocks are shown in Fig. 3. Within DRY-1 and DRY-2 the conversion factor for moisture removal is based on the moisture content (proximate analysis) in the individual fuel

**Table 3**
Fuel composition and energy content for each feedstock from Phyllis2 [47].

| Type | | Wood Chips | Soybean Husks | Corn Stover | Sorghum Bagasse | Miscanthus | Wheat Straw | Cotton Stalks | Waste Wood | Grass Pellets |
|---|---|---|---|---|---|---|---|---|---|---|
| **ID** | | A | B | C | D | E | F | G | H | I |
| **Phyllis ID** | | 280 | 1916 | 704 | 1401 | 1744 | 459 | 2916 | 2748 | 2732 |
| **Proximate Analysis** | | | | | | | | | | |
| Total Moisture | % (a.r.) | 48.3 | 6.3 | 6.06 | 10.66 | 8.4 | 15.1 | 15 | 8.4 | 11.4 |
| Fixed Carbon | % (a.r.) | 8.13 | 71.12 | 13.23 | 16.52 | 5.1 | 14.98 | 19.25 | 18.13 | 62.91 |
| Volatile Matter | % (a.r.) | 42.83 | 17.8 | 75.96 | 65.58 | 84 | 62.32 | 63.07 | 69.83 | 14.97 |
| Ash | % (a.r.) | 0.74 | 4.78 | 4.75 | 7.24 | 2.5 | 7.6 | 2.68 | 3.64 | 10.72 |
| **Ultimate Analysis** | | | | | | | | | | |
| Carbon | % (a.r.) | 0.74 | 4.78 | 4.75 | 7.24 | 2.5 | 7.6 | 2.68 | 3.64 | 10.72 |
| Chlorine | % (a.r.) | 25.49 | 40.37 | 43.98 | 35.25 | 44.24 | 37.29 | 40.44 | 43.84 | 39.07 |
| Sulphur | % (a.r.) | 3.12 | 5.96 | 5.39 | 6.71 | 5.4 | 4.69 | 5.07 | 7.87 | 4.96 |
| Nitrogen | % (a.r.) | 0.09 | 0.8 | 0.62 | 0.98 | 0.52 | 0.62 | 0.21 | 1.03 | 2.22 |
| Hydrogen | % (a.r.) | 0.03 | 0 | 0.25 | 0.54 | 0.18 | 0.22 | 0 | 0.9 | 0.0055 |
| Oxygen | % (a.r.) | 0.01 | 0.09 | 0.1 | 0.2 | 0.1 | 0.19 | 0.1 | 0.01 | 0.41 |
| **Calorific value** | | | | | | | | | | |
| CV Gross | MJ/Kg | 10.06 | 16.48 | 17 | 15.99 | 17.69 | 14.99 | 13.5 | 17.77 | 16.45 |
| CV Net | MJ/Kg | 8.2 | 15.01 | 15.68 | 14.26 | 16.3 | 13.6 | 12.03 | 15.85 | 15.09 |

from FEED-1 or FEED-2. In DEC-1 and DEC-2, the new dry value of the ultimate analysis is calculated, and the resulting value is used to calculate the yield of the decomposition unit. Resulting in the chemical decomposition of the individual feedstocks.

The CCS calculator block, shown in Fig. 3**,** assigns the split ratio for the **CC-SPLIT** unit based on the incoming $CO_2$ flowrate to the **CO2-CAP** absorber. The ratio is based on capture technology, which requires 2.6 GJ/t$CO_2$ of steam at 120℃. As previously mentioned, the relationship between the steam flowrate and $CO_2$ flowrate is linear, hence it changes depending on the feedstock characteristics and the amount of $CO_2$ generated.

## 3. Results

Included in the results section is the model validation to discern the fidelity of the kinetic model. The base case results showcase the KOPs and KPIs for a next-generation Power-BECCS plant. Finally, the comparative study highlights challenges and opportunities associated with blending a variety of biomass resources, identifying potential alternate feedstocks to improve plant performance. Whereby, ‘alternate’ refers to biogenic resources other than conventional wood chips/pellets.

### *3.1. Model validation*

Finding suitable combustion data in the literature is challenging; the majority of studies highlighting emissions profiles for biomass focus on co-firing with coal or gasification technologies. Glushkov et al. [52] showed gas composition from biomass combustion and pyrolysis, highlighting emissions of $CO_2$, CO and $NO_X$ for leaves, straw, sawdust, and biomass blends. However, the experiment is conducted in an electric muffle furnace with a static feedstock, thus is not applicable to validate the current model. There are limited studies within the literature showcasing the performance of pure biomass combustion.

As this study investigates the combustion of dual input feedstocks, the model validation is based on case 2.1 from IEAGHG [53] which showed co-fired coal and biomass combustion performance. The feedstock characteristics are shown in Table 4. The process converts 300,600 kg/hr of bituminous coal and 86,400 kg/hr of wood chips into 810.9 MWe net power output. The flue gas flowrates and compositions in the IEAGHG and kinetic model is shown in Fig. 4 and Fig. 5, respectively.

