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LETTER

Inefficient power generation as an optimal route to negative emissions via BECCS?

Niall Mac Dowell[1,2,3] **and Mathilde Fajardy**[1,2]

1 Centre for Environmental Policy, Imperial College London, South Kensington, London SW7 1NA, United Kingdom
2 Centre for Process Systems Engineering, Imperial College London, South Kensington, London SW7 2AZ, United Kingdom
3 Author to whom any correspondence should be addressed.

E-mail: niall@imperial.ac.uk

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Abstract

Current ambitions to limit climate change to no more than 1.5 °C–2 °C by the end of the 21st century rely heavily on the availability of negative emissions technologies (NETs)—bioenergy with CO_2 capture and storage (BECCS) and direct air capture in particular. In this context, these NETs are providing a specific service by removing CO_2 from the atmosphere, and therefore investors would expect an appropriate risk-adjusted rate of return, varying as a function of the quantity of public money involved. Uniquely, BECCS facilities have the possibility to generate both low carbon power and remove CO_2 from the atmosphere, but in an energy system characterised by high penetration of intermittent renewable energy such as wind and solar power plants, the dispatch load factor of such BECCS facilities may be small relative to their capacity. This has the potential to significantly under utilise these assets for their primary purpose of removing CO_2 from the atmosphere. In this study, we present a techno-economic environmental evaluation of BECCS plants with a range of operating efficiencies, considering their full- and part-load operation relative to a national-scale annual CO_2 removal target. We find that in all cases, a lower capital cost, lower efficiency BECCS plant is superior to a higher cost, higher efficiency facility from both environmental and economic perspectives. We show that it may be preferable to operate the BECCS facility in base-load fashion, constantly removing CO_2 from the atmosphere and dispatching electricity on an as-needed basis. We show that the use of this 'spare capacity' to produce hydrogen for, e.g. injection to a natural gas system for the provision of low carbon heating can add to the overall environmental and economic benefit of such a system. The only point where this hypothesis appears to break down is where the CO_2 emissions associated with the biomass supply chain are sufficiently large so as to eliminate the service of CO_2 removal.

1. Introduction

In order to limit climate change to no more than 1.5 °C–2 °C by the end of the 21st century [1], it is generally accepted that the deployment of so-called 'negative emissions technologies' (NETs), i.e. technologies whose operation results in the net removal of CO_2 from the atmosphere, are key to achieving this goal [2]. There are several options typically proposed for NETs, including direct air capture (DAC) [3–5], mineral carbonation [6], aforestation [7], biological [8] or chemical [9] ocean fertilisation, soil carbon storage via modified agricultural practices [10], addition of biochar to soil [11] and bioenergy with CO_2 capture and storage [12–14]. Whilst each of these options are distinct, with individual trade-offs in terms of energy, cost, land space requirement, water requirement per unit CO_2 removed from the atmosphere [15, 16], BECCS is perhaps unique in that it has the potential to generate electricity whilst simultaneously removing CO_2 from the atmosphere [14].

It is important to recognise that the operators of a NET facility are providing a specific service—allowing the avoidance of the costs associated with the consequences of dangerous climate change. This is sometimes referred to as the 'social cost of carbon' [17]. Calculating a value of the social cost of carbon is possible [18], and whilst this is highly complex [19, 20], it does provide a backstop value for the provision of this service.

Noting that the challenge of removing CO_2 from the atmosphere is distinct to avoiding its emission in the first place [12, 21], it is reasonable to expect that an incentive scheme, through which the value associated with the provision of this service can accrue to the service providers, is likely to be vital in leveraging investment in this technology on a meaningful scale. Where public capital is used to finance such projects, an acceptable internal rate of return (IRR) would be on the order of 4%–6% and in the case of private capital, the IRR would be expected to be on the order of 10%–14%, if not more.

However, over the course of the 21st century, the composition of the global energy system is expected to change substantially and whilst the composition of regional energy systems will vary, a common characteristic of global energy system evolution is expected to be the extensive deployment of renewable energy generation, with intermittent renewable energy (iRE) sources such as wind and solar power often expected to account for the majority of this renewable energy capacity [22]. A key characteristic of iRE is that, owing to a lack of fuel costs, the marginal cost (MC) per MWh of electricity is relatively low. However, owing to its intermittent nature, it is well-known that iRE displaces thermal power generation, but not thermal power plant capacity [23], and as a consequence, the average load factor of those thermal power plants may well decrease to an average in the rage of 40%–60% in scenarios with substantial deployment of iRE[4] [24].

Moreover, in a liberalised electricity market, power plants with the lowest MC of electricity generation will, all else being equal, displace plants with higher costs, thus delivering the lowest electricity costs to the consumer. As a consequence this has driven power plant design towards increased efficiency of fuel conversion—greater power plant efficiency—leading to reduced fuel required and CO_2 produced per MWh of electricity generated. Thus, owing to potentially greater fuel costs, relatively low energy density of that fuel, the MC of a BECCS power plant will, in all likelihood, be appreciably greater than that of a fossil-fired thermal power plant, even with CO_2 capture and storage technology, and therefore, in a liberalised electricity market would normally have a reduced load factor relative to its low-carbon counterparts, e.g. nuclear or fossil-CCS power plants.

However, in order to maximise removal of CO_2 from the atmosphere, the BECCS plant would need to operate at a high load factor and burn as much biomass per year as possible. This implies a low efficiency at converting biomass into electricity, thus producing and capturing the maximum CO_2 per MWh (or per year) possible. Therefore, BECCS plants that are less efficient at converting biomass to electricity may be preferred from the perspective of removing the maximum amount of CO_2 from the atmosphere [25]. This leads to a seemingly paradoxical arrangement—an inefficient thermal power plant operating in baseload fashion in an energy system with substantial amounts of iRE[5]. Exploring this paradox and the associated trade-offs is the purpose of this paper. The remainder of this paper is laid out as follows; we first present the modelling approach and assumptions that were used in this study, we then present the results and conclude with a discussion and some perspectives for future work.

2. Techno-economic model of BECCS process

This section details the model developed and defines the scenarios which were evaluated in this study.

2.1. Scenario definition

Three distinct scenarios were considered in this study, and are described below.

Scenario 1 (Sc1) considers the BECCS plants to operate in response to a demand for electricity—what would be traditionally considered to be a load-following manner. They burn biomass to produce power in response to a market demand, and remove CO_2 from the atmosphere as a consequence.

