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Optimal localisation of biofuel production on a European scale

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Abstract

This paper presents the development and use of an optimisation model suitable for analysis of biofuel production scenarios in the EU, with the aim of examining second generation biofuel production. Two policy instruments are considered – targeted biofuel support and a CO₂ cost. The results show that over 3% of the total transport fuel demand can be met by second generation biofuels at a cost of approximately 65-73 EUR/MWh. With current energy prices, this demands biofuel support comparable to existing tax exemptions (around 30 EUR/MWh), or a CO₂ cost of around 60 EUR/tCO₂. Parameters having large effect on biofuel production include feedstock availability, fossil fuel price and capital costs. It is concluded that in order to avoid suboptimal energy systems, heat and electricity applications should also be included when evaluating optimal bioenergy use. It is also concluded that while forceful policies promoting biofuels may lead to a high biofuel share at reasonable costs, this is not a certain path towards maximised CO₂ emission mitigation. Policies aiming to promote the use of bioenergy thus need to be carefully designed in order to avoid conflicts between different parts of the EU targets for renewable energy and CO₂ emission mitigation.

Keywords: Biofuels; Bioenergy; Energy system optimisation; Energy policy; CO₂ emissions

1 Introduction

With the aim of mitigating CO₂ emissions, diversifying the energy supply and reducing dependence on imported fossil fuels, the European Union (EU) has set ambitious targets for a transition to renewable energy. The integrated energy and climate change policy adopted in 2008 defines general targets of 20% greenhouse gas reduction, 20% reduced energy use through increased energy efficiency and a 20% share of renewable energy by 2020 [1]. Increased production and use of bioenergy is promoted as a key to reaching the targets [2], as biomass can replace fossil fuels in stationary applications, such as heat or electricity production, as well as in the transport sector. In order to explicitly stimulate a shift to renewables in transportation, the European Commission has, in addition to the overall 20% renewable energy target, set a mandatory target of 10% renewable energy in transport by 2020 [3], with a transitional target of 5.75% for 2010 [4]. Today the total annual energy use in road transport is approximately 3,600 TWh [5]. Of this less than 4.7% consists of renewable energy [6], which is well short of even the 2010 goal.

A number of policy instruments that directly or indirectly affect the production and use of biofuels are today in place in the EU (see e.g. [7, 8]). Targeted biofuel policies such as exemption from or reduction of transport fuel taxes, quotas and blend obligations have a direct effect on the competitiveness and market shares of biofuels. Policy instruments that do not directly target the transport sector, for example tradable CO₂ emission permits and policies targeting renewable electricity production, can also affect biofuel production by stimulating the demand for bioenergy with potentially increased prices as a result.

The last few years have seen an increase in criticism of biofuels, especially regarding first generation biofuels, i.e., biofuels that are commercially available today and that in general use agricultural feedstocks. The criticism is to a large extent related to issues regarding competition with food production and potential negative environmental impact from biofuel production, in particular associated with effects from land use change [9, 10]. Second generation biofuels are biofuels using lignocellulosic feedstock; for example gasification-derived fuels such as methanol, Fischer-Tropsch diesel (FTD) or dimethyl ether (DME), or lignocellulosic ethanol. In general second generation biofuels have lower specific land use requirements than first generation fuels, and since they are based

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on non-food feedstocks, such as various types of waste and forest residues, the competition with food production is considerably lower. Although these biofuels are not yet commercially available much hope is currently placed on them. Studies show that it will likely be necessary to have a significant share of second generation fuels in the EU fuel mix, around 3% of the total transport energy demand, in order to reach the biofuel target for 2020 without substantial interference with other goals (see e.g. [11, 12]).

Second generation biofuel production plants will likely need to be large to reach necessary efficiencies and economies of scale, as discussed for example by Faaij [13]. Large plant sizes increase the necessary feedstock supply area and put significant demands on the supply chain, which makes it necessary to carefully choose the geographic location of the production plants with respect to fuel demand and feedstock locations. Since the potential for biomass is limited, efficient utilisation is necessary. Co-production of several energy carriers as a means to reach increased system efficiency is promoted in the EU cogeneration directive for simultaneous production of electricity and heat [14]. Cogeneration can also be an option for second generation biofuel production, where a considerable part of the feedstock energy not converted into biofuel can be recovered as other energy products, such as heat, electricity, lignin or biogas (see e.g. [15-19]). Co-production thus gives an opportunity for higher total conversion efficiencies, but also puts additional requirements on the determination of the optimal biofuel production plant locations.