Using the steam cycle characteristics from [53], the kinetic process model calculates the net power output to be 818.63 MWe, 0.95 % higher than the IEAGHG results. The process model does not take into account additional auxiliary power demand from solids handling, hence the lower energy demand and higher net power output. Overall, this demonstrates that the model closely aligns with the IEAGHG results and can effectively manage multiple feedstock streams, accurately calculating comparable flue gas compositions and key process indicators.

### *3.2. Base case*

The base case for the BECCS plant is based on 375,000 kg/hr of Wood Chips, the composition is shown in Table 3. The KOPs and stream

**Table 4**
Coal and biomass feedstock characteristics [53].

| Feedstock | Coal | Biomass |
|---|---|---|
| Moisture a.r. | 9.5 | 50 |
| Ash a.r. | 12.2 | 1 |
| Ultimate Analysis (wt.%) | | |
| Carbon | 64.6 | 25.0 |
| Hydrogen | 4.38 | 2.7 |
| Nitrogen | 1.41 | 0.15 |
| Chlorine | 0.03 | 0.01 |
| Sulphur | 0.86 | 0.03 |
| Oxygen | 7.02 | 21.1 |
| HHV (MJ/kg) | 27.06 | – |
| LHV (MJ/kg) | 25.87 | 7.3 |

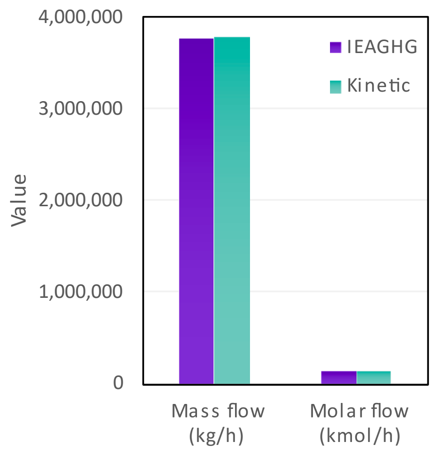


**Fig. 4.** Flue gas flowrate comparison between IEAGHG [53] and the kinetic model.

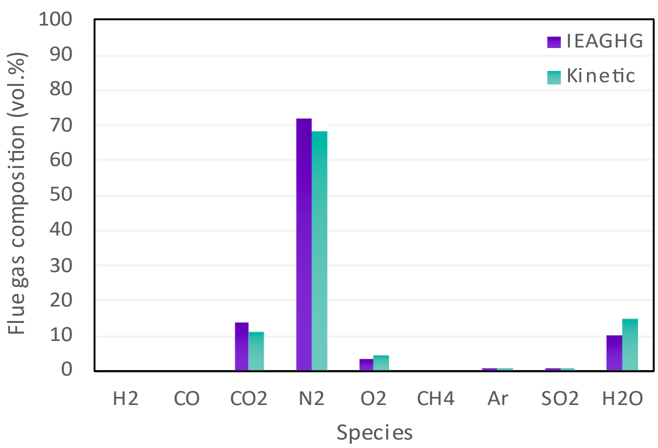


**Fig. 5.** Flue gas composition comparison between IEAGHG [53] and the kinetic model.

parameters are shown in Table 5 and Table 6, respectively. The air to fuel ratio is 3.9, within the range (2.92–5.12) tested by Kažimírová and Opáth [54]. Thomas et al. [55] carried out small-scale combustion tests on a 25 kW wood pellet biomass boiler, highlighting the average efficiency was 77 % net or 70 % gross; hence for this study the efficiency is set at 70 %, which is also within the range (63–81 %) tested by Kažimírová and Opáth [54].

The next-generation BECCS plant KPIs are shown in Table 7 and Fig. 6, the results also show a case without CCS. Both plants use 1,048 MW (HHV) of biomass input, without CCS the plant produces 397 MW of energy (gross). Including CCS decreased the gross energy output to 350 MW, due to steam provided for solvent regeneration, decreasing the flow

**Table 6**
BECCS power plant stream parameters.

| Stream | Parameter | Value |
|---|---|---|
| **WBIOMASS** | Flowrate (kg/hr) | 375,000 |
| | Temperature (°C) | 40 |
| | Pressure (bar) | 1 |
| **P-AIR** | Flowrate (kg/hr) | 877,487 |
| | Temperature (°C) | 260 |
| | Pressure (bar) | 1 |
| **S-AIR** | Flowrate (kg/hr) | 585,023 |
| | Temperature (°C) | 260 |
| | Pressure (bar) | 1 |
| **WTR-1** | Flowrate (kg/hr) | 1,326,430 |
| | Temperature (°C) | 30 |
| | Pressure (bar) | 1 |
| **CW-1** | Flowrate (kg/hr) | 28,000,000 |
| | Temperature (°C) | 15 |
| | Pressure (bar) | 1 |