Scenario 2 (Sc2) considers the BECCS plants to operate in a baseload fashion, constantly removing CO_2 from the atmosphere, but dispatching electricity only when there is a demand. When surplus electricity is generated, it is 'spilled'[6], and no payment is assumed. This is a relatively common response within energy systems with periods of oversupply [26]

Scenario 3 (Sc3) considers the BECCS plants to operate in a baseload fashion, constantly removing CO_2 from the atmosphere, but dispatching electricity only when there is a demand. When surplus electricity is generated, it is directed to an electrolysis plant to produce hydrogen which is, in turn, sold to provide a heating service. The value of this hydrogen is indexed off of current methane market values on a mass-based energy content. It is also conceivable that this H_2 could also be used as a transport fuel or as an industrial feedstock. However, for this study, we have focused solely on the power-to-gas model.

[4] This is the average capacity factor of the installed fleet of thermal power plants—specific capacity factors of individual plants have the potential to be much lower

[5] And possibly energy storage

[6] Also referred to as curtailment.

2.2. BECCS model

The purpose of this model is to calculate the net present value (NPV) and internal rate of return (IRR) of a BECCS plant and subsequently evaluate the number of plants, NP, required to meet a given negative emissions target, NT, and the cost per tonne of CO_2 removed, CPTR. The NPV of a given investment is obtained from

$$\mathrm{NPV}(n,r)=\sum_{N=0}^{N}\frac{\mathrm{CF}_n}{(1+r)^n} \quad (1)$$

where n and r are the year of a given cash flow, CF, and the discount rate applied to that CF, respectively. The IRR of a given investment is, formally, that rate r which results in an NPV of zero, obtained by solving the following expression for r

$$\mathrm{IRR}(n,r)=\sum_{n=0}^{N}\frac{\mathrm{CF}_n}{(1+r)^n}=0. \quad (2)$$

The NP required to meet NT is obtained from

$$\mathrm{NP}=\frac{\mathrm{NT}}{\mathrm{CS.MWhYr}_O.10^{-6}} \quad (3)$$

where CS is the quantity of CO_2 sequestered per MWh and MWhYr_O is the number of MWh per year and is in turn calculated via

$$\mathrm{MWhYr}_O=\mathrm{NPC.LF}_O.8760 \quad (4)$$

where NPC is the nameplate capacity of the BECCS plant and LF_O is the average operating load factor of the BECCS plant. Similarly, the levelised cost per tonne of CO_2 removed is calculated via

$$\mathrm{CPTR}=\frac{\mathrm{EAC}.10^6+\mathrm{MC.MWhYr}_O}{\mathrm{CS.MWhYr}_O}. \quad (5)$$

Here, MC is the marginal cost of operating the BECCS plant and is taken to be the sum of the fuel costs, FC, CO_2 transport and storage costs, CTS, and variable operating and maintenance costs, VOM;

$$\mathrm{MC}=\mathrm{FC}+\mathrm{VOM}+\mathrm{CTS}. \quad (6)$$

In this study, we consider that biomass combustion is carbon neutral, and therefore there is no cost imposed for the emission of 'bio-CO_2'. Thus, the equivalent annual cost, EAC, of the BECCS plant is calculated via

$$\mathrm{EAC}=\frac{\mathrm{CPX}}{A_{n,r}} \quad (7)$$

where CPX is the capital cost of the BECCS plant. In this study, CPX is estimated via a regression of data from IECM [27] in terms of higher heating value efficiency, η_{HHV} and is given by

$$\mathrm{CPX}=\frac{932.7\eta_{\mathrm{HHV}}+1153.2}{\mathrm{CCF}}. \quad (8)$$

Here, CCF is a currency conversion between GBP and USD, taken to be £1 = \$1.3 in this study. The annuity factor, $A_{n,r}$ in equation (7) is given by

$$A_{n,r}=\frac{1-\frac{1}{(1+r)^n}}{r} \quad (9)$$

The cash flow of the BECCS plant in any year n is taken to be the sum of the revenue streams associated with operating the plant, R_O and with dispatching electricity, R_D:

$$\mathrm{CF}=(R_O.\mathrm{MWhYr}_O+R_D.\mathrm{MWhYr}_D)10^{-6}. \quad (10)$$

In equation (10), we introduce the distinction between scenario 1 and scenarios 2–3 by distinguishing between the number of MWh per year for which the plant is operating, MWhYr_O and that for which it is dispatching electricity MWhYr_D. Each of these quantities are defined as follows:

$$\mathrm{MWhYr}_O=\mathrm{NPC.LF}_O.8760 \quad (11)$$

and

$$\mathrm{MWhYr}_D=\mathrm{NPC.LF}_D.8760 \quad (12)$$

where NPC is the nameplate capacity of the BECCS plant and LF_O and LF_D correspond to the operating and dispatching load factors, respectively. The R_O is simply the difference between income derived from removing CO_2 from the atmosphere and the marginal cost of BECCS plant operation, MC

$$R_O=\mathrm{CP.CS}-\mathrm{MC} \quad (13)$$

where CP is the payment per tonne of CO_2 removed from the atmosphere and CS is the quantity of CO_2 removed from the atmosphere per MWh generated. However, it must also be recognised that whilst we consider the bio-CO_2 to be carbon neutral, this does not mean that one should receive a negative emissions credit for all of the combustion CO_2 sequestered. This amount should properly be reduced by the amount of CO_2 emitted throughout the biomass supply chain, i.e. the biomass carbon footprint, BCF. Thus, the value of CS is given by:

$$\mathrm{CS}=\mathrm{CI.CCS}-\frac{\mathrm{BCF}}{\eta_{\mathrm{HHV}}} \quad (14)$$

where CI is the carbon intensity of the BECCS plant and CCS is the fraction of CO_2 produced from fuel combustion that is captured and sequestered, taken to be 90% in this study. The plant CI is, of course, a function of the plant efficiency and the carbon content of the fuel, CI_F,

$$\mathrm{CI}=\frac{\mathrm{CI}_F}{\eta_{\mathrm{HHV}}} \quad (15)$$

and

$$\mathrm{CI}_F=\frac{C\frac{44}{12}}{\rho_F^E.2.777\times10^{-7}}. \quad (16)$$

In equation (16), C is the carbon content of the biomass, ρ_F^E is the energy density of the biomass. In this study, single representative values of C and ρ_F^E are used. Obviously, it is possible to find a range of values for both quantities. In practice, however, the carbon content of biomass is typically in the range 47%–49% and it is therefore conceivable that a single average value might be adopted for ease of regulation. Finally, the factor of 2.777×10^{-7} is to convert MJ to MWh and kg to tonnes[7]. The revenue derived from dispatching electricity is simply