This paper presents the development and use of a spatially explicit optimisation model suitable for extensive analysis of biofuel production scenarios in the EU, with the aim of determining and investigating advantageous locations for production of second generation biofuels. The main focus is on assessing how different parameters affect second generation biofuel production regarding costs, plant locations, production volumes and the possibility of reducing global fossil CO₂ emissions. Key parameters to be studied are economic policy instruments affecting biofuel production, such as targeted biofuel support and the cost for emitting CO₂, energy prices, heat delivery opportunities, feedstock costs and availability, and capital costs. The abovementioned 3% share of second generation biofuels for meeting the 2020 target is used as a starting point, with the analysis focusing on boundary conditions that affect the possibility of meeting this goal.

2 Methodology and input data

The optimisation model is used to determine the location and size of biofuel production plants, given the locations of feedstock and energy demand. The model minimises the costs of the complete biofuel supply chain of the studied system, including biomass harvest, biomass transportation, conversion to biofuel, transportation and delivery of biofuel, and sales of excess heat and electricity. Fossil CO₂ emissions are also considered, by including a cost for emitting CO₂, such as a tax or tradable emission permits.

2.1 Model description

The model used in this study is based on the established geographically explicit bioenergy conversion optimisation model BeWhere, which has previously been used in studies of smaller regions or countries, incorporating different biofuel production technologies as well as other bioenergy conversion technologies, such as combined heat and power (CHP) (see e.g. [17, 20-23]). For this study, the model has been further developed to encompass biofuel production in the EU. The BeWhere model has been described in detail by Leduc [24] and Wetterlund [25].

The optimisation model is based on mixed integer linear programming (MILP). It has been developed in the commercial software GAMS [26] and is solved using CPLEX. In order to reduce calculation times, the EU has been divided into eight regions delimited by natural boundaries (water, mountains), which are in turn divided into grid cells with a half-degree spatial resolution (approximately 50 × 50 km). Within each region, the distances between all grid points are computed, in order to be able to calculate transportation costs between any two points. Interchange of biomass feedstock or biofuel between the regions can only take place at defined trade points, situated at major harbour locations or

strategically located border points. Feedstock and biofuel can be traded from one harbour to any other harbour, whereas inland trades can only occur at one specific inland trade point. The trades between the regions are based on the transportation costs of the commodities. No trade taxes are applied between regions or countries.

Figure 1 shows the eight regions with the included trade points. Countries not belonging to the EU (hatched areas) are not considered with respect to energy demand or biomass supply, but trade is allowed through those countries. Malta and Cyprus, both island nations with relatively small populations, have been excluded from the EU for this study.

Figure 1. Region definition and location of the trade points. Hatched areas are non-EU countries and not included in the study.

The model minimises the total cost C_{tot} of the supply chain, which is defined as

$$C_{tot} = C_{supplychain} + E_{supplychain}C_{CO_2}$$

where $C_{supplychain}$ is the supply chain cost, $E_{supplychain}$ the supply chain emissions, and C_{CO_2} the cost for emitting CO_2 .

The supply chain cost $C_{supplychain}$ includes:

- feedstock cost, collection cost and transportation cost to the production plant,
- production plant: set-up and biofuel production costs,
- biofuel transport cost to gas stations,
- income from co-products (i.e., heat, power),
- feedstock/biofuel transportation from one region to another,
- fossil fuel cost for transport.

The supply chain emissions $E_{supplychain}$ include:

- emissions of fossil CO_2 from feedstock and biofuel transportation,
- emissions from additional transport fossil fuel use,
- offset emissions from replaced fossil transportation fuel, electricity and heat.

The supply chain cost is minimised subject to a number of constraints regarding for example biomass supply, biomass/biofuel trade balance, production plant operation balance, and energy demand. For the full mathematic problem formulation, see Leduc [24] and Wetterlund [25].

When running the model, the least costly pathways are selected, from one set of feedstock supply points to a specific production plant, and further to a set of biofuel demand points. The resulting output from the model consists of the location of a set of plants, the different trade flows of feedstock and biofuel between regions, and the cost and CO₂ emissions of the supply chain.