**Table 7**
BECCS power plant key performance indicators with and without CCS.

| Parameter | Unit | Without CCS | With CCS |
|---|---|---|---|
| Biomass energy input (HHV) | MW | 1,048 | 1,048 |
| Biomass energy input (LLV) | MW | 854 | 854 |
| Gross electrical output | MW | 396 | 350 |
| W-PUMP power | MW | 11.5 | 11.5 |
| CW-PUMP power | MW | 1.26 | 0.93 |
| CO2-CAP | MW | 0 | 240 |
| CO2-COMP power | MW | 0 | 32.5 |
| CO2-PUMP power | MW | 0 | 1.3 |
| Total energy demand | MW | 12.8 | 46.3 |
| Net energy output | MW | 384 | 304 |
| Net electrical efficiency (HHV) | % | 36.7 | 29.0 |
| Net electrical efficiency (LLV) | % | 45.0 | 35.6 |
| COMBUST heat duty | MW | 609 | 609 |
| BOILER exchange | MW | 428 | 428 |
| Boiler efficiency | % | 70 | 70 |
| $CO_2$ input | t/hr | 349 | 349 |
| $CO_2$ captured | t/hr | 0 | 332 |
| $CO_2$ emissions | t/hr | 349 | 17 |
| $CO_2$ intensity | kg$CO_2$/MWh | 909 | 56 |

**Table 5**
BECCS power plant model KOPs.

| Unit | Parameter | Value | Unit | Parameter | Value |
|---|---|---|---|---|---|
| **DRYER** | Pressure (bar) | 1 | **CHARCOMB** | Pressure (bar) | 1 |
| | Temperature (°C) | 120 | | Temperature (°C) | 810 |
| **DECOMP** | Pressure (bar) | 1 | **VOLCOMB** | Pressure (bar) | 1 |
| | Temperature (°C) | 30 | | Temperature (°C) | 810 |
| **PYRO** | Pressure (bar) | 1 | **BOIL** | Outlet temperature (°C) | 147 |
| | Temperature (°C) | 500 | | Boiler efficiency (%) | 70 |
| **CO2-CAP** | Capture rate (%) | 90 | **W-PUMP** | Flowrate (kg/hr) | 1,326,400 |
| | $CO_2$ purity (%) | 100 | | Output pressure (bar) | 197 |
| **CO2-COMP** | $P_{out}$(bar) | 66 | **HP-ST** | $P_{out}$(bar) | 45.1 |
| | $\eta_i$(%) | 83 | | $\eta_i$(%) | 80 |
| | $\eta_m$(%) | 99 | | $\eta_m$(%) | 87.4 |
| **CO2-PUMP** | $P_{out}$(bar) | 153 | **IP-ST** | $P_{out}$(bar) | 6 |
| | $\eta_i$(%) | 85 | | $\eta_i$(%) | 80 |
| | $\eta_m$(%) | 98 | | $\eta_m$(%) | 92.2 |
| **CW-PUMP** | Flowrate (kg/hr) | 238,000 | **LP-ST** | $P_{out}$(bar) | 0.096 |
| | $P_{out}$(bar) | 2 | | $\eta_i$(%) | 80 |
| | $\eta_i$(%) | 85 | | $\eta_m$(%) | 91.9 |
| | $\eta_m$(%) | 98 | | | |

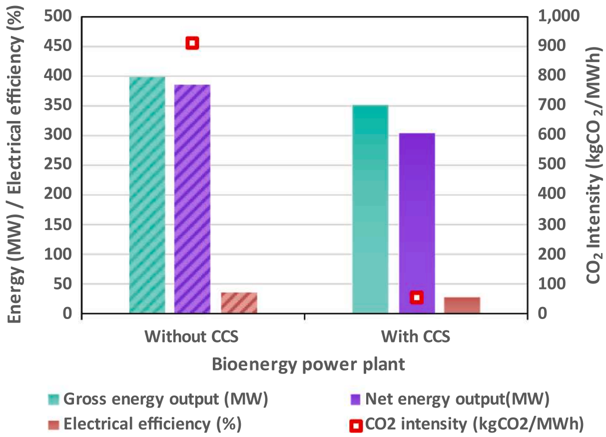


**Fig. 6.** Bioenergy plant key performance indicators with and without CCS.

through the LP-ST unit. Accounting for internal power consumption the net plant export is 384 MW without CCS and 304 MW with CCS, making the thermal efficiencies 37 % and 29 %, respectively (HHV basis). Comparable to the results from Ricardo Energy & Environment [36], which showed a BECCS plant with post-combustion amine absorption (90 % capture) with a gross capacity of 498 MWe (396 MWe Net) has a gross efficiency of 38.5 % (30.6 % Net). It is worth noting that mechanical power and electricity consumption for solid fuel handling and general parasitic energy demands are not accounted for in this study. Using MHI's KS-21™ solvent with an energy demand of 2.6 GJ/t$CO_2$, the BECCS plant power output decreases by 7.68 % but captures 332,417 kg/hr. Assuming 91 % capacity factor, this plant will capture 2.65 Mt$CO_2$/yr.