$$R_D = \mathrm{EP.MWhYr}_D \tag{17}$$

where EP is the electricity price and MWhYr_D is as defined in equation (12). The connection between plant efficiency and load factor has been neglected in this study in order to preserve efficiency as an independent variable. In order to calculate the MC, we need to calculate FC, CTS and VOM. The fuel costs are calculated via

$$\mathrm{FC} = \frac{\mathrm{FC}_M.1 \times 10^{-3}}{\eta_{\mathrm{HHV}}.\rho_F^E.2.777 \times 10^{-4}} \tag{18}$$

where FC_M is the mass-based fuel cost, taken to be £50 t^{-1} in this study, and is line with the costs reported in Seikfar *et al* [28]. This is a representative value, with biomass prices having the potential to vary substantially in practice. Lastly, the cost associated with CO_2 transport and storage, CTS is given by

$$\mathrm{CTS} = \mathrm{CD}_M.\mathrm{CS} \tag{19}$$

where CD_M is the cost per tonne for CO_2 transport and storage, assumed to be £20/t_{CO_2} in this study, and CS is as defined in equation (14). In order to evaluate the role and value of hydrogen production, we first quantify the amount of electricity which was produced but not dispatched, Q_S via

$$Q_S = \mathrm{MWhYr}_P - \mathrm{MWhYr}_D \tag{20}$$

and then the amount of hydrogen produced, HP, is found directly

$$\mathrm{HP} = \frac{Q_S.1 \times 10^3}{\mathrm{HC}}, \tag{21}$$

where HC is the power required to produce 1 kg of H_2, taken to be 53.4 kWh kg^{-1} in this study [29]. We then proceed to calculate the number of electrolyser units required to produce this much H_2, NE,

$$\mathrm{NE} = \frac{\mathrm{HP}}{\mathrm{EC.LF}_O.8760} \tag{22}$$

where EC is the capacity of an individual electrolyser. An expression for the specific capital cost of each electrolyser, SPCPX, as a function of EC was estimated from published data [29] and is

$$\mathrm{SPCPX} = \frac{18.\mathrm{EC}^{0.6}}{\mathrm{CCF}} \tag{23}$$

where SPCPX has units of k£. Finally, the total capital cost of the electrolysis plant, ECPX, in M£, is estimated from

$$\mathrm{ECPX} = \mathrm{NE.SPCPX}.1 \times 10^{-3}. \tag{24}$$

Therefore, for Sc3, the term ECPX was added to the capital cost of the BECCS plant defined by equation (8). Where hydrogen was produced and sold, it was assumed to displace natural gas (primarily CH_4) for heating and therefore its value was indexed to that of CH_4 on a heating value basis [30]. For this exercise the CH_4 price was assumed to be £25 MWh^{-1} [31] and H_2 was assumed to have an energy density of 39 kWh kg^{-1}, and therefore H_2 could be sold for approximately £1 kg^{-1}. Again, this was simply added to equation (13) in order to calculate the revenue under Sc3.

The construction period of a CCS plant is typically estimated to be between 4–6 yr [32], and an estimate of 5 yr was used in this study. Similarly, whilst it is common for large industrial facilities to take up to four years to achieve design point operation [33], this nuance was not considered here - we assumed that the BECCS plant was capable of design point operation as soon as construction was completed. A technical project lifetime of 50 yr (including construction) was assumed. For project financing, a debt-to-equity ratio of 70/30 was assumed, with debt assumed to be available at 5% and equity valued at 8%, yielding a weighted average cost of capital (WACC) of approximately 6%, this is in line with other estimates [34]. Future cash flows were discounted at a rate of 5%. The biomass fuel was considered to be woodchips and a conservative cost of £50 t^{-1} was assumed [28]. This biomass was assumed to have an energy density of 18.2 MJ kg^{-1} with 5% moisture and to be 47.5 wt% carbon[8]. In line with common practice [35, 36], 90% CO_2 capture was assumed in all cases. CO_2 transport and storage costs of £20/t_{CO_2} and variable operating and maintenance costs of £4.38 MWh^{-1} were assumed [37]. Lastly, an average wholesale price of electricity of £80 MWh^{-1} was assumed [24]. On this basis, and assuming a reference BECCS plant with $\eta_{\mathrm{HHV}} = 42\%$ and a load factor of 85%, a central value of £75/t_{CO_2} as a payment for the CO_2 removed from the atmosphere was chosen as it was found to provide an IRR of 12%[9], noting that this price is a linear function of both biomass cost and electricity price. For comparison, in the absence of this payment for removing CO_2 from the atmosphere, in order to achieve an IRR of 12%, the

[7] $2.777 \times 10^{-7} = 2.777 \times 10^{-4} \frac{\mathrm{MWh}}{\mathrm{MJ}}.1 \times 10^{-3} \frac{t}{\mathrm{kg}}$.