2.2 Biofuel supply chain

2.2.1 Biomass supply

A number of different cellulosic feedstocks could be used for the production of second generation biofuels, for example various woody materials, grasses and agricultural residues. This study only considers forest residues. The average potential supply of forest biomass for use in biofuel production is calculated using the current forest cover, and a yield estimate. The forest cover map has been derived from the global land cover map 2000 [27]. The yield has been derived by using the net primary productivity map from Cramer [28], and linking the net productivity with forest growth functions, which are calibrated using forest increments observed by national forest inventories. The central growth function has the form of

$$TCP_t = TCP_{\max} e^{k \ln^2(t/t_{\max})}$$

and estimates the total carbon production (TCP), until a stand age t , by using the form factor k and the maximum total carbon production ($TCP_{\max}$), which will be reached at the stand age $t_{\max}$. By combining the forest cover map with a biomass map [29], the yield estimates, and the growth function, it is possible to estimate the current age distribution. For estimating the sustainable average harvest potentials, the rotation time, where the average increment will culminate, is selected, and the age distribution of the age classes, until the rotation times are equally distributed. This allows an estimation of the sustainable potential wood increment and harvests for each grid cell. It is assumed that 20% of the total annual wood increment, representing forest residues such as branches, low quality wood or tops from final felling, is available for biofuel production. No distinction is made between different tree species. Figure 2 shows the distribution of forest biomass resources available for biofuel production.

The calculated forest biomass production cost includes cost of felling and forwarding to the forest road, and depends on population density, forest share, land cost level and slope [23], with an average cost in the EU of 17 EUR/MWh. When adding transport costs, this is comparable to current European market prices of forest biomass [30, 31].

Figure 2. Amounts of forest biomass available for biofuel production (TWh/y). Hatched areas are non-EU countries and not included in the study.

2.2.2 Biofuel production

Production of second generation biofuels is still in the development stage, with several different process concepts being investigated for each biofuel production route. In this study, two different biofuel technologies are considered: methanol via gasification and cellulosic ethanol via hydrolysis and fermentation. Electricity and/or heat are co-produced. Surplus heat can either be sold as district heating or, if no heat demand exists close to the plant location, be wasted. Excess electricity is sold to the grid.

For methanol a production process described by Hamelinck and Faaij [32] is considered. In the process, biomass is gasified in an atmospheric indirectly heated gasifier, followed by steam reforming and liquid phase methanol synthesis. Electricity is co-produced in a steam cycle in sufficient quantities to cover the process demands, but with no surplus for export. The potential to recover excess process heat for use as district heating is estimated from data in [33].

For ethanol, the process considered is based on SO₂-catalysed steam pretreatment followed by simultaneous saccharification and fermentation, as described by Barta et al. [34]. Biogas is produced from the wastewater via anaerobic digestion, and incinerated together with the solid waste fractions for production of steam and electricity. Condensation heat is recovered and exported as district heating.

An annual operating time of 8,000 hours is assumed for both technologies. Scale effects have a strong impact on the costs of biomass conversion systems, as discussed by e.g. Dornburg and Faaij [35] and Sørensen [36]. Investments costs are scaled using the general relationship

$$\frac{Cost}{Cost_{base}} = \left(\frac{Size}{Size_{base}} \right)^R$$

where *Cost* and *Size* represent the investment cost and plant capacity respectively for the new plant, *Cost_{base}* the known investment cost for a certain plant capacity *Size_{base}*, and *R* is the scaling factor. An overall scaling factor of 0.7, the average value for chemical process plants [37], is used. Process efficiencies are assumed constant over the entire scale range. The size range is set to 25-100 t_{biomass}/h, which corresponds to approximately 110-450 MW_{biomass}.

Investment costs for new plants are annualised using an assumed economical lifetime of 20 years and an interest rate of 10%, giving a capital recovery factor of 0.11. Table 1 summarises key input data for the technologies.

Table 1. Key input data for the biofuel production technologies. Investment costs have been adjusted to EUR₂₀₀₉ using the Chemical Engineering Plant Cost Index [38].

Parameter	Unit	Methanol ^a	Ethanol ^b
Base plant capacity	MW	357	105
Base investment cost	MEUR	505	143
Operation and maintenance (O&M) cost	EUR/MWh _{biomass}	4.4	8.9
Biofuel efficiency	MWh _{biofuel} /MWh _{biomass}	0.55	0.30
Electrical efficiency	MWh _{electricity} /MWh _{biomass}	0	0.11
District heating efficiency	MWh _{heat} /MWh _{biomass}	0.11	0.40

^a [32, 33]

^b [34]

2.2.3 Transportation and distribution

A network map of roads, rails and shipping routes is used to calculate transportation routes and distances *d* between supply areas and production plants, as well as between production plants and demand areas. This has been described in detail by Leduc et al. [23, 24]. Three transportation means for biomass feedstock and produced biofuels are included: truck, train and boat. The resulting transportation routes can consist of any combination of the three transportation means.

Transport costs for logging residues and biofuel reported by Börjesson and Gustavsson [39] are used as base costs. Since Börjesson and Gustavsson report transport costs in USD/TJ, heating values and moisture contents of feedstocks and biofuels are used to estimate the transport costs for other energy carriers. The transport costs are also adjusted to account for currency development. The resulting transport costs are presented in Table 2.