Fig. 7 shows a Sankey diagram of the energy flow through the system. The overall process is 29 % efficient due to losses from combustion, boiler heat-exchange, turbine power conversion, CCS, and auxiliary process losses. Significant losses are associated with the combustion and boiler elements of the plant; utilising alternate combustion (oxy-fuel) and boiler designs can improve the thermal efficiency. This design includes an integrated solvent-based $CO_2$ capture plant, but emerging capture technologies have shown lower energy requirements that would also improve the overall plant efficiency [40].

### 3.3. Fuel blending comparative study

The case studies are performed on a thermal basis to prevent modifying KOPs to account for additional thermal generation due to the higher energy content of the alternate fuels (see Table 3). The feedstock energy input is kept constant at 1,047,917 kW (HHV), using the feedstock blending mass flowrates shown in Fig. 8 and Supplementary Information Annex B. The mass flowrate for each case varies depending on the energy content of the alternate fuel. Fig. 8 shows results for two blended simulations, X1 (95 % A and 5 % X) and X6 (70 % A and 30 % X), to highlight the range of experiments conducted in this study.

Flue gas composition changes for 70:30 blend ratios for major and minor components are shown in Fig. 9 and Fig. 10, respectively. All of the cases, except Fuel D, show an increase in $CO_2$ concentration as there is less $H_2O$ in the flue gas due to the lower moisture content in the alternate fuels. However, the mass flowrate of $CO_2$ is lower in the alternate fuel blends, except Fuel A/C-6 (0.62 % higher) and Fuel A/G-6 (5.47 % higher); this is a result of multiple factors such as moisture content, ash content, calorific value, and variations in ultimate analysis.

The difficulty in comparing alternate fuels is the complex interaction of different thermo-chemical properties. All of the alternate fuels have a