[8] On a dry basis, this is 19.2 MJ kg^{-1} and 50 wt% carbon

[9] A reasonable value for a private investment in an utility grade asset

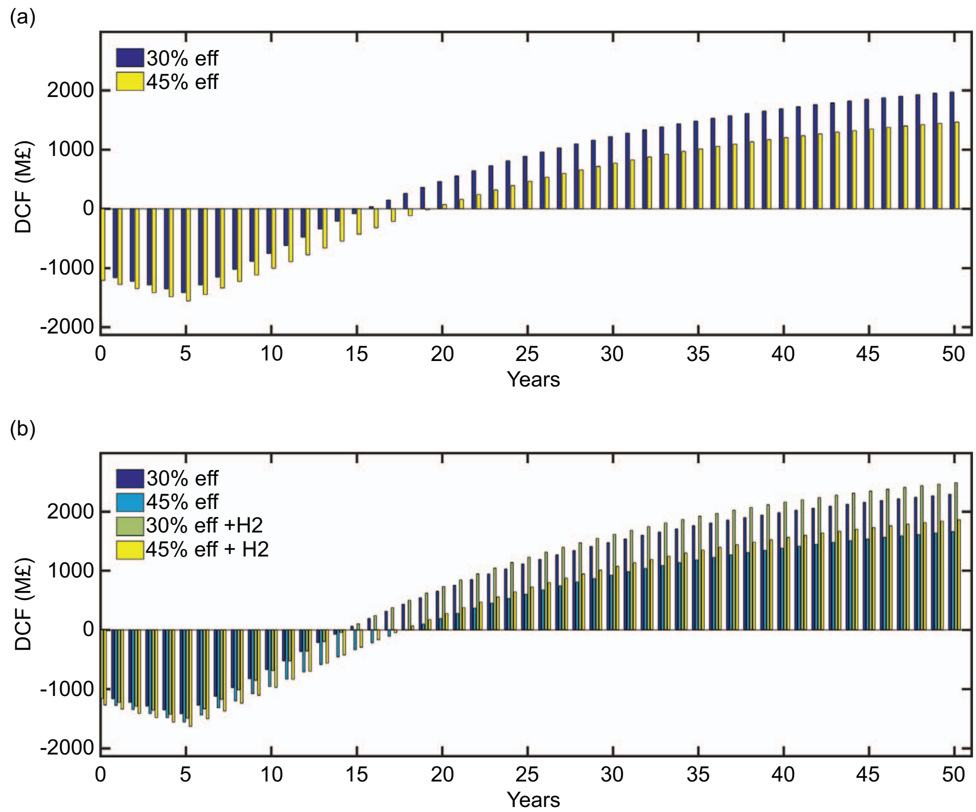

Figure 1. A discounted cash flow (DCF) analysis for high efficiency, high CAPEX and low efficiency, low CAPEX for (*a*) Scenario 1 and (*b*) Scenarios 2 and 3. All scenarios assume that both plants dispatch electricity at a load factor of 60%, and Scenario 2 and 3 assumed an operating load factor of 85%. The value of removing CO_2 from the atmosphere is taken to be £75/tCO_2. In all scenarios, the less efficient BECCS plant has a shorter break-even time and has an NPV greater than that of its more efficient counterpart by 34%–38%.

BECCS plant would need to receive a payment of approximately £130 MWh^{-1} of electricity dispatched, still assuming an 85% load factor.

3. Results and discussion

3.1. Discounted cash flow analysis of BECCS

We begin our analysis by considering a discounted cash flow analysis (DCF) of a BECCS facility. In figure 1, we present a discounted cash flow analysis of both the high- and low-efficiency BECCS facilities for each of scenarios 1–3. For this illustrative example, we consider the limits of our range, i.e. η_{HHV} of 30 and 45%, respectively.

In all cases, the inefficient BECCS facility is more profitable than its more efficient counterpart, assuming similar operating patterns. In the case of Sc1, the inefficient plant has an NPV of approximately £1982 M, relative to that of the efficient plant at approximately £1469 M. In Sc2, this increases by 16% and 13%, respectively. The addition of hydrogen production in Sc3 has a further positive effect, adding a 9% and 12% to the NPV, respectively. A detailed breakdown of the un-discounted cash flow is presented in figure 2 for clarity.

As can be observed, the primary cost incurred over the lifetime of the BECCS plant, regardless of scenario, is fuel, followed by the cost associated with CO_2 transport and storage. The primary source of income in Sc1 is the sale of electricity, closely followed by the payment received for removing CO_2 from the atmosphere, but once the BECCS plant operates at constant capacity, regardless of electricity dispatch, this payment substantially increases, substantially improving the total positive cash flow, and in the case of the less efficient option, reversing entirely. The income associated with selling hydrogen is observed to be a non-negligible but is a distant third under this scenario. Here, we considered that the H_2 was sold in order to displace natural gas for space heating, and as such commanded the relatively low price of £1/kg$_{H_2}$.

An important element which was not considered in this analysis is any potential income arising from CO_2 emissions that are avoided as a result of utilising of CH_4. For the BECCS plant operating with a 60% dispatch factor in Sc3, this is equivalent to producing approximately 20 506 t_{H_2}/yr, which displaces approximately 55 680 t_{CH_4}/yr[10] and thus avoids the emission of 0.15 Mt_{CO_2}/yr. Assuming that a similar payment was available for CO_2 avoided as for CO_2 removed, this would correspond to an additional income on the order of £11 M yr^{-1}.

[10] on an HHV energy basis

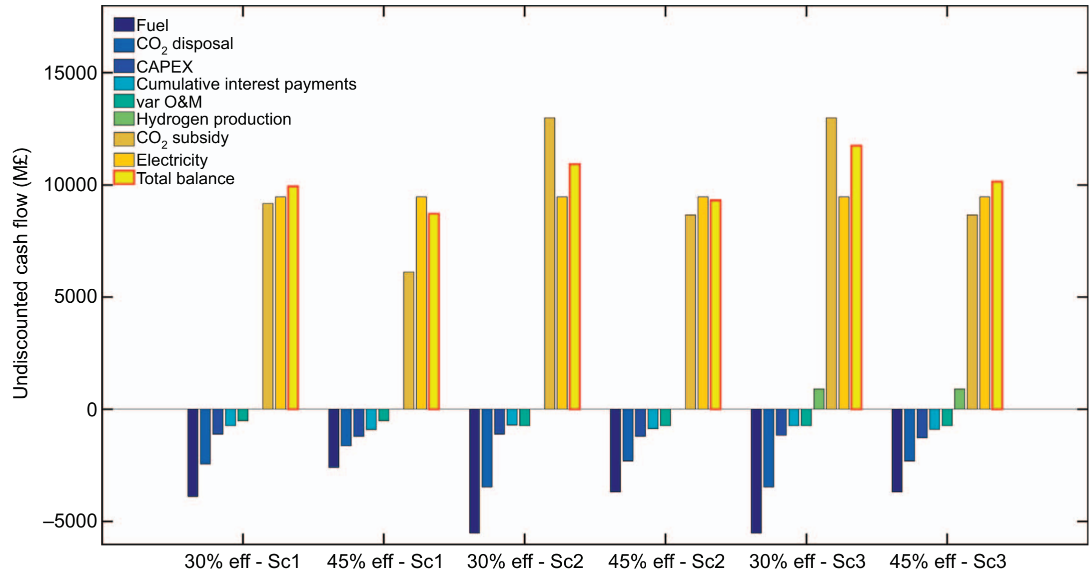

Figure 2. A breakdown of the key (undiscounted) contributions to project cash flow is presented here. Again, it can be observed that the less efficient BECCS plant is a more profitable option, and that in the scenario where 'excess' electricity is used to produce hydrogen via electrolysis, a non-negligible tertiary income is derived from its distribution.