All gas stations are assumed to be able to handle biofuel distribution, after certain alterations to the existing equipment. The dispensing costs for the two biofuels are assumed equal, at 0.86 EUR/MWh [24].

Table 2. Transport costs in EUR/MWh for feedstock and biofuels, where d is the transport distance in km. Adapted from [39].

Energy carrier ^a	Truck	Train	Boat
Forest residues	$1100+24.9d$	$2330+3.47d$	$2680+1.42d$
Methanol	$441+9.77d$	$1360+2.11d$	$1480+0.473d$
Ethanol	$328+7.26d$	$1010+1.57d$	$1100+0.351d$

^a Forest residues are assumed to have a heating value of 5.13 MWh/t (LHV, dry feedstock) and a moisture content of 50%. Heating value of methanol is 5.52 MWh/t, and of ethanol 7.44 MWh/t [40].

2.3 Energy demand

2.3.1 Transport fuel demand

The total energy demand in road transport in the EU is currently around 3,600 TWh/y, with an estimated increase to over 4,000 TWh/y in 2020 [5, 41]. If the entire available quantity of forest residues presented in Section 2.2.1 was to be used for production of second generation biofuels, 3-6% of the total transport fuel demand in 2020 could be covered, depending on biofuel conversion technology.

In this study, the projected transport fuel demand and population for 2020 are used as basis [41]. The national demand (given in Table A.1 in Appendix A) is downscaled based on grid point population [42], with the demand per capita assumed equal in all grid points of each country. Figure 3 shows the spatial distribution of transport fuel demand. When executing the optimisation model, any fuel demand not met by biofuel is covered by fossil transport fuels.

Figure 3. Transport fuel demand (TWh/y) [41]. Hatched areas are non-EU countries and not included in the study.

2.3.2 District heating demand

Data on district heating in the EU has been obtained from Werner [43] and Egeskog et al. [44]. No data on individual district heating systems has been collected. Instead the total national district heating demand has been downscaled under the assumption that the district heating demand is proportional to the population of each grid point. The heat that could be replaced by the heat from biofuel production depends on a number of highly system-specific factors, such as heat load, current production mix and age structure of the existing heat production plants. Here the district heating systems are described on a nationally aggregated level, with the heat delivered from the biofuel production plants assumed to displace heat corresponding to a heat mix specific to each country. As discussed by Knutsson et al. [45], analysis on an aggregated level can be acceptable when the main focus is not to describe detailed impact on the district heating sector, as this approach significantly reduces the data collection burden. Since the aim of this study is to give a broad view of the potential in EU for domestic biofuel production, an aggregated approach was considered sufficient.

It is assumed that all existing fossil heat, from CHP plants as well as from heat-only boilers, can be replaced by heat from the biofuel production plants. As shown by Werner [43], there is a substantial potential for expansion of the European district heating systems, by replacing fossil fuels used for heating. In total a doubling of the current district heating load could be achieved by 2020. Here this entire expansion potential is also assumed available as a heat sink for heat from the biofuel production plants. A simplified heat load duration curve is applied, with the year divided into three seasons of equal length. To accommodate for variance in annual load distribution at different latitudes, three different load profiles are used, of which one represents the northern EU countries, one represents the central, and one represents the southern countries.

The heat distribution distance limit is set to 50 km. Costs for investments in district heating equipment, such as pipes, pumps or heat exchangers are not included.

Figure 4 shows the distribution of the available heat load, with Table A.1 in Appendix A summarising the national heat loads. For more details, see [25].

Figure 4. Available district heating load (TWh/y) [43, 44]. Hatched areas are non-EU countries and not included in the study.

2.4 CO₂ emissions

The cost of emitting fossil CO₂ is internalised in the model, by including the possibility to apply a CO₂ cost to the supply chain emissions. The cost could for example be a CO₂ tax or tradable emission permits. Emissions from transportation of feedstock and biofuels, as well as emissions from displaced fossil energy carriers, are considered.

Produced biofuel is assumed to replace fossil transportation fuels at a 1:1 energy ratio. Thus each MWh of produced biofuel displaces 282 kg of CO₂ [46]. Potential country-specific differences in CO₂ emissions from transport fuels are not considered. Concerning heat, all fossil district heating, as well as the share of the fossil fuel-based heat that could be replaced by district heating, is considered. Thus, heat delivered from the biofuel production plants is assumed to displace heat corresponding to country-specific fossil fuel heat mixes. The CO₂ emission factors range from 254–425 kg_{CO2}/MWh, with high emission factors for countries with a high share of coal based heat, and low for countries with more natural gas in the heat mix. Country-specific CO₂ emission factors for heat are given in Table A.1 in Appendix A.