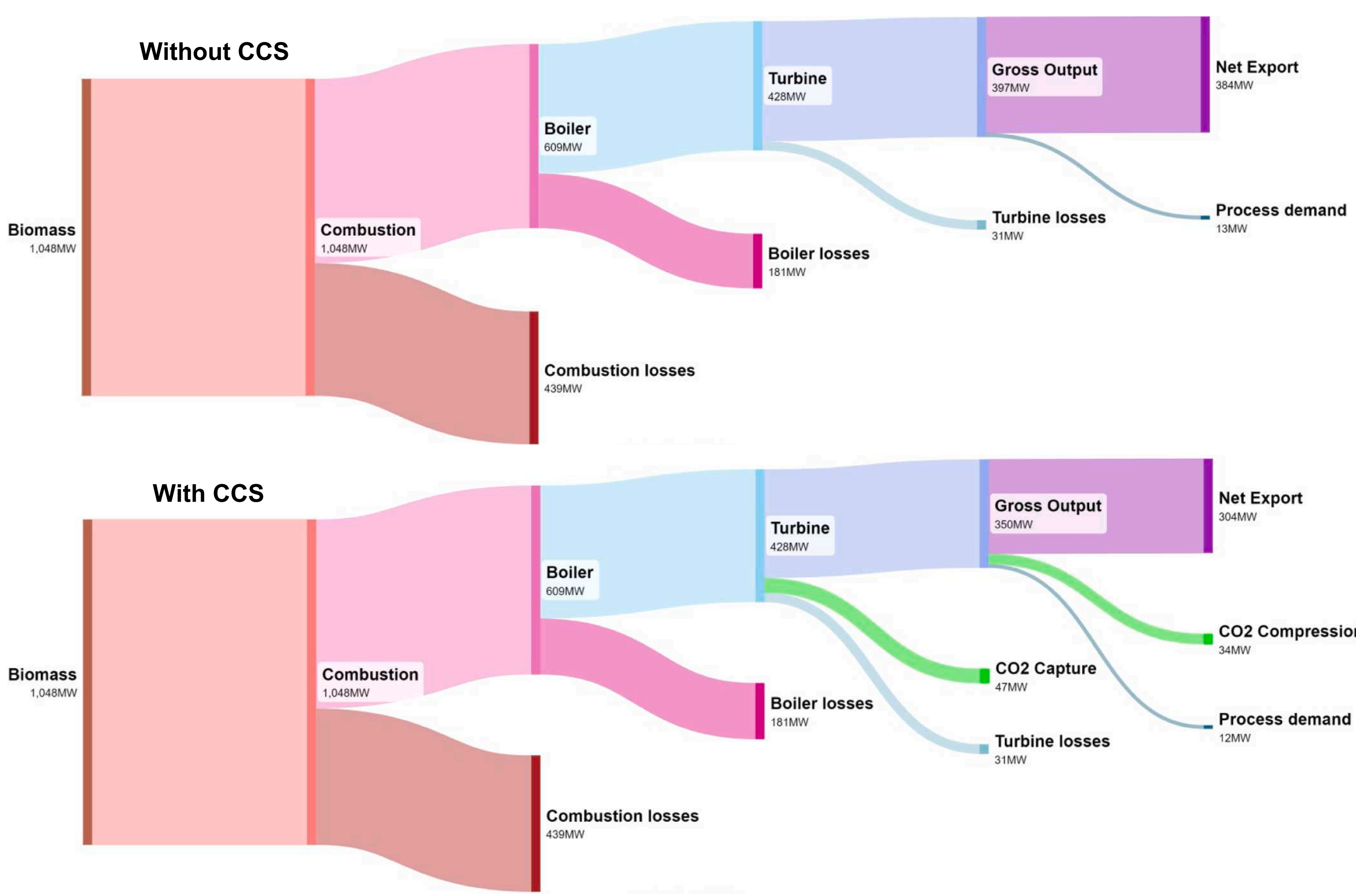


**Fig. 7.** Sankey diagram showing energy flow through the BECCS power plant, with and without CCS.

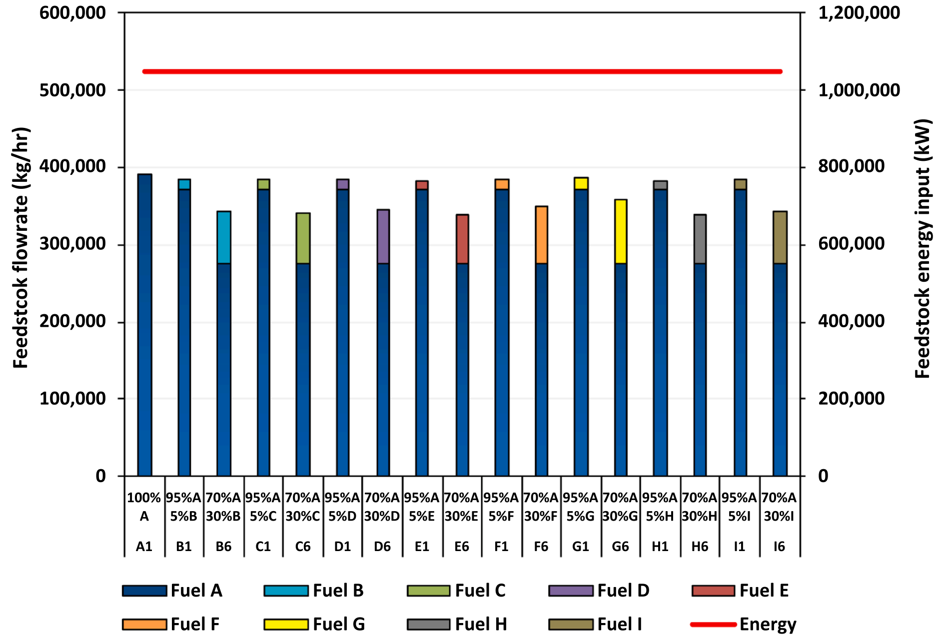


**Fig. 8.** Feedstock flowrate and energy input during each case study.

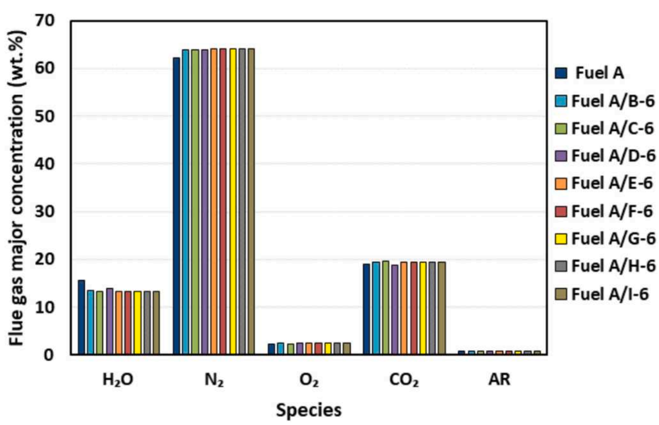


**Fig. 9.** Flue gas major component concentrations in the 70:30 fuels blends.

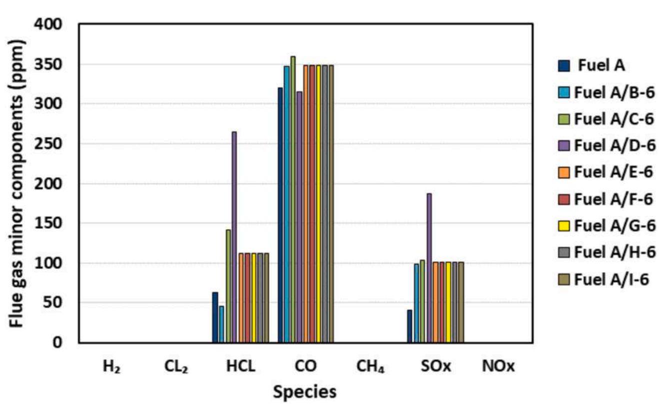


**Fig. 10.** Flue gas minor component concentrations for the 70:30 fuels blends.

higher carbon content in the ultimate analysis but have a lower carbon to oxygen ratio. Resulting in a small decrease in oxygen concentration. All of the alternate fuels have a higher ash content, which produces more ash and reduces the mass flowrate of flue gas resulting from combustion.

