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Biomass in the electricity system: A complement to variable renewables or a source of negative emissions?

Viktor Johansson [a,*], Mariliis Lehtveer [a,b], Lisa Göransson [a]

[a] Department of Space, Earth and Environment, Chalmers University of Technology, Gothenburg, Sweden
[b] The Centre for Climate Science and Policy Research (CSPR), Department of Thematic Studies—Environmental Change, Linköping University, Sweden

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ABSTRACT

Biomass is often assigned a central role in future energy system scenarios as a carbon sink, making negative greenhouse gas emissions possible through carbon capture and storage of biogenic carbon dioxide from biomass-fuelled power plants. However, biomass could also serve as a strategic complement to variable renewables by supplying electricity during hours of high residual load. In this work, we investigate the role of biomass in electricity systems with net zero or negative emissions of carbon dioxide and with different levels of biomass availability. We show that access to biomass corresponding to ca. 20% of the electricity demand in primary energy terms, is of high value to the electricity system. Biomass for flexibility purposes can be a cost-efficient support to reach a carbon neutral electricity system with the main share of electricity from wind and solar power. Biomass-fired power plants equipped with carbon capture and storage in combination with natural gas combined cycle turbines are identified as being the cost-effective choice to supply the electricity system with flexibility if the availability of biomass within the electricity system is low. In contrast, in the case of excess biomass, flexibility is supplied by biomethane-fired combined cycle turbines or by biomass-fired power plants.

1. Introduction

If the increase in global warming is to be restricted to less than 2 °C with reasonable certainty, global greenhouse gas (GHG) emissions must decrease by roughly half by the mid-21st Century, as compared to the current levels, and continue to decline thereafter [1]. To achieve the 1.5 °C target set by the Paris Agreement, negative emissions will likely be needed in the second half of the century, to compensate for the emissions in the first part of the century or for sectors that are difficult to mitigate completely, such as agriculture [2]. The power sector is one of the main sources of emitted anthropogenic GHGs, accounting for about 30% of the total global emissions [3]. This and several affordable alternative technologies to current production make it one of the main targets for emissions reductions.

In recent years, the share of low-carbon electricity generation from wind and solar sources has expanded significantly, and it is expected to continue to do so in the coming decades owing to lower costs and policy incentives that are fuelled by climate and energy security concerns. However, large-scale expansion of wind and solar power creates a new set of challenges. The energy supplied from wind and solar technologies is variable in both the short and long terms. High levels of wind and solar power complicate systems operation by changing the shape of the residual load and exacerbating the uncertainty of supply. On the one hand, if significant amounts of intermittent capacity are installed in the system there may be an over-supply of electricity on windy and sunny days, which would result in periods of low electricity prices. On the other hand, when wind and solar power production is too low to meet the demand, other power plants must be deployed. Their full-load hours will, however, be reduced by wind and solar infeed, while requirements in relation to flexibility will increase compared to current thermal generation. Thus, the variability of solar and wind generation can be expected to have a strong influence on investment decisions in the electricity system over the coming decades.

Biomass could be used to complement wind and solar power in a zero-emissions power system. In the latest IPCC assessment report (AR5), biomass is designated an important role in the power system, with median electricity produced from biomass globally being 7 EJ in Year 2050 and with 0–72 EJ for all the scenarios. For stringent climate scenarios, biomass in combination with carbon

* Corresponding author.
E-mail address: viktor.johansson@chalmers.se (V. Johansson).

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capture and storage (BECCS) is also seen as a potential way of enabling negative CO_2emissions. The median amount of electricity provided by BECCS in AR5 scenarios likely to achieve the 2 °C target is 8 EJ in Year 2050 globally. Although several technologies have the potential to enable negative emissions, for example afforestation or direct air capture CO_2, BECCS has the advantage of simultaneously providing benefits other than mitigation (e.g., electricity and heat, biofuels or pulp and paper). However, biomass is a limited resource and there are significant uncertainties related to how much of it can be provided to the energy system in a sustainable manner [4,5]. Furthermore, it is uncertain as to where in the energy system the available biomass should be used. Mitigation may be more difficult in sectors other than electricity production, such as fuel production for aviation, or biomass may simply be needed as a feedstock for products, such as plastics [6].

If biomass is to be used in the power sector, there are several strategies for its deployment. Biomass may be burned directly or converted into biomethane and used in gas turbines, with the latter being a process that provides more flexibility in terms of regulating power output. These two applications can be combined with carbon capture and storage (CCS) to achieve negative emissions. Moreover, hydrogen can be added to biomethane production to exploit the excess carbon atoms in the biomass, which would otherwise not be converted into methane [7]. It is not clear how the choice of biomass technologies relates to biomass availability and the resources for variable renewables.

Previous emphasis in the literature has been on the so-called value of wind and solar power, e.g., how increasing the level of variable production decreases the full-load hours of other plants in the system or the capacity credit provided by these variable sources [8,9]. However, the interplay that occurs between wind, solar, and biomass, the combination of which is potentially needed for a zero-emissions electricity system, has been largely neglected. A previous study conducted by Johansson and Göransson [10], which assessed the impacts of variation management on the cost-optimal share of wind and solar photovoltaics (PV) in different European regions, included cheap biomass as one possible variation management option. They found that depending on the wind and solar resources, cheap biomass could both increase and decrease the share of variable renewables in the system.

The aim of the present work was to contribute to filling the current knowledge gap in three ways:

- First, grounded on the potentially limited availability of biomass for electricity production, to estimate the value of biomass in the electricity system.
- Second, to determine which biomass-based technologies are part of the least-cost electricity system composition under different biomass availability levels and with different emissions targets.
- Third, to investigate the conditions under which biomass-based technologies and variable renewables act as complements or competitors within the electricity system.

2. Methodology

2.1. Basic model

The role of biomass in a biomass- and carbon-constrained electricity system is evaluated by applying a linear, cost-minimising electricity system investment model. The original model is presented in previous work [11] and is designed to give a good representation of variability and variation management on the intra-annual time-scale. The model represents the electricity system operation over a year with a temporal resolution of 3-h. The start-up time, start-up costs, and minimum load level of thermal generation are accounted for as suggested by Weber [12] and evaluated by Göransson [13]. Thermal generation with improved flexibility was added to the model in a subsequent study [14]. Johansson and Göransson [10] complemented the model with variation management strategies, including batteries, demand-side management (DSM), and hydrogen storage.