For electricity it is assumed that a net surplus of electricity affects the marginal electricity production. The EU electricity market has been deregulated since 2007, with the explicit ambition of the European Commission to overcome remaining obstacles to a fully integrated electricity market, such as transmission capacity bottlenecks [47, 48]. For this reason, a uniform marginal electricity production is assumed for the entire EU, in the form of coal power with a CO₂ emission factor of 723 kg_{CO2}/MWh [49].

CO₂ emissions from the combustion of biomass are not considered, as it is assumed that the CO₂ released when combusting the biomass is balanced by CO₂ uptake in re-growing trees. Marginal effects of drastically increased exploitation of biomass resources could also be included, as this can have significant impact (see e.g. [50]). This is however not included at this stage of model development.

Emissions related to transportation of biomass feedstock and biofuels are given in Table 3.

Table 3. CO₂ emissions from transportation in g_{CO2}/km/MWh of feedstock and biofuels [51].

Energy carrier ^a	Truck	Train	Boat
Forest residues	18.9	9.62	4.95
Methanol	8.77	4.47	2.30
Ethanol	6.51	3.32	1.71

^a Emission factors calculated assuming a heating value of 5.13 MWh/t (LHV, dry feedstock) and a moisture content of 50% for forest residues. Heating value of methanol is 5.52 MWh/t, and of ethanol 7.44 MWh/t [40].

2.5 Energy prices

The energy prices assumed in this kind of study will naturally affect the results to a large extent. Today the energy prices in the different EU member states are highly diversified. Since it is very difficult to predict future prices in all the EU states, country-specific energy prices for 2009 are used in this study, with sensitivity analysis of various energy price parameters being performed.

For transport fuel, average petrol and diesel pump prices (without taxes) from 2009 are used [52]. District heating prices are estimated consumer price averages for 2003 [43], adjusted to EUR₂₀₀₉. It is assumed possible to sell heat at 50% of the consumer buying price. Electricity prices are average end-user prices without taxes from 2009 [53]. Table A.1 in Appendix A shows the country-specific energy prices used.

2.6 Scenarios

Three base scenarios are created, based on different applied policy support. In the first group of scenarios (A), no policy support is included. In the A base scenario (A0), the input data described in Sections 2.2-2.5 is utilised.

In the second group of scenarios (B), a cost for emitting fossil CO₂ is applied. The model is first executed with increasing CO₂ cost in order to estimate what approximate level of CO₂ cost would be needed to meet the 3% second generation biofuel target mentioned in the introduction. This cost is then applied in the B scenarios.

In the third group of scenarios (C), targeted biofuel support is applied, representing for example a feed-in tariff or a reduction in or exemption from transport fuel taxes. Similarly as with the CO₂ cost, the model is executed with increasing level of policy support, in order to find a level which yields a 3% share of second generation biofuels in the EU fuel mix, after which this level is applied in the C scenarios.

For each of the three base scenarios (A0, B0 and C0), parameter variation is performed. Energy prices, heat delivery opportunities, feedstock costs and availability, and plant costs are included in the analysis. In total, 12 different parameter variations are performed, with one parameter varied at a time. The same parameter variation is conducted for each of the three base scenarios, resulting in three groups of scenarios: A1-A12, B1-B12 and C1-C12.

In scenarios 1-2, the price of the biomass feedstock is varied (decreased or increased by 25%), while in scenario 3 it is assumed that only 5% of the annual wood increment is available for biofuel production, representing for example a case with strong competition from other sectors. In scenarios 4-5, the price of fossil transport fuel is varied (decreased or increased by 25%). Correspondingly, in scenarios 6-7, the electricity price is decreased or increased by 25%, and in scenarios 8-9, the district heating price is varied in the same way. In scenario 10 the possibility to sell heat as district heating is removed completely. Scenarios 11-12 concern the high uncertainty related to production plant costs. In scenario 11, the investment cost of all new production plant types is increased by 25%. Finally, scenario 12 regards the uncertainty introduced by using investment input data from different studies, by applying uniform investment and operation and maintenance (O&M) costs for both biofuel production technologies. Table 4 summarises the parameter variation.

Table 4. Parameter variation scenarios for each group of scenarios, where the A scenarios contain no policy support, the B scenarios apply a CO₂ cost, and the C scenarios apply biofuel support. Bold text represents parameters changed compared to the base scenarios. The scenarios are described more in detail in the text above.