Furthermore, the low moisture content in the feedstock reduces the $H_2O$ concentration throughout the system, making the classification of alternate fuels based on flue gas composition challenging.

Another important factor is the cost of these feedstocks. The economic feasibility is dictated by specific geographic sourcing and requires a full supply chain analysis [56,57], which is beyond the scope of the current work.

Fuel D shows a 347 % increase in $SO_X$ emissions due to the high sulphur content in the feedstock, it also has a high chlorine content and thus produces 310 % more HCl when blending up to 70:30 on a thermal basis. Interestingly, it does not have the highest S (Fuel I) or Cl (Fuel H) content of the alternate fuels. The higher emissions concentrations are due to a combination of lower carbon content, high ash flowrate, high energy content, and lower $CO_2$ generation. The higher emissions of $SO_X$ and HCl for the alternate fuels are problematic and would require additional emissions cleaning technologies before venting the flue gas to the atmosphere. The results show no change in $H_2$, $Cl_2$, $CH_4$, and $NO_X$ emissions for all of the alternate fuel blends. A full breakdown of emissions for each case is shown in Supplementary Information Annex C.

The ash flowrate changes for all of the fuel blends are shown in Fig. 11. It is linked to the ash content in the feedstock as well as the

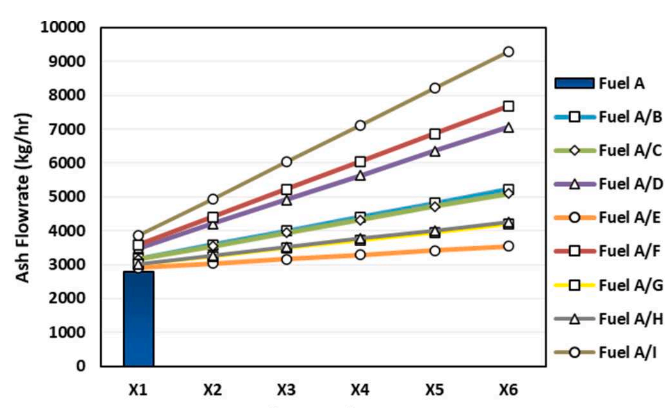


**Fig. 11.** Ash flowrate changes for each case study.

moisture and energy content. Fuel G has 6.7 % more ash than Fuel E but has 44 % higher moisture content and 31 % higher energy content, thus produces 15 % more ash overall in the 70:30 blend case (X6).

Blending biomass species for BECCS power generation is a multi-faceted issue, the complexities of thermal energy generation coupled with power cycle constraints makes the comparison of feedstocks challenging. For integrated BECCS power plants, the net power export (and process efficiency) is inversely linked with the quantity of $CO_2$ produced and subsequently captured, shown in Table 8. Increased $CO_2$ generation requires more steam for solvent regeneration, reducing the steam flowing into the final LP steam turbine and producing less power. It is worth noting, the gross power output of the plant remains constant; this is to highlight the different energy requirements of the different feedstocks. Fuel A/G has the largest decrease in net power export, 1.41 % lower than Fuel A, but capture 5.5 % more $CO_2$. Whereas, Fuel A/D has the largest increase in net power export, 0.25 % higher than Fuel A, but captures 0.9 % less $CO_2$. The majority of alternate fuels only fluctuate < 1 % compared to the baseline; hence, blending up to 70:30 ratio will not significantly change BECCS power plant KPIs. The results show that utilising alternate fuels can potentially generate more power export or promote enhanced $CO_2$ captured.

All of the alternate fuels have more energy available in the combustion units, shown in Fig. 12, and optimising the steam power cycle and boiler size can utilise this additional energy to generate more power. More energy is generated as the alternate fuels have a higher energy content and lower moisture content, leading to improved combustion performance. As the energy content of the alternate fuels is higher than the Fuel A (Wood Chips) and the feedstocks are blended on a thermal basis, each of the cases has a lower flue gas volumetric flowrate, leading to a decrease in boiler energy exchange and boiler efficiency. As an example – the boiler efficiency of Fuel A/G-6 is 66 % with 626,591 kW of combustion energy. Maintaining the boiler efficiency at 70 % requires altering the power cycle to use 10 % more steam, this will generate 338 MW net power output and is 11.4 % higher than original A/G-6 case. Hence, the alternate fuels can increase the quantity of $CO_2$ captured and stored, as well as increase the net power export through altering the power cycle.