To accommodate a detailed description of inter-hourly variability, the geographical resolution is reduced, and the model is applied to one copperplate-region at a time. A green-field approach is adopted, which assumes as the starting point an empty system without any generation capacity in place. Thus, the model is not designed to create a realistic representation of any actual region but instead to investigate the linkages and dynamics between the different parts of the electricity generation system. However, in order to assure realistic combinations of wind and solar resources and electricity demand, the wind, solar, and load data from actual regions in Europe for year 2012 are applied [15–17]. In this work, three regions have been selected for their large differences in wind and solar resources: one region with good wind conditions (IE -Ireland); one region with good solar conditions (ES3 -central Spain); and one region with relatively poor conditions for wind and solar generation (HU -Hungary).

The technology cost data, fuel prices, and data on renewable resources and generation profiles applied in this work are listed in Appendix A. Four different types of variation management technologies are included in this work: (redox) flow batteries; lithium-ion (Li-ion) batteries; hydrogen storage; and DSM. DSM, as implemented here, implies that up to 20% of the hourly demand for electricity can be delayed for up to 12 h (see Ref. [10] for a complete description of the DSM implementation).

2.2. Model development

In addition to previous versions of the model, several new, bio-based, generation technologies have been added in this work. Biomass-fuelled steam power plants with CCS (biomass CCS), as well as combined cycle gas turbines with CCS fuelled with bio-based methane (biomethane CCS) are modelled as negative emission technologies. In addition, a carbon-neutral mix of co-fired biomethane and natural gas with CCS (biomethane-NG CCS) has been added to the technology options. The capture rate, additional costs for the CCS part, and efficiency penalties are assumed to be equal to their corresponding fossil-fuelled versions. In previous studies [10,11], biomethane was assumed to be generated from biomass through indirect gasification with 70% efficiency. Although biomass is generally assumed to be climate-neutral, emitting biogenic CO_2 could represent a loss in a biomass-constrained world. If only a little biomass is available, CO_2 molecules may become valuable for the synthesis of materials and fuels, as well as for attaining negative emissions. The basic process of indirect gasification emits biogenic CO_2 from both the combustion of biomass and the conversion of biomass to biomethane, since the latter have a lower carbon intensity. These two sources of CO_2 emissions can be addressed in separate ways. Exchanging part of the combustion for electrical heating reduces the first source and allows the system to become a semi-flexible electricity consumer (i.e., flexible in the case of over-dimensioning of the plant so that it can shut down during high-electricity-price hours). A share of the second source of CO_2 could be combined with hydrogen in a methanation unit, to enhance the biomethane production (this option could work for both sources, although the first source is usually not as pure in terms of CO_2 due to mixing with air). If CO_2 is re-circulated in the reactor this method has the potential to convert fully the CO_2 into methane [18]. In the Sabatier reaction in the methanation step, water is produced, which entails a loss of energy to heat, thereby adding to the overall energy losses associated with producing biomethane from electricity via hydrogen. Nevertheless, this option may be used when biomethane is highly valued and hydrogen is available at a low cost. For these routes, indirect gasification has been modelled with the following options: (i) gasification with biomass to produce biomethane and process heat; (ii) conversion of biomass to biomethane, with electricity providing the process heat; (iii) same as option (i) with a larger methanation unit, which requires the addition of hydrogen from an external source; (iv) a combination of options (ii) and (iii) that maximises the biomethane output from the biomass. The first three options represents designs A.2 (LT), A.5 (max_{El}), and A.4 (max_{El}), respectively, from the work by Alamia et al. [19], and the fourth option is a combination of the two last, the input output of the gasifiers are shown in Table A.2 in Appendix A.

Fuel cells are added to the technological data, in addition to the electrolyser and hydrogen storage previously included in the model [10]. The addition of fuel cells creates an endogenous demand for hydrogen as a means of electricity storage. The costs and efficiencies for the electrolyser, fuel cell, and hydrogen storage, as well as for batteries are given in Table A.4 in Appendix A.

2.3. Studied cases

In this study, four different cases were tested. In our *base case*, we assumed net-zero emissions from the system and that the investments in all generation technologies and flexibility measures given in Appendix A are available. In the *base case*, DSM is also available for variation management. In the *noCCS case*, it is assumed that no CCS technologies will become available due to perceived security or other political concerns, such as "not in my back yard" issues. Similarly, in the *noFlex case*, we limited the access to flexibility-enhancing measures, in that DSM was removed and investments in batteries and hydrogen storage were excluded. The final case, which is called the *negative case*, requires 10% of negative emissions compared to the level of emissions in the electricity sector in Year 1990. This case aims to test the hypothesis that negative emissions from the electricity sector may be needed to compensate for the emissions from other sectors, and to evaluate the effect of such a requirement on the system composition. These cases are summarised in Table 1. All cases were applied to each of the three modelled regions. A Monte Carlo analysis on sensitive parameters was also conducted to assess the robustness of the results [20]. Methodology and results from the sensitivity analysis is shown in Appendix B.

2.4. Evaluation parameters

In this work, the value of biomass, the variable renewables (vRE) share, and the total system cost are evaluated for different levels of biomass availability. The value of biomass is here taken as the marginal cost of the biomass constraint, as provided by the cost-minimisation model, and the vRE share is the share of the annual electricity demand supplied by wind and solar power. The biomass availability (*BA*) in region *i*, as applied here, is given by:

$$BA_i = \frac{B_i}{D_i},$$

where B_i is the upper limit on the total energy content of biomass available for electricity generation, i.e., the primary energy in the biomass, in any biomass or electricity conversion unit in region *i*. and D_i is the total annual demand for electricity in region *i*.

The results for the *negative case*, for which a certain amount of biomass is required to meet the constraint of minimum negative emissions, is presented in an alternative form, *negative**, for which BA_i^* is given by:

$$BA_i^* = \frac{B_i - B_i^{neg}}{D_i},$$

where B_i^{neg} is the biomass energy content required to meet the constraint of the minimum level of negative CO_2emissions. Biomass is modelled with zero cost in order to estimate its system value.