Scenario A/B/C	Biomass feedstock	Fossil transport fuel	Electricity	Heat	Production plant costs
0	base	base	base	base	base
1	Price -25%	base	base	base	base
2	Price +25%	base	base	base	base
3	Availability -75%	base	base	base	base
4	base	Price -25%	base	base	base
5	base	Price +25%	base	base	base
6	base	base	Price -25%	base	base
7	base	base	Price +25%	base	base
8	base	base	base	Price -25%	base
9	base	base	base	Price +25%	base
10	base	base	base	No heat demand	base
11	base	base	base	base	Inv. cost +25%
12	base	base	base	base	Inv. + O&M costs harmonised

3 Results

As has been described, the model takes the entire supply chain into account, from feedstock to end energy users. In cases where the use of biofuels is more economical than fossil transport fuels, biofuel production plants will be included in the solution, using the least costly pathways from supply to demand. The resulting output from the model consists of the location of a set of plants, biofuel production characteristics, the different trade flows of feedstock and biofuel between regions, and the costs and CO₂ emissions of the supply chain.

The first of the following sections outlines the results regarding the necessary policy support levels in order to reach a 3% second generation biofuel share in the EU, which are then used in the subsequent model runs and analyses. The following sections present and discuss the results regarding biofuel supply costs, biofuel shares, optimal plant locations, trade, and CO₂ emissions.

3.1 Policy support needed to reach 3% second generation biofuels

Figure 5 shows the resulting share of second generation biofuels in the EU transport fuel mix for increasing levels of the two considered support policy instruments; CO₂ cost and targeted biofuel support.

The CO₂ cost needed to reach 3% second generation biofuels is found to be 59 EUR/t_{CO2}, which is used as a basis for the continued analysis (B scenarios). This can be compared to the trading price of emission allowances within the European Union Emission Trading Scheme (EU ETS), which during the last five years has varied from under 10 to over 30 EUR/ t_{CO2}, with a price of around 15 EUR/t_{CO2} during most of 2009-2011 [54]. Comparison to estimates of the actual marginal costs attributed to CO₂ emissions is difficult, as those estimates are highly diversified, ranging from next to nothing to over 100 EUR/t_{CO2} (see e.g. [55, 56]).

The figure also shows that the biofuel support level needed to reach the 3% goal is 31 EUR/MWh biofuel, which is used subsequently in this study (C scenarios). This can be compared to the average tax exemption in the EU which today amounts to 26 EUR/MWh for biodiesel and 48 EUR/MWh for ethanol, with an average value of 30 EUR/MWh [57].

Figure 5. Second generation biofuel share in the EU for increasing levels of CO₂ cost and biofuel policy support. The 3% target has been marked.

3.2 Biofuel supply costs and biofuel share

Since the model minimises the entire system cost, any given demand point can be supplied by either locally produced biofuel, biofuel transported from another production location, or fossil transport fuels, depending on which provides the lowest supply cost. The biofuel supply cost includes the production cost as well as the cost for transporting and distributing the produced biofuel.

In the scenarios without policy support (A scenarios), the resulting second generation biofuel share turned out to be too low to be analysable ($< 0.2\%$ for all scenarios). The inclusion of either a CO_2 cost (B scenarios) or targeted biofuel support (C scenarios) led to significantly higher biofuel shares over all studied scenarios. Figure 6 shows the average biofuel supply cost in the B and C scenarios, in relation to the resulting share of second generation biofuels in the EU transport fuel mix.

Figure 6. Average biofuel supply cost (EUR/MWh) related to second generation biofuel share in the scenarios applying a CO_2 cost (B scenarios) and the scenarios applying biofuel support (C scenarios). The shade of the markers indicates whether a scenario is dominated by methanol or ethanol plants. Note that different scaling of the y-axis is applied in the two graphs.

As mentioned in the introduction, around 3% of the total EU transport energy demand should be second generation biofuels in 2020, in order to be able to meet the 10% target without significant interference with other goals. The results show that with current energy prices and adequate policy support, this goal can be met at a supply cost to consumers of approximately 65-73 EUR/MWh. This can be compared to average EU pump prices in 2009 of around 45 EUR/MWh without taxes, or around 100 EUR/MWh including taxes and duties. Without any policy support, the resulting biofuel share never reaches even a 1% share.

In the figure, the shade of the markers indicates whether a scenario is dominated by methanol plants (dark markers) or ethanol plants (light markers). The dominant type of plant influences both supply cost and biofuel share, with in general a lower biofuel share in ethanol-dominated scenarios, due to lower biomass-to-biofuel conversion efficiency. Ethanol generally becomes more prominent in

scenarios with lower fuel price (scenario 4) and higher electricity and heat price (scenarios 7 and 9), due to the higher co-production of additional energy carriers.