**Table 8**
Key performance indicators for each of the case studies.

| Case | Net Export (kW) | Process efficiency (%) | $CO_2$ Captured (kg/hr) | $CO_2$ Captured ($MtCO_2$/yr) | $CO_2$ Intensity ($kgCO_2$/MWh) |
|---|---|---|---|---|---|
| Fuel A | 303,689 | 28.98 | 332,417 | 2.65 | 57.61 |
| Fuel A/B-6 | 304,434 | 29.05 | 329,352 | 2.63 | 56.94 |
| Fuel A/C-6 | 303,187 | 28.93 | 334,482 | 2.67 | 58.06 |
| Fuel A/D-6 | 306,817 | 29.28 | 319,548 | 2.55 | 54.82 |
| Fuel A/E-6 | 304,016 | 29.01 | 331,071 | 2.64 | 57.32 |
| Fuel A/F-6 | 304,104 | 29.02 | 330,710 | 2.64 | 57.24 |
| Fuel A/G-6 | 299,391 | 28.57 | 350,596 | 2.79 | 61.63 |
| Fuel A/H-6 | 304,397 | 29.05 | 329,502 | 2.63 | 56.97 |
| Fuel A/I-6 | 305,246 | 29.13 | 326,012 | 2.60 | 56.21 |

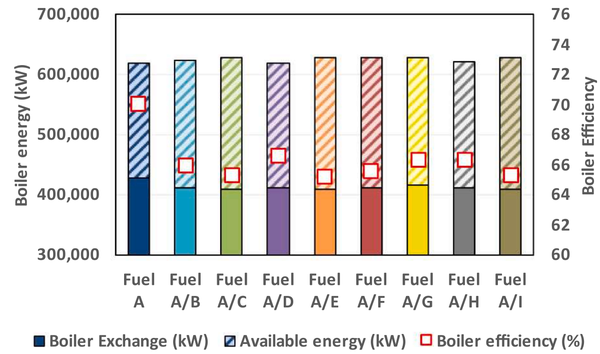


**Fig. 12.** Boiler efficiency and amount of available heat remaining in the boiler for the 70:30 fuels blends.

The key KPIs are plotted alongside one another in Fig. 13 to show the interaction between process variables. The BECCS facility is integrated, and the power export is directly linked with the $CO_2$ capture facility; hence, the $CO_2$ intensity is identical to the $CO_2$ captured and ranges between 54.8–61.6 kgCO2/MWh). It is clear from the figure that the more $CO_2$ that is produced the lower the power export; therefore, there is a trade-off between the sale of electricity and the CDR credits.

As such, the results indicate that blending alternate fuels with wood chips does not significantly alter BECCS plant KPIs. Furthermore, in most cases fuels B, D, E, F, H, and I can increase net power export, due to a lower CCS energy penalty, whereas, for G and C the high $CO_2$ production results in a decrease in net power export and a higher $CO_2$ intensity. For all of the fuel blends there is further potential for optimisation of the boiler and power cycle performance. Fuels C and G capture more $CO_2$, and if their processes are optimised, may produce more power in comparison to pure Wood Chips.

## 4. Conclusion

Bioenergy with Carbon Capture and Storage is a negative emissions technology capable of providing low-carbon sustainable power. Supply chains need to be well maintained and regulated to ensure the legitimacy of carbon removal claims. With the expected increase in installed BECCS capacity, required to achieve Net Zero, alternate biomass feedstocks will be required to meet sustainable fuel feedstock demands. To assess their efficacy, the impact of these alternate fuels on plant performance and emissions need to be ascertained. This study analyses the potential for blending waste material with conventional wood chips. Initially, two types of power plant models are validated and compared against one another to see the most applicable model type. For this study, the reaction kinetics model showed better fidelity and robustness in calculating flue gas emissions.

The base case model results showed a BECCS plant producing 304 MWe has an electrical efficiency of 29.0 % (HHV) and captures 2.65 $MtCO_2$/yr. Without CCS the bioenergy plant would produce 384 MWe with a process efficiency of 36.7 % (HHV); therefore, the CCS energy penalty is 7.68 % points.

Multitude of factors affect BECCS KPIs when using different feedstock blends. The alternate fuel KPIs are very similar to the base case and some show improved performance in terms of process efficiency and $CO_2$ intensity. However, in all cases the thermal efficiency of the boiler decreases with the addition of higher energy content fuel, indicating more power can be generated if the steam cycle and boiler operation is adjusted. The results have shown the use of alternate biomass fuels can help utilise waste material, strengthen the security of the feedstock supply, and capture more $CO_2$ (enhanced CDR potential). The choice of feedstock is highly dependent on the specific plant design; in certain cases the KOPs need to be altered to maintain plant KPIs. The case study evaluation has shown:

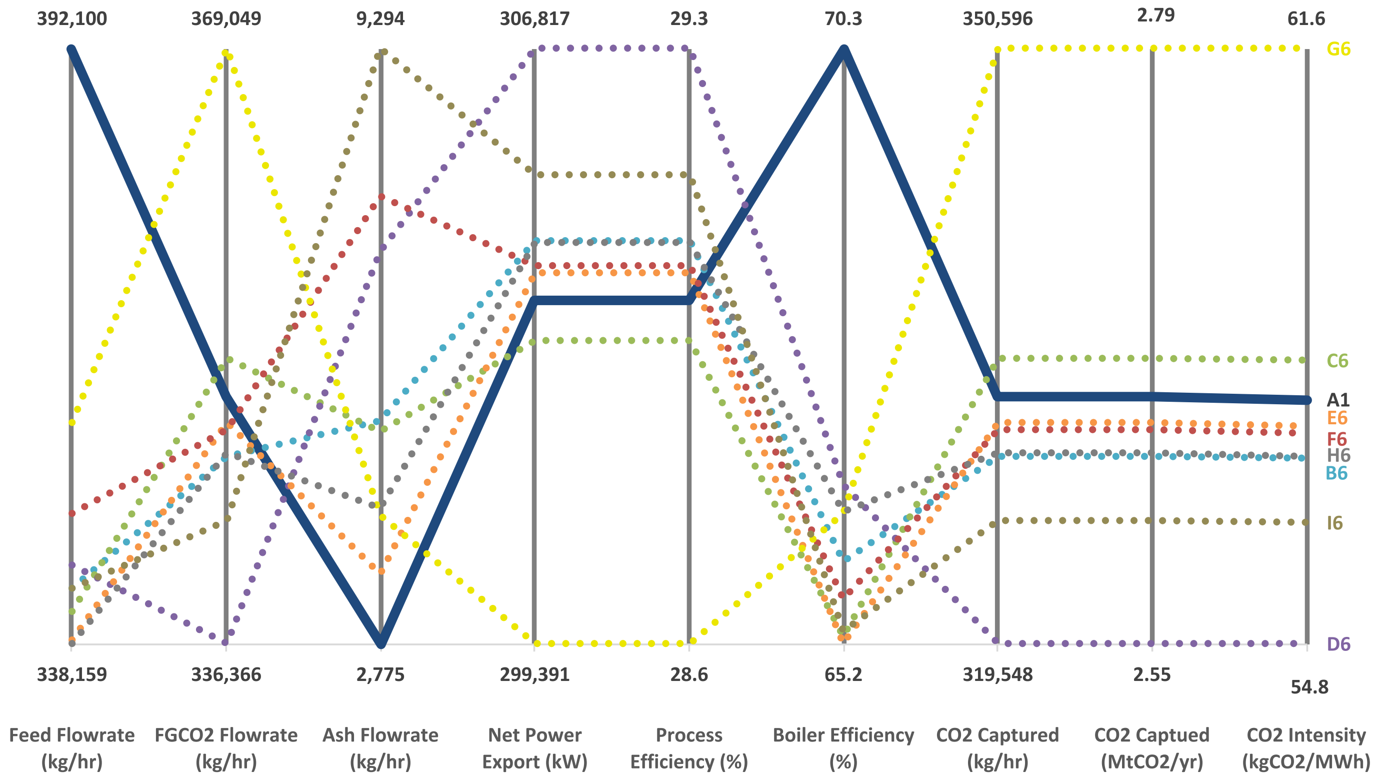


**Fig. 13.** Parallel plot for BECCS KPI comparison between each case study.

- High C/O ratio (with low ash and moisture content) will result in increased $CO_2$ production.
- High CCS energy penalties lead to decreased net power export and lower process efficiency.
- High sulphur content in the fuel will result in an increase in SOx emissions which would require flue gas desulphurisation, similarly with HCL emissions.
- All the alternate fuel blends have a lower boiler efficiency compared to pure wood chips due to the lower moisture content, higher energy content, decreased flue gas flowrate, and lower boiler heat exchange.
- Available heat remaining in the boiler fluid can be utilised to improve KPIs.

Energy crops, agricultural/forestry residues, or waste wood can be used to supplement conventional woody biomass feedstocks; however, the alternate fuels will have different operational challenges such as different fuel handing requirements, high ash forming components which lead to slagging and fouling, and increased emissions (other than $CO_2$) requiring abatement.

The current research is purely computational, and the reported values are estimates based on a validated process model using a specific feedstock and plant design. Future work should validate the current findings by performing combustion tests on alternate fuels and comparing the flue gas characteristics, to accurately assess the fidelity and robustness of the model. Future research should also focus on optimising a selection of alternate fuels and specific blending ratios, to ascertain the best achievable potential for each blend. Blending alternate fuels produces similar plant KPIs to pure wood chips, in some cases generating more power or more $CO_2$. As the two metrics are intrinsically linked to the integrated plant design, an economic study is required to investigate the balance between additional energy sales and carbon dioxide removal (CDR) credits.

## CRediT authorship contribution statement

**Mathew Dennis Wilkes:** Writing – original draft, Methodology, Investigation, Formal analysis, Conceptualization. **Erik Resendez:** Investigation, Formal analysis, Data curation. **Solomon Brown:** Writing – review & editing, Supervision, Resources, Project administration, Funding acquisition, Conceptualization.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enconman.2024.119287.

## Data availability

Data will be made available on request.

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