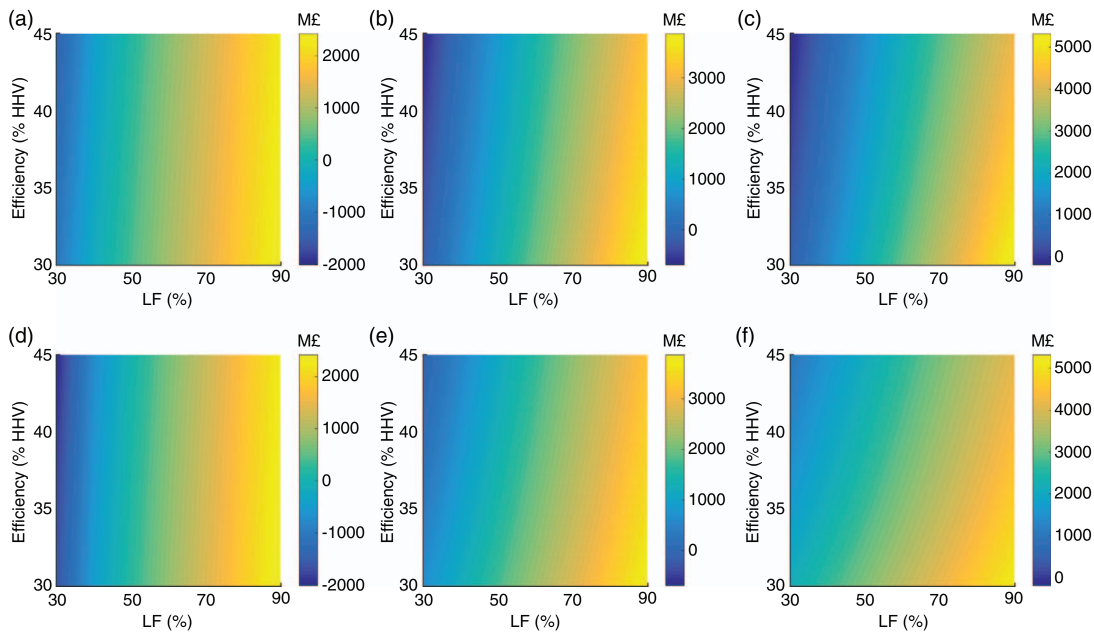

Figure 3. The net present value (NPV) of BECCS plants as a function of power plant load factor and efficiency is shown here at a constant electricity price of £80 MWh^{-1} and for CO_2 prices of £50/t_{CO_2} (*a*) and (*d*), £75/t_{CO_2} (*b*) and (*e*), £100/t_{CO_2} (*c*) and (*f*). The NPV corresponding to Scenario 1 is illustrated in sub-figures (*a*)–(*c*) and that associated with Scenario 2 is is illustrated in sub-figures (*d*)–(*f*), respectively. In general, the less efficient plants have a greater NPV than their more efficient counterparts. The price paid for CO_2 removal from the atmosphere exerts a first-order influence on the NPV with load factor exerting a strong, but second-order influence.

However, whilst it is evident that the income derived from hydrogen production is potentially important, it does not qualitatively affect the results of this work, and will therefore not be discussed further in this analysis. The key observation at this point is that the less efficient plants will of necessity burn more biomass over the plant lifetime, and therefore has the potential to remove substantially more CO_2 from the atmosphere than the more efficient plant.

3.2. Net present value (NPV) and internal rate of return (IRR)

Building on the previous discussion, the NPV of a given plant is clearly a function of the power plant efficiency, the average load factor and the income derived from removing CO_2 from the atmosphere. This was explored in depth, and the associated results are presented in figure 3.

As can be qualitatively observed from figure 3, there is a complex tradeoff between efficiency, load

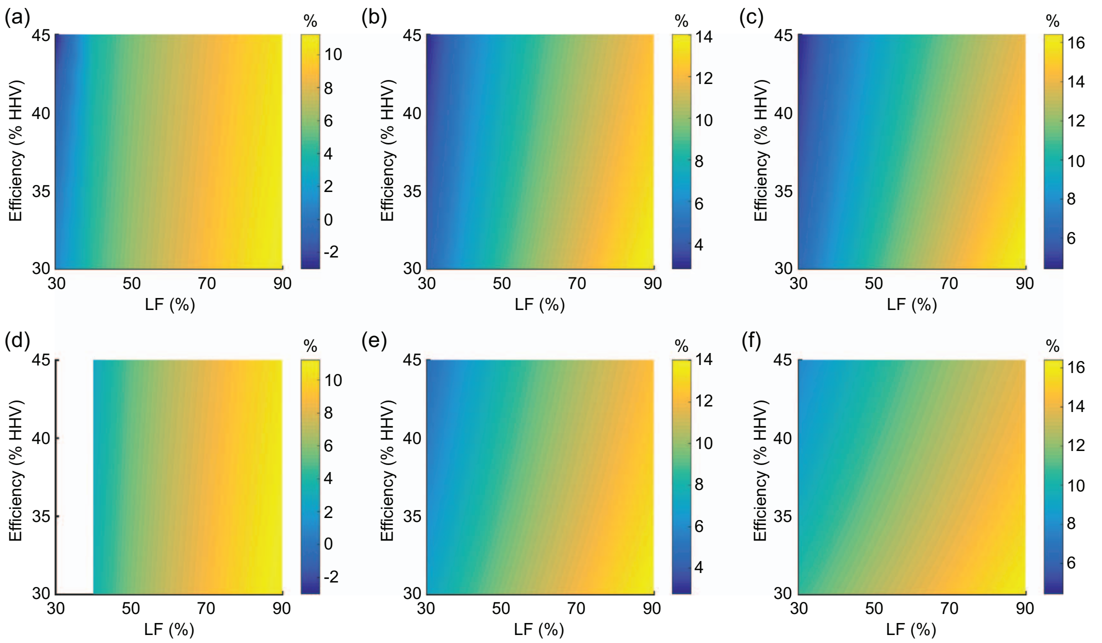

Figure 4. The internal rate of return (IRR) of BECCS plants as a function of power plant load factor and efficiency is shown here at a constant electricity price of £80 MWh^{-1} and for CO_2 prices of £50/t_{CO_2} (*a*) and (*d*), £75/t_{CO_2} (*b*) and (*e*), £100/t_{CO_2} (*c*) and (*f*). The IRR corresponding to Scenario 1 is illustrated in sub-figures (*a*)−(*c*) and that associated with Scenario 2 is is illustrated in sub-figures (*d*)−(*f*), respectively. In general, the less efficient plants have a greater IRR than their more efficient counterparts. The price paid for CO_2 removal from the atmosphere exerts a first-order influence on the IRR with load factor exerting a strong, but second-order influence. Tellingly, for a given load-factor, the less efficient plant always has a greater IRR than the more efficient plant. Note that in the case of (*d*), the white area in the left hand side of the plot corresponds to a region of negative IRR.