Table 1
Cases considered in this study.

	Net emissions	CCS available	Flexibility measures
Base	0	Yes	Yes
NoCCS	0	No	Yes
NoFlex	0	Yes	No
Negative	−10% of Year 1990level [a]	Yes	Yes

[a] The negative emissions have been allocated in relation to the electricity demand.

3. Results

The electricity mixes when cost-optimising the *base cases* for different levels of biomass availability are given in Fig. 1. In the absence of biomass, measures to complement wind and solar power are expensive, so nuclear power may be important from the economic point of view. At low availability of biomass in the regions ES3 and HU, the vRE shares increase with complementing generation from the efficient use of biomass in different CCS plants, which opens an emissions space. The emissions space is initially used for NG CCS and thereafter, for natural gas closed cycle gas turbines (NG CCGT) at higher levels of biomass availability (the latter results in more than a doubling of the amount of flexible electricity, as compared to biomethane CCGT). At a biomass availability of about 20%, biomethane CCGTs start to play a role in all three regions, which is also the point at which the vRE share starts to stabilise. The gasifier choice is for all cases and regions the one that has only biomass as input, i.e., option (i). In the region IE, flexibility from biomass reduces the vRE share already at low biomass availability, since it can replace more expensive variation management strategies.

The system value of biomass relative to biomass availability is shown in Fig. 2. The overall trend is similar for all scenarios and regions: a high initial value that drops rapidly until 15%–25% biomass availability is reached and declines slowly thereafter. In the *base cases*, the biomass value is in the range of 150–180 €/MWh_{th} at 1% biomass availability, although it declines to about 24 €/MWh_{th} at 15%–25% biomass availability. The high initial value of biomass reflects the need for the zero-emissions systems to supply occasional hours of high net load, i.e., load that is very expensive to cover through wind, solar or base-load generation. The highest biomass values are seen in the *noFlex case* in region IE, which has a high share of wind power resulting in a substantial need for flexibility. With CCS available, the biomass is combusted in biomass-steam units with CCS (biomass CCS), thereby enabling the usage of NG CCGT plants to meet the electricity demand at high net load hours, as shown in Fig. 1. For biomass availabilities up to about 20%, the increased availability of biomass provides natural gas-fuelled flexibility, which in turn increases the deployment of

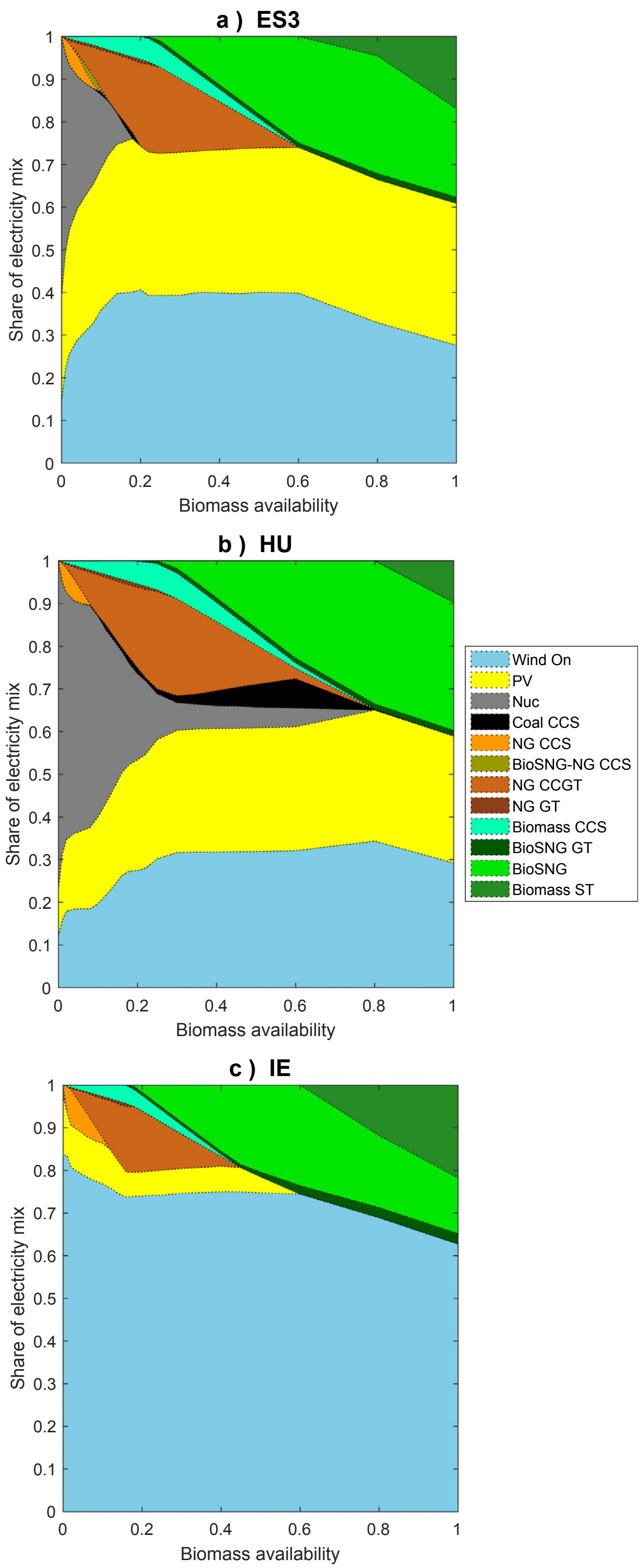

Fig.1. The electricity mixes for different levels of biomass availability for the three regions in the base case.