The two studied policy instruments affect the biofuel production in different ways, which is reflected in the analysed scenarios. The inclusion of a CO₂ cost (B scenarios) does not directly affect the cost of producing or supplying biofuel. Instead, it makes biofuel production competitive to fossil energy carriers due to displacement of CO₂ emissions. For this reason, inclusion of a CO₂ cost stimulates ethanol production, as the substituted CO₂ emissions from the co-products are larger than from the biofuel (discussed in more detail in section 3.4). The inclusion of biofuel support, on the other hand (C scenarios), increases the competitiveness of biofuels due to an increased cost for the alternative (fossil transport fuels). This stimulates methanol production, due to a higher biomass-to-biofuel conversion efficiency.

The cost and availability of biomass feedstock (scenarios 1-3) has a large influence on both biofuel share and supply cost, in the B as well as the C scenarios. The fossil fuel price mainly affects the biofuel share, with a high fossil fuel price (scenario 5) resulting in a considerable increase in biofuel production. In the B scenarios this entails a shift towards more methanol and a lower biofuel supply cost, due to a higher total amount of produced biofuel. In the C scenarios there is no shift in technology choice, and a higher fossil fuel price allows for biofuel production to be competitive also at more high-cost locations, which instead gives a higher supply cost.

As could be expected, higher revenue for sold heat leads to lower supply costs, in particular in the scenarios including ethanol production (B scenarios), where the amount of co-produced heat is larger. The revenue for electricity affects the solution only in the B scenarios, since the methanol dominated C scenarios do not have an electricity surplus. The possibility to deliver heat to district heating networks affects both the total number of plants and the type of preferred biofuel production technology, shifting the production from ethanol to methanol when no heat delivery is possible (scenario 10). A higher capital cost (scenario 11) unsurprisingly increases the supply cost and decreases the biofuel share. Harmonisation of the investment and O&M costs (scenario 12), does not affect the results to any significant extent.

With a CO₂ cost applied, the biofuel share is relatively insensitive to changes in other parameters, with the exception of feedstock availability and transport fuel price. With biofuel support, the biofuel share is more sensitive to parameter variations, while the supply cost is less affected than when a CO₂ cost is included. The parameters having the largest effect are feedstock price and availability, fossil fuel price and capital costs.

3.3 *Biofuel production plant locations*

In the 39 studied scenarios (A0-A12, B0-B12, C0-C12), the optimal number of production plants ranges from 0 to 87, with a second generation biofuel share for the EU spanning from 0 to over 4%. Figure 7 shows the location of biofuel production plants in the two policy support base scenarios (B0 and C0), while Figure 8 shows the geographic distribution of the optimal plant locations, grouped by number of occurrences over all studied scenarios. All plants reached the maximum plant capacity of 100 t_{biomass}/h.

Figure 7. Plant locations in the two policy support base scenarios (B0 and C0).

Figure 8. Number of plant occurrences for the studied biofuels over all scenarios.

In general, the plants are located close to where the biomass availability is high. This is especially pronounced for the northern parts of region 1 (Spain), region 6 (Sweden, Finland and the Baltic states) and for the southwest part of region 8 (Austria). While the locations of methanol plants are distributed over large areas of the EU, ethanol plants mainly occur in the northeast regions, where both the availability of biomass and the heat sink potential are good. Since the transport fuel demand is low in large parts of region 6 in particular, not all produced biofuel can be utilised in the production region. Instead biofuel is exported to other regions. Regions with high population densities and low availability of reasonably priced biomass feedstock have little or no production of their own. This includes region 2 (Italy), region 4 (UK and Ireland), and region 5 (Germany, Belgium, the Netherlands and Denmark). Those regions meet most or all biofuel demand with imported fuels, while region 6 acts as a net exporter in a large share of the studied scenarios.

Since the studied biofuel production technologies have a reasonably high co-production of heat, the optimal plant locations are typically located in populated areas. However, in reality not all of those locations are likely to be suitable for large-scale biofuel production, due to high land and biomass prices, as well as to biomass logistics issues.

Figure 9 shows how much biofuel is produced and used in each region in the two policy support base scenarios. As can be seen, a significant part ($> 35\%$) of the total biofuel production in scenarios B0 and C0 originates in region 6, while several of the other regions have considerably higher biofuel use than production (compare black diamonds to columns in the figure). Even though a substantial part of the total production in region 6 is exported to other regions, the biofuel share in the transport fuel mix (unfilled circles in the figure) is still large in region 6 compared to the other regions, as well as compared to the overall biofuel share in the EU of 3%. The figure also shows that region 2, with very low in-region production, still reaches high biofuel shares. The reason is the high fossil fuel price in Italy compared to the price in for example region 4, where no biofuel is used.