factor and CO_2 price. At low CO_2 prices, as in figures 3(*a*) and (*d*), the dispatch load factor exerts a first order effect on the NPV. As the CO_2 price increases, the influence of dispatch load factor on NPV is reduced. In all cases, the less efficient plants are more profitable at a given load factor than the more efficient plant—this trend may be qualitatively observed from figures 3(*b*), (*c*), (*e*) and (*f*).

These trends are somewhat more evident when the viability of this investment is expressed in terms of the internal rate of return, as in figure 4.

As can be observed from figure 4, IRR is inversely proportional to BECCS plant efficiency. Tellingly, for a given load-factor, the less efficient plant always has a greater IRR than the more efficient plant.

These results can be conveniently summarised in terms of the total amount of CO_2 removed from the atmosphere per year per plant, the number of 500 MW units required to meet a target of $-50\,Mt_{CO_2}$/yr and the levelised cost per tonne of CO_2 removed from the atmosphere over the lifetime of the BECCS facility. This target was chosen as it is in line with potential UK targets [38]. These metrics are illustrated in figure 5.

Several points are immediately apparent from figure 5. Firstly, the distinction between Sc1 and Sc2 is substantially more apparent here than in the previous graphics. Firstly, the less efficient plants remove substantially more CO_2 per year than the more efficient plants. This is the chief motivation for operating the less efficient BECCS plants in baseload fashion - it results in an increase in the total amount of CO_2 removed from the atmosphere per unit per year; approximately $2.7\,Mt_{CO_2}$/yr to approximately 4.1 Mt_{CO_2}/yr for the most and least efficient plants, respectively. This, in turn, substantially reduces the number of units required to achieve the aforementioned target of $-50\,Mt_{CO_2}$/yr and thus a reduced marginal abatement cost.

3.3. The impact of embodied carbon on system performance

The previous analysis was performed from the perspective of a BECCS power plant, neglecting the biomass supply chain, using the simplifying assumption that the biomass delivered to the power plant was carbon neutral. This is, of course, not true, and CO_2 emissions associated with biomass cultivation, harvesting, processing and transport can be relatively high [39, 40], and would, if included in the carbon balance on the system, decrease the carbon negativity of the BECCS power plant, or, if sufficiently great, lead to the BECCS facility being a net emitter of CO_2.

The UK Bioenergy Strategy [41] identifies a value of 285 $kg_{CO_{2eq}}$ per MWh of bioelectricity as the upper limit of GHG emissions embedded in the supply chain for that bioenergy to be considered sustainable. However, owing to the uncertainty associated with their quantification, indirect land use change (ILUC) emissions are not included within this definition. For reference, Drax reports [42] a value of 36 $g_{CO_{2eq}}$ per MJ of electricity generated, or between 39–58 $kg_{CO_{2eq}}$ per

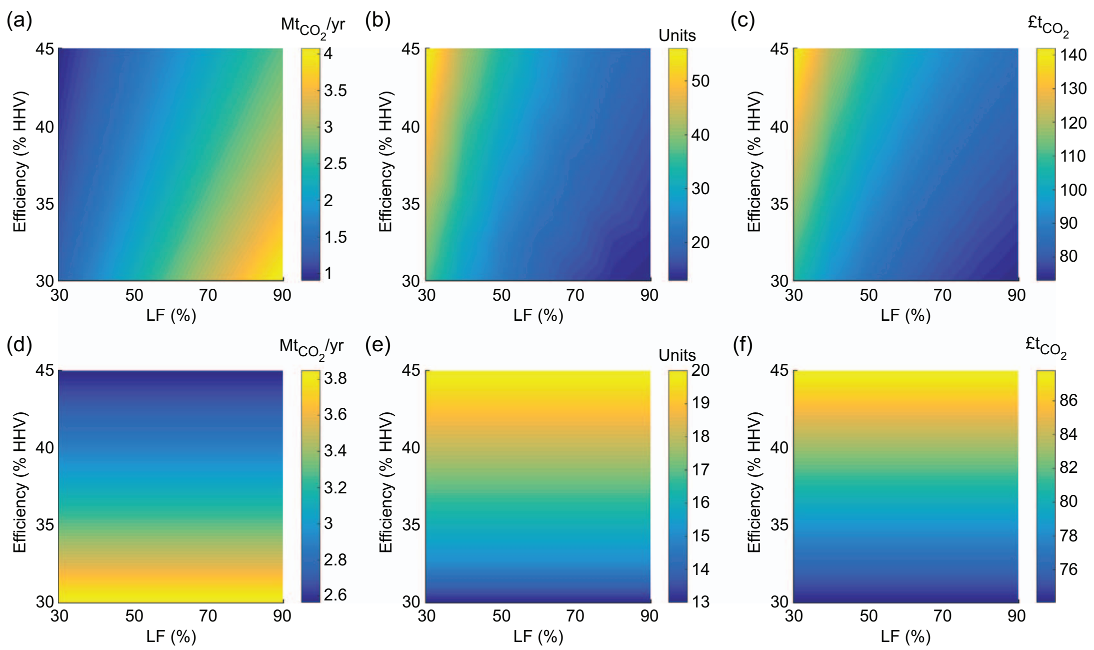

Figure 5. The amount of CO_2 removed from the atmosphere per year (*a*) and (*d*), the number of 500 MW BECCS units required to meet UK targets (*b*) and (*e*) and the price per tonne of CO_2 removed from the atmosphere (*c*) and (*f*) are shown here. In general, the less efficient plants remove more CO_2, require few units and have a substantially reduced cost per tonne of CO_2 removed. The importance of load factor is evident from a comparison of sub-figures (*a*)–(*c*) with (*d*)–(*f*). It can be observed that, simply by running the unit at maximum capacity, an 'inefficient' BECCS plant can remove approximately 50% more CO_2 from the atmosphere per year than its more efficient counterpart.