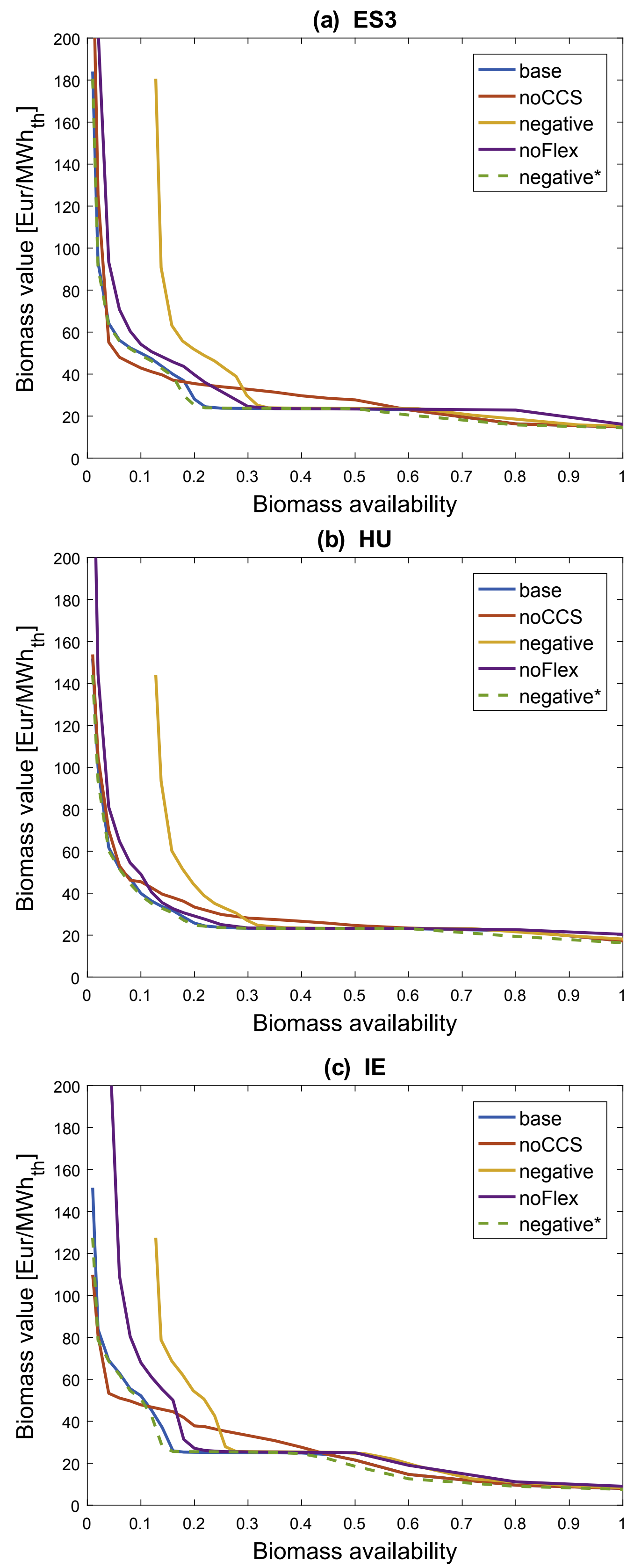

Fig.2. Biomass value at different biomass availability levels for the four scenarios. The green line represents the case "negative*", where the biomass needed for negative emissions is excluded from the availability, i.e., the curve is shifted.

variable renewables and the full-load hours of the biomass CCS units. Beyond 20% biomass availability, the biomass is instead gasified and combusted in CCGTs or open cycle gas turbines (GTs) without CCS. As biomass steam power plants (biomass ST) are integrated, the biomass value drops to about 22 €/MWh$_{th}$, and the systems are supplied by renewables only.

The *noCCS case* differs from the other cases in terms of technology choices. In the absence of the carbon storage option, biomass is deployed as biomethane in CCGTs and GTs already at low biomass availability. This technology option provides less electricity, and therefore less flexibility, per unit of biomass, as compared to the CCS options, which implies that the value of the biomass in the *noCCS case* is lower at low biomass availability, as compared to the other cases, and is also reduced at a slower rate as the biomass availability increases. The value of the biomass in the *noCCS case* is for a significant interval of biomass availability in each region higher than that in the *negative case*, which has a relatively high value of biomass, given that 10% negative emissions is required. However, at high biomass availability, the biomethane and biomass technologies without CCS are the preferred technological options for all the cases investigated, and the biomass values of the *base case* and *noCCS case* coincide.

In the *negative cases*, a biomass availability of 11.7% is needed to satisfy the goal of 10% negative emissions, which means that the model cannot choose to use less biomass. The *negative* case*, in which biomass availability is shifted to exclude this minimal level of biomass from the biomass availability, has a biomass value that is very similar to those for the *base case* in all three regions. Thus, biomass CCS that is deployed to realise negative emissions neither reduces nor increases the value of flexibility within the electricity system. While the biomass CCS can be flexible at certain hours, due to the high investment cost it needs rather many full-load hours over the year in order to be economically feasible. Therefore, biomass CCS does not confer any significant amount of cost-effective flexibility. As expected, lacking flexibility measures (the *noFlex case*) increases the value of biomass, and the effect is rather strong until about 20%–30% biomass availability, implying that batteries, DSM, and hydrogen storage can provide some of the flexibility that biomass-based generation offers.

Fig. 3 gives the cost-optimal share of vRE relative to the availability of biomass for the cases investigated. In regions ES3 and HU, an increase in biomass availability at low biomass availability increases dramatically the vRE share. The reason for this is that the cost-optimal electricity systems in these regions are dominated by nuclear power at low biomass availability, and this nuclear power can be replaced by a combination of wind or solar generation and a flexible complementing technology when biomass is available. In the IE region, the good conditions for wind power together with hydrogen storage, flow batteries, and DSM result in a very high share of wind power in the electricity mix even without biomass. At low biomass availability, where biomass supports vRE in ES3 and HU, it reduces the share of vRE in IE.

For a biomass availability >20%, any further increase in biomass availability has a weak impact on the vRE share for all cases that include CCS as an option. Biomass CCS and NG CCGT, which come into the generation mix at low levels of biomass availability, are exchanged for biomethane CCGTs in this interval. The gas-gas replacement action does not change the flexibility provided by biomass. However, since the biomethane CCGTs do not need any negative emissions (unlike NG plants), the removal of biomass CCS following gas-gas replacement gives slightly more scope for vRE.

The *negative case* and the *noCCS case* require a much higher biomass availability to achieve high shares of vRE, as compared to the other cases. In the *noCCS case*, the available technology options require more biomass per unit of flexibility provided, whereas in the *negative case*, a certain amount of biomass is reserved to create negative emissions. However, if only the biomass remaining after the constraint on negative emissions is fulfilled is considered (*negative* case*), the vRE share is similar to that in the *base case* for

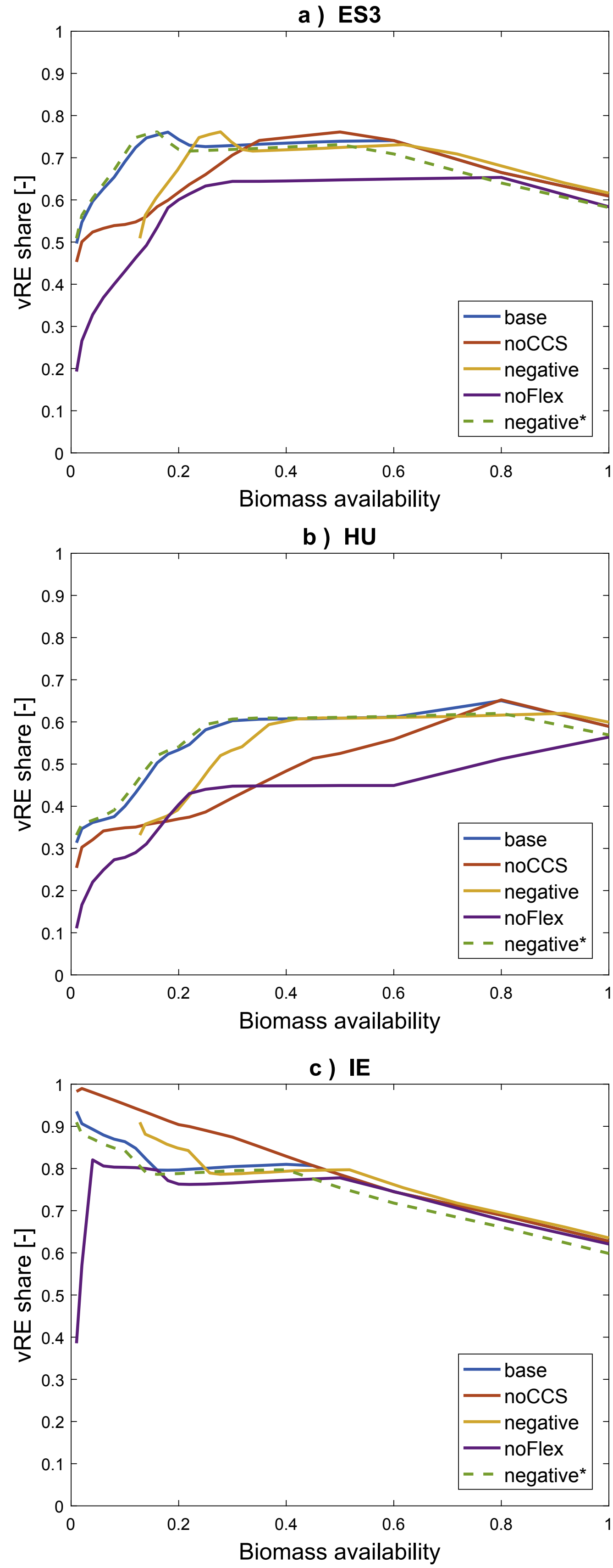

Fig.3. The vRE share as function of the biomass availability levels. The green line represents the scenario "negative*", where the biomass needed for negative emissions is excluded from the availability, i.e., the curve is shifted.

all the regions.

The *noFlex case* gets a much lower optimal share of vRE. This effect is particularly evident in HU and ES3, which have high shares of solar PV strongly supported by DSM[10]. The storage capacities are shown in Fig. 4, where hydrogen storages of up to several hundred GWh are optimal with low biomass availability in several regions and cases, and battery storage capacities of up to 20 GWh are seen in ES3. The batteries in ES3 are, similar to the hydrogen in IE, not part of the cost-optimal system at high biomass availability. The storage capacities are totally phased out by flexibility from biomethane before the model chooses to invest in biomass steam power plants. The share of electricity which is (re)generated in fuel cells (via electrolysis of electricity and hydrogen storage) is shown in Fig. 5. The need for long-term storage in the form of hydrogen storage is highly influential in IE, where wind power is the dominating generation technology.

Fig. 6 gives average electricity generation cost relative to the biomass availability. The cost ranges from 90 to 50 €/MWh and is generally lower in the region IE due to the good wind conditions. It follows from the high biomass value at low biomass availability in Fig. 2 that an increase in biomass availability has a strong potential to reduce the total system cost at low biomass availability, as seen in Fig. 6. This impact is gradually reduced with increasing biomass availability. Biomass has a weaker ability to reduce the total system cost at low biomass availability if CCS is not allowed (compare the *base case* and the *noCCS case*), since the emissions space from negative emissions cannot be used for generation from fossil fuels. To deploy biomass directly in steam boilers or in biomethane CCGTs, as in the *noCCS case*, does not unlock complements to vRE as efficiently as the biomass CCS and NG CCGTs (see Fig. 3). If negative emissions are required, a higher biomass availability needs to be attained to reduce the initial, high total system costs.

Without access to DSM, batteries, and hydrogen storage (the *noFlex case*), the total system cost is substantially higher than that for the *base case*. The rate of reduction in total system cost with biomass availability is almost the same for the *noFlex case* as for the *base case* in ES3 and HU, indicating that the flexibility provided by biomass is equally valuable with or without these flexibility measures. In IE, however, the flexibility from biomass becomes very important to unlock low-cost wind power at low biomass