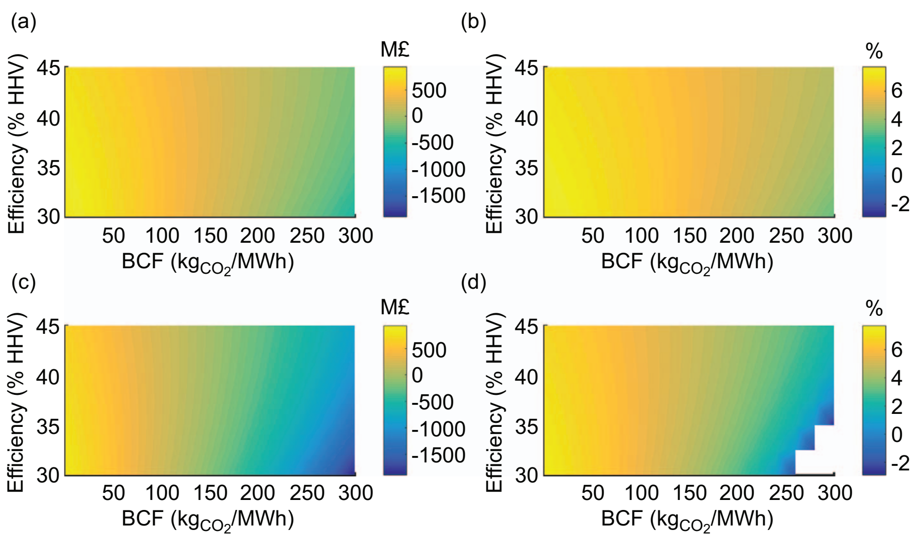

Figure 6. The net present value (NPV) and internal rate of return (IRR) of BECCS plants as a function of biomass carbon footprint and efficiency is shown here at a constant electricity price of £80 MWh^{-1} and for CO_2 prices of £50/t$_{CO_2}$ for Sc1 (*a*) and (*b*) and Sc2 (*c*) and (*d*). Up to a limiting value of BCF ≥ 135 kg$_{CO_{2eq}}$ per MWh, the less efficient plants have a greater NPV and IRR than their more efficient counterparts.

MWh of primary bioenergy, as a function of the efficiency of the conversion process.

Thus, in order to evaluate the impact of including embodied GHG emissions on the foregoing results, we evaluated the impact of using a fuel with a biomass carbon footprint (BCF) in the range 0–300 kg$_{CO_{2eq}}$ per MWh. As before, the performance indicators were NPV, IRR, cost per ton of CO_2 removed (CPTR) and annual CO_2 sequestered (CS) of a BECCS project, and their variation with the system power generation efficiency, under the previously described operating scenarios. For this analysis, the dispatch load factor, electricity price and negative emission credit were set to 60%, £80 MWh^{-1} and £50/t$_{CO_2}$, respectively. The results of this analysis are presented in figures 6 and 7.

In figures 6(*a*) and (*b*), i.e. Sc1, for all values of BCF less than 135 kg$_{CO_{2eq}}$ per MWh of primary bioenergy delivered, the less efficient power plants are uniformly more profitable than their more efficient counterparts. For reference, this is approximately

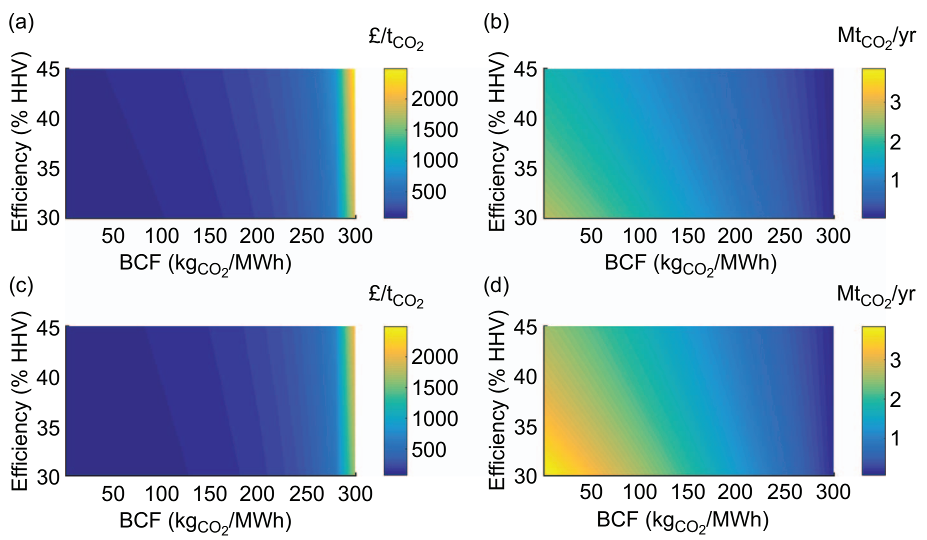

Figure 7. The cost per tonne of CO_2 removed (CPTR) and the amount of CO_2 removed (CR) per year for BECCS plants as a function of biomass carbon footprint and efficiency is shown here at a constant electricity price of £80/MWh and for CO_2 prices of £50/t_{CO_2} for Sc1 (*a*) and (*b*) and Sc2 (*c*) and (*d*). At low carbon footprint values, efficiency has a first order impact on BECCS CPTR and CS. As biomass carbon footprint increases, this impact becomes secondary relative to the biomass carbon footprint. Above 270 $kg_{CO_{2eq}}$ per MWh, the cost of removing one ton of CO_2 significantly increases for both scenarios, and the impact of using unsustainable biomass significantly outweighs the impact of power plant efficiency.

2.8 times greater than the value reported by Drax. However, above this value, the trend begins to reverse, and the more efficient units become more profitable. What is being observed is that, as the system efficiency decreases, the increase in revenue associated with the negative emission credit becomes too low to compensate for the decrease in the electricity revenue, resulting in an overall lower NPV and IRR for less efficient systems.

In Sc2, the point at which this transition occurs is reduced to 90 $kg_{CO_{2eq}}$ per MWh. Here, recall that the plant is operating in baseload fashion, i.e. sequestering CO_2 at an 85% capacity factor but dispatching electricity at 60% of nameplate capacity. Therefore, the revenue associated with the sale of electricity is reduced relative to the short run marginal cost, and thus overall profitability is reduced.

An evaluation of the biomass carbon footprint on the cost per tonne of CO_2 removed from the atmosphere and the amount of CO_2 removed per year is presented in figure 7.

As can be observed from figure 7, at low carbon footprint values, efficiency has a first order impact on both the cost per tonne of CO_2 removed (CPTR) and also the amount of CO_2 removed from the atmosphere (CR) of a given BECCS facility. However, as the biomass carbon footprint increases, the importance of plant efficiency decreases. For a biomass carbon footprint greater than 270 $kg_{CO_{2eq}}$ per MWh, the cost of removing one ton of CO_2 is observed to significantly increase. Specifically from £640/t_{CO_2} at 270 $kg_{CO_{2eq}}$ per MWh to £2500/t_{CO_2} at 300 $kg_{CO_{2eq}}$ per MWh for a 45% efficient power plant. This can be observed in the figures 7(*a*) and (*c*) as an abrupt transition from blue to green. This can be elucidated by inspection of figures 7 (*b*) and (*d*). Initially, the less efficient plants remove significantly more CO_2 from the atmosphere than the more efficient plants. However, as the biomass carbon footprint increases, the amount of CO_2 removed per year decreases, and beyond 270 $kg_{CO_{2eq}}$ per MWh, the impact of power plant efficiency becomes negligible relative to that of the embodied carbon footprint of the biomass.

This serves to reinforce the original hypothesis of this study that for a given system, power plants that are less efficient at converting primary bioenergy into bioelectricity, and thus are commensurately lower in capital cost, will consistently remove more CO_2 from the atmosphere per year and at a lower cost per tonne removed than their more efficient counter parts.

The only point where this hypothesis breaks down is where the embodied carbon in the bioenergy is sufficiently large so as to render the impact of power plant efficiency negligible and thus the dominant factor is the power plant capital cost, and the sale of electricity becomes more valuable than the removal of CO_2 from the atmosphere.

Given that the purpose of building and operating the BECCS facilities is arguably to achieve least cost atmospheric CO_2 removal, then what might initially be considered to be a sub-optimal choice—building BECCS facilities which are inefficient at converting biomass to electricity and operating them in baseload fashion—may actually be the cost optimal route to removing CO_2 from the atmosphere.

4. Summary and conclusions

We have presented a techno-economic environmental model of a BECCS power plant and considered its operation under three distinct operating scenarios, using project NPV, IRR, tonnes of CO_2 removed from the atmosphere per unit per year, number of units required and cost per tonne of CO_2 removed as key performance indicators. Assuming that there is a revenue stream associated with the removal of CO_2 from the atmosphere, in addition to the default revenue stream associated with the production of electricity, we find that in all cases BECCS facilities which are 'inefficient' at converting biomass to electricity, thus consuming more biomass per MWh of power produced or per year of operation, remove more CO_2 from the atmosphere per year at a lower cost than their more efficient counterparts.

This result is driven by the fact that higher efficiency plants tend to cost more than their less efficient counterparts, thus taking longer to break even on the initial investment and also that, given that the less efficient plants consume more biomass, producing and sequestering more CO_2, they will receive a larger revenue from providing this service. This would appear to incentivise the baseload operation of BECCS plants, constantly removing CO_2 from the atmosphere and dispatching electricity in response to a market demand.

Given that many scenarios associated with climate change mitigation assume very substantial levels of deployment of intermittent renewable energy (iRE), it is reasonable to expect that the dispatch load factor of thermal power plants, such as BECCS plants, may be quite low. In other words, for a BECCS facility, a primary method of value provision may well be in the removal of CO_2 from the atmosphere, with electricity generation acting to provide supplementary income. Thus, a mechanism through which this value can accrue to the service providers this may be key to providing a sufficiently attractive investment proposition. We note that the provision of ancillary services may well be an important route to potential revenue streams for thermal power plants, regardless of fuel types. This has not been explored in this study, but is considered a priority for future research in this area.

This hypothesis would appear to break down only when the CO_2 emissions associated with the biomass supply chain are sufficiently large so as to very significantly reduce, or eliminate, the amount of CO_2 being removed from the atmosphere. In this case, the BECCS facility reverts to being a power generation facility as opposed to a CO_2 removal facility, at which point a more efficient facility is again preferred.

We also considered the possibility of co-location and integration of an electrolysis process for hydrogen production from 'surplus' electricity, considering its role in further displacing CH_4 from the heating system. In performing this evaluation, we deliberately chose a conservative scenario, i.e. one where the BECCS plant with an $\eta_{HHV} = 45\%$, had an electricity dispatch factor of 60% and an operating load factor of 85%. This dispatch load factor is in line with the upper bound of what might be expected for thermal power plants in scenarios with high rates of iRE deployment. This was found to correspond to the displacement of over 55 600 t_{CH_4}/yr[11], therefore leading to the avoidance of a further 0.15 Mt_{CO_2}/yr. If the dispatch load factor is decreased to 40%, meaning that there is more 'surplus' electricity available for H_2 production, the quantity of natural gas displaced increased to slightly more than 100 200 t_{CH_4}/yr and the amount of avoided CO_2 increased to approximately 0.27 Mt_{CO_2}/yr. The option of H_2 production from utilisation of non-dispatched electricity contributes positively to the economics of negative emissions technologies such as BECCS, noting that we did not consider an additional income arising from avoiding CO_2 emissions from the use of natural gas. Biomass gasification with CO_2 capture for the production of carbon negative hydrogen is an obvious alternative BECCS technology. This therefore warrants further evaluation in future work, noting that this H_2 could similarly be used for provision of heat or power in addition as an energy vector for transport or as an industrial feedstock.

Finally, the ability of BECCS technology to potentially provide several services—atmospheric CO_2 removal, in addition to carbon negative electricity and H_2—implies that it may be more commercially attractive than other some of the other options for atmospheric CO_2 removal. However, the deployment of BECCS is, of course, reliant on the availability of sufficient sustainably sourced biomass, an active CCS industry operating at scale and a favourable policy and commercial environment to incentivise these investments.

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