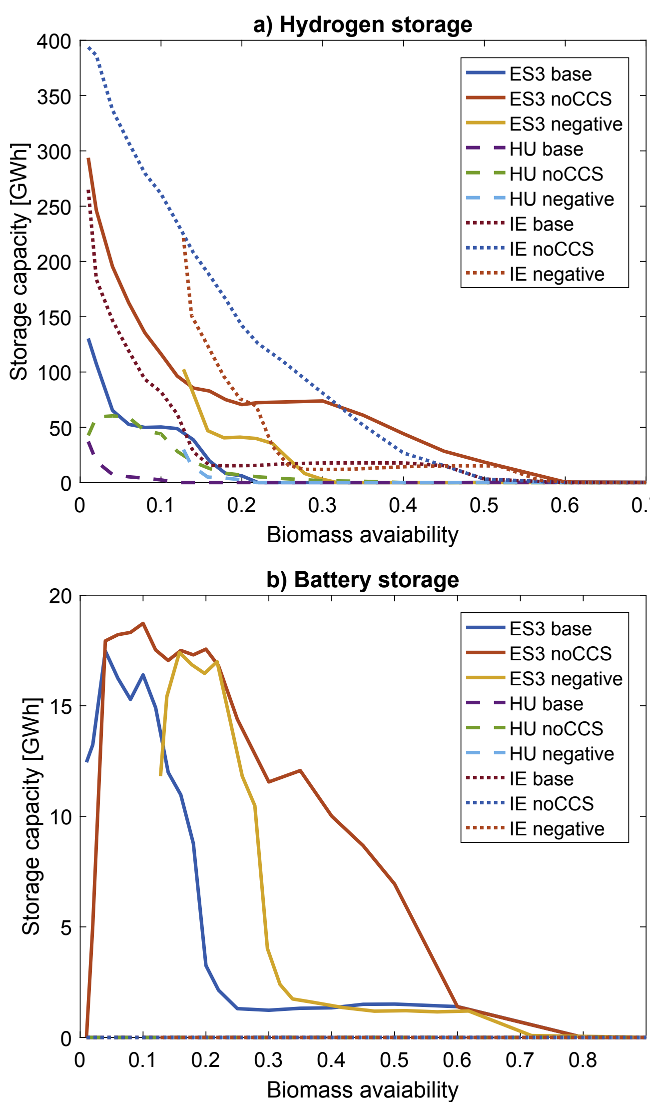

Fig.4. Storage capacities of; (a) hydrogen; and (b) batteries.

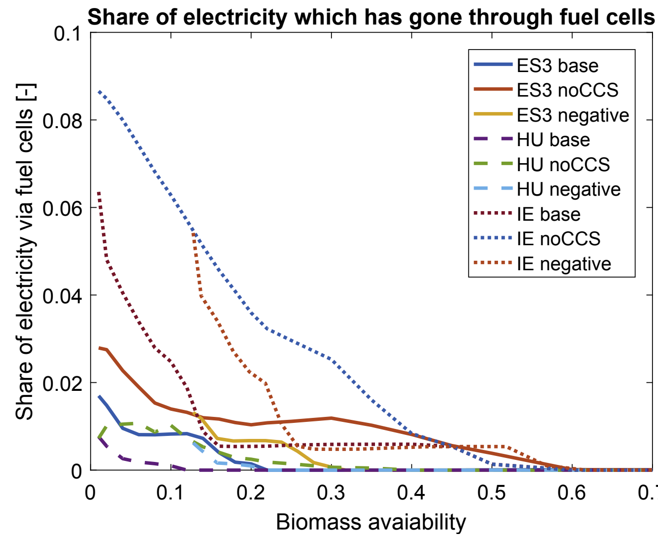

Fig.5. Share of electricity that is (re)generated in fuel cells.

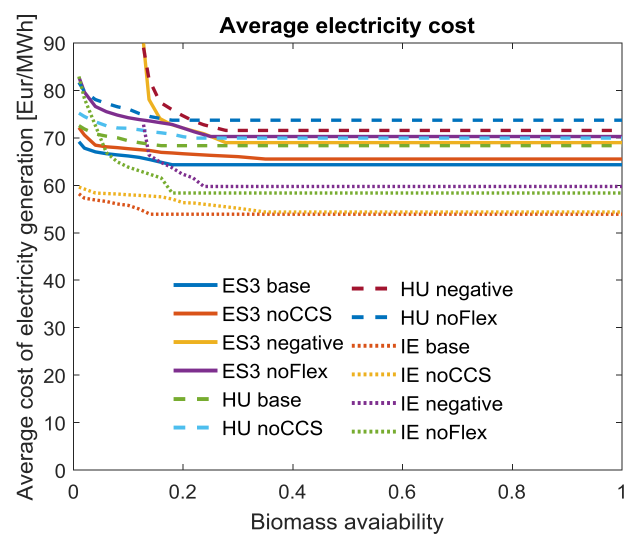

Fig.6. Average electricity generation cost for each case and region. The biomass cost is included by multiplying the marginal value of biomass to the biomass usage until the marginal biomass value reaches 30 €/MWh$_{th}$ after which the cost is set constant.

availabilities in the absence of other variation management strategies (*noFlex case*). It should be borne in mind here that we model biomass at zero cost, so the total system cost continues to decline as more biomass becomes available. In reality, biomass would only enter the system up to the point where its value becomes equivalent to its cost, this point is set to 30 €/MWh_{th} in Fig. 6.

4. Discussion

Although this work provides important insights into the interactions among wind power, solar PV, and biomass, there are several limitations to this study. The regions that we studied are considered in isolation. The addition of trade with neighbouring regions would increase the possibilities for managing variations and for sharing investments. Thus, trade is likely to lower the total systems cost and the value of biomass, especially if trade with regions with hydropower is enabled. However, as the amount of hydropower available is limited, this would not change our findings fundamentally. Trade could then lead to higher vRE shares at low biomass availabilities and a reduced need for base load in the form of nuclear power or flexible complements, such as natural gas CCGTs.

The model does not consider the existing capital stock. Similarly, the historical CO_2 emissions and emissions from other parts of the energy system are not considered. Depending on the investment pathway in the overall energy system, there may be little scope for any fossil CO_2 emissions or too little biomass to compensate for them.

Furthermore, as this case study is applied to regions in Europe, the effectiveness of solar power is lower in our study than in many other regions of the world. However, due to more regular diurnal variations, solar power is more easily managed by alternative strategies, such as short-term storage rather than biofueled complements. Thus, the qualitative findings in this work are expected to hold for wind-dominated regions but may be different for regions closer to the Equator or in regions with large differences in seasonal wind patterns.

An option that might be of relevance for low biomass availability but that is not considered in this work, is to capture and store CO_2 from the gasification process. By allowing the use of natural gas corresponding to the amount of CO_2 stored, this could maximise the yield of carbon-neutral methane from the biomass without the need to introduce additional hydrogen to the gasification process. CO_2 is currently used in different processes in the gasification process, e.g., as an inert gas to prevent the dry biomass from igniting during storage. The amount of CO_2 that can be utilised for CCS in the gasification process is, therefore, uncertain.

As the biomass is included without an associated cost in this work, the system continues to change with the biomass availability even if the actual cost of biomass would be higher than its value. The biomass value can be compared to the bioenergy index PIX (Pellet Nordic Index), which has remained rather stable within the range of 26–31 €/MWh_{th} over the past years [21]. This cost would intersect with the biomass value at between 15% and 20% biomass availability for flexibility.

5. Conclusions

Biomass represents one possible complement to variable renewables that could help to manage variations and create a zero-emission electricity system or even enable negative emissions. However, it remains uncertain as to how much biomass can be grown sustainably and how much of it will be needed for other uses, e.g., feedstock. This work investigates the value of biomass in the electricity system, the choice of technologies for biomass deployment, and the effect of biomass availability on variable renewables.

We use a regional green-field model that is specifically designed to account for variability to identify the least-cost electricity system composition and operational parameters. Three European regions, representing different resource conditions for wind and solar PV, are assessed while the availability of biomass for power purposes is varied.

From the present work, we draw the following conclusions:

- Biomass has a high value for the electricity system if the biomass that is available to the electricity system corresponds to less than 20% of the annual electricity demand in primary energy terms.
- If only the emissions in the electricity sector are regulated, BECCS in combination with natural gas plants represents the cost-effective complement to varying renewables, assuming that the availability of biomass in the electricity system is low or the biomass price is high for other reasons.
- At low biomass availability, access to additional biomass has a strong impact on the share of wind and solar power in the electricity system in regions with low-to-moderate conditions for wind and solar power. Furthermore, regions with good conditions for wind and solar power rely on biomass for a high share of wind and solar in the absence of other variation management strategies, such as demand-side management, hydrogen storage, and batteries.
- Electricity production in BECCS units driven by the need to achieve negative emissions increase the total system costs and reduce the share of wind and solar power if such production limits the amount of biomass available for flexibility in the electricity system.

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Appendix A. Data

Table A.1 gives the investment and variable costs for the electricity generation technologies considered in the model. The investment costs and fixed operational and maintenance costs are based on those given in the IEA World Energy Outlook 2016 [22], with the exception of the costs for onshore wind power, which are based on the costs presented by Monéet al. [23], in conjunction with a yearly learning rate of 0.4%. In the model, annualised investment costs are applied assuming a 5% interest rate. Technology learning for thermal generation is included as a gradual improvement in the efficiencies of these technologies, reflected as a reduced variable cost in Table A.1. The variable costs listed in Table A.1 exclude the cost of cycling thermal generation. Instead, the start-up costs and part-load costs are included explicitly in the optimisation. The start-up costs, part-load costs, and minimum load level applied here are based on the report of Jordan and Venkataraman [24], in which all the technologies that employ solid fuels use the cycling costs given for large sub-critical coal power plants. However, in the present work, the start-up fuel is biomethane rather than oil. The cycling properties of nuclear power are modelled with a start-up time of 72 h and a minimum load level of 90%.

Table A.1
Costs and technical data for the electricity and biomethane generation technologies, as well as for technologies that provide variation management. The variable costs for the bio-based technologies include a biomass price of 30 €/MWh_{th}.

Technology	Investment cost [M€/MW(h)]	Variable O&M costs [€/MWh]	Fixed O&M costs [k€/MW,yr]	Life-time [yr]	Minimum load level [share of rated power]	Start-up-time [h]	Start-up cost [€/MW]	Efficiency [%]
Biomass ST	1.94	2.1	56	40	0.35	12	57	35
Biomass CCS	3.32	2.1	133.2	40	0.35	12	57	27
CCGT[a]	0.90	0.8	18	30	0.2	6	45	61
GT[a]	0.45	0.8	15	30	0.5	0	36	42
CCGT CCS[a]	1.58	0.8	50	30	0.35	12	57	54
Bio-coal CCS (flex)	3.4 (3.6)	2.1 (2.1)	127 (133)	40 (30)	0.35 (0.15)	12 (6)	57 (43)	39 (39)
Nuclear	5.0	0	149	60	0.9	24	2750	33
Solar PV	0.59	1.1	10	25	–	–	–	100
Onshore wind	1.48	1.1	34	25	–	–	–	100
Gasifiers (i-iv)	2.0[b]	–	–	25	0.35	12	43	See section 2.2

[a] Both for NG and biomethane.
[b] Gasifiers are modelled with O&M costs included in the investment cost. All four options are modelled with the same costs due to the lack of data.

The input for gasification is seen in Table A.2 [19].

Table A.2
Input for 1 unit of biomethane from the gasifiers.

	Biomass input	Electricity input	Hydrogen input
Gasifier i	1.39	−0.02	0
Gasifier ii	1.30	0.04	0
Gasifier iii	1.24	−0.02	0.11
Gasifier iv	1.17	0.04	0.10

The wind power generation profiles are calculated for wind turbines of low specific power (200 W/m^2), with the power curve and losses proposed by Johansson et al. [25]. The wind speed input data are a combination of the MERRA and ECMWF ERA-Interim data for Year 2012, whereby the profiles from the former are re-scaled with the average wind speeds from the latter [15,16,26]. The high resolution of the wind profiles from the ERA-Interim data was processed into wind power generation profiles and combined into 12 wind classes for each region, for which the full-load hours (FLH) and the maximum capacities (Cap) for classes 4–12, as well as the offshore wind and solar PV are shown in Table A.3. The wind farm density is set at 3.2 MW/km^2 and is assumed to be limited to 10% of the available land area, accounting for protected areas, lakes, water streams, roads, and cities [27].

Solar PV is modelled as mono-crystalline silicon cells installed with optimal tilt with one generation profile for each region. Solar radiation data from MERRA are used to calculate the generation with the model presented by Norwood et al. [28], including thermal efficiency losses. The full-load hours of solar PV in each region are shown in Table A.3.

The cost and technical data for batteries and hydrogen technologies are shown in Table A.4 [29]. DSM is added exogenously to the system, although the operation of the DSM is endogenous. The fuel properties are shown in Table A.5, and the costs for transport and storage of CO_2 are set to 20 and 5.4 €/ton, respectively.

Table A.4
Costs and technical data for the variation management technologies. The costs for electrolysers are given per MW and the costs of the batteries and hydrogen storage are given per MWh.

	Investment cost [M€/MW(h)]	Efficiency [%]	Fixed O&M costs [k€/MW(h),yr]	Life-time [yr]
Battery, Li-ion	0.15	90	25	15
Battery, Flow (energy)	0.05	70	–	30
Battery, Flow (capacity)	1.1	100	13	30
Electrolyser	1.0	68[a]	24	15
Fuel cell	0.5	60	3 €/MWh	20
H_2storage	0.011	100	–	30

[a] 70% without including compression and storage losses.

Table A.3
Full-load hours (FLH) and maximum capacity (Cap) limits for onshore wind classes 4–12, offshore wind, and solar PV.

Wind class and technology	ES3		HU		IE	
	FLH [h]	Cap [GW]	FLH [h]	Cap [GW]	FLH [h]	Cap [GW]
4	2310	7.1	2370	7.8	–	–
5	2560	6.1	2570	2.4	–	–
6	2790	6.3	2750	1.3	–	–
7	3020	4.6	3070	2.4	–	–
8	3300	1.3	3350	0.2	–	–
9	–	–	–	–	–	–
10	–	–	–	–	4240	0.3
11	–	–	–	–	4640	13.8
12	–	–	–	–	5360	2.1
Offshore	–	–	–	–	5360	…
Solar PV	1770	24.7	1360	12.5	1000	9.6

Table A.5
Costs and carbon intensities for the fuels used in this study.

	Fuel cost [€/MWh$_{th}$]	Carbon intensity [tonne/MWh$_{th}$]
Biomass	0[a]	0.40
Coal (hard coal)	9.8	0.34
Natural gas	34.3	0.21
Uranium	8.1	0

[a] Biomass is modelled with zero cost to estimate more accurately its system value.

Appendix B. Sensitivity analysis

B.1. Monte Carlo analysis on sensitive parameters

A Monte Carlo analysis was conducted on five uncertain parameters: the investment costs for wind power, solar PV, nuclear power as well as wind density and investment costs for hydrogen technologies (electrolyser, storage and fuel cells). All parameters where varied in a uniform distribution, between the values listed in Table B.1, for the base case in ES3 with 20% biomass availability in 528 runs.

Table B.1
Ranges for the parameter values in the Monte Carlo analysis.

	Min–Max	Base value
Wind power	1.0–2.0 M€/MW	1.48 M€/MW
Solar PV	0.3–0.8 M€/MW	0.59 M€/MW
Nuclear power	3.8–7.5 M€/MW	5.0 M€/MW
Wind power density	0.16–0.64 MW/km^2	0.32 MW/km^2
Investment cost factor for hydrogen technologies	0.5–2.0	1 (factor multiplied with the base investment costs)

B.2. Results

The Monte Carlo analysis show that lower costs for wind, solar and hydrogen result in higher vRE shares (>90%; compare to 70% in the *base case*), whereas lower cost for nuclear power or lower wind power density reduce the vRE shares (<35%) and vice versa.

The maximum value of biomass follows a linear function of the investment cost of nuclear power as seen in Fig. B.1 and is set by the opportunity cost for a marginal exchange of vRE and complementing bioenergy for nuclear power. The lower value is kept up by the cost of fossil fuels that can be used with CCS.

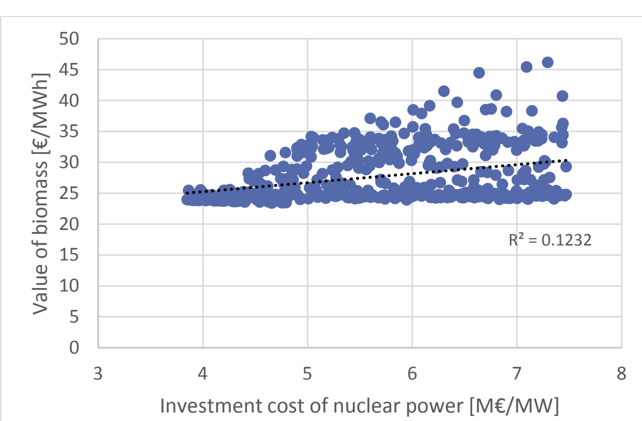

Fig. B.1. The value of biomass as function of the investment cost of nuclear power plants.

The vRE share is plotted against the biomass value in Fig. B.2. When the conditions for vRE are good enough to reach a share above 75% or bad enough to stay below 55%, the biomass value is 23–26 €/MWh$_{th}$. In the range 55–75% vRE share the biomass value vary from 23 to 46 €/MWh$_{th}$. This shows that the value of biomass is low if either wind and solar power or nuclear power is cheap enough to dominate the system.

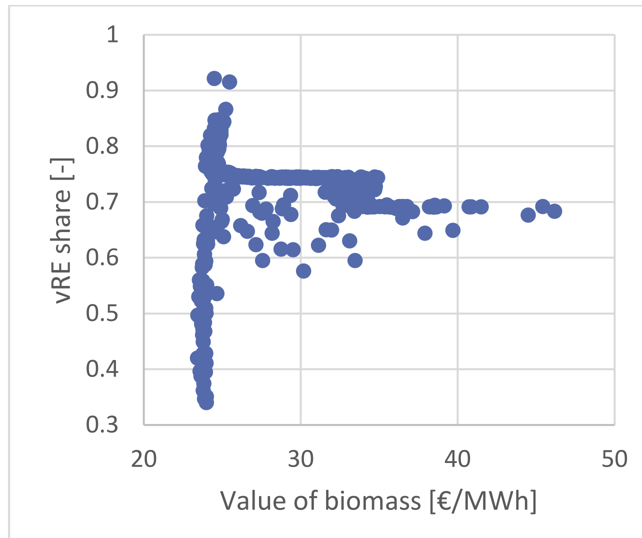

Fig. B.2. The vRE share is plotted against the biomass value for the base case in ES3 with 20% biomass availability.

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