For reference, the model is executed with the biofuel demand fixed to a mandatory 3% in each region (also included in Figure 9). As can be seen, the regional distribution of the biofuel production is virtually unchanged from scenario C0, indicating that this is indeed a cost optimal distribution of production plant locations. The used biofuel and the biofuel share, however, change substantially, with large amounts of biofuel being exported from regions 6 and 7, and, to a lesser extent, from region 1.

Figure 9. Produced (columns) and used (black diamonds) biofuel for each region in the two policy support base scenarios (B0 and C0). The circles indicate share of second generation biofuels in the transport fuel mix for each region.

3.4 Biofuel share and CO₂ emission reduction potential

The reduction of fossil CO₂ emissions is one of the main motivations behind policies and targets promoting a transition towards biofuels in the transport sector. In Figure 10, the potential CO₂ emission reduction in the studied scenarios is plotted in relation to the corresponding biofuel share. Unsurprisingly, an increasing biofuel share entails an increasing emission reduction potential. This is more significant in scenarios where ethanol plants dominate, than in scenarios where methanol plants do. The reason is the high conversion efficiency to electricity and heat in ethanol plants, in combination with the in general significantly higher CO₂ emission factors of displaced electricity and heat compared to displaced fossil transport fuels. Consequently, a considerable part of the reduced CO₂ emissions in the ethanol-dominated scenarios can be attributed to the co-products. This indicates that if stationary biomass applications, such as biomass CHP, were included in the model, biofuels might not necessarily show as much benefit from a high CO₂ cost as they do in this study.

Figure 10. CO₂ emission reduction potential (Mt_{CO2}/y) related to biofuel share. The shade of the markers indicates whether a scenario is dominated by methanol or ethanol plants.

4 Discussion and conclusions

The aim of this paper has been to develop a biofuel production localisation model for the EU, and use it to perform investigations of how second generation biofuel production is affected by different parameters, in particular policy instruments and energy prices. Two policy instruments have been considered – a targeted biofuel support in the form of for example tax reduction, feed-in tariffs or green certificates, and a cost of emitting fossil CO₂, in the form of for example a tax or tradable emission permits.

The results show that around 3% of the total demand of energy for transport can be met by second generation biofuels at a supply cost to consumers of approximately 65-73 EUR/MWh, which can be compared to average EU pump prices in 2009 of around 45 EUR/MWh (without taxes). With energy prices comparable to today's prices, however, this demands considerable policy support, either in the form of biofuel production incentives at a level comparable to the tax exemption in place in many EU countries today (around 30 EUR/MWh), or in the form of a cost of emitting CO₂ of around 60 EUR/t_{CO2}. The results also show that parameters having large effect on biofuel costs and production volumes are feedstock availability, fossil fuel price and capital costs.

Northern EU, with good feedstock availability and demand for co-produced heat, shows opportunities to become a key production region for second generation biofuels, with export to other parts of the EU. It can be concluded, however, that in order for all regions of the EU to reach high shares of second generation biofuels, strong incentives will be needed, as the biofuel distribution will otherwise be significantly higher in the production regions than in the import regions.

It can also be concluded that while forceful policies promoting biofuels may indeed lead to a high share of second generation biofuels in the EU fuel mix at a reasonable cost, this is not a certain path towards maximised CO₂ emission mitigation. The two policy instruments included in this study are to some extent both in place in the EU today. The results from this study show a potential conflict of interest between different parts of the overall EU targets of increased use of renewable energy in transport, and decreased CO₂ emissions. Since biomass is a limited resource, policies aiming at promoting its use need to be carefully designed in order not to counteract each other.

A final conclusion is that in order to reach the EU targets, more and improved interdisciplinary cross-sectorial energy system studies will be needed. The model developed and used within this study, could come to constitute a key component for this kind of studies, which makes it highly relevant for policy makers.

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Appendix A

Table A.1. Country-specific input data. Abbreviations: DH = district heating, El. = electricity.

Country	Population (million people) ^a	Energy demand (MWh/capita,y)		Energy prices EUR/MWh			CO ₂ emission factors kg _{CO2} /MWh DH ^f
		Transp. fuel ^a	DH ^b	Transp. fuel ^c	DH ^d	El. ^e	
Austria	8.4	11	2.9	43	31	76	310
Belgium	11	9.9	2.6	45	24	75	275
Bulgaria	6.8	6.3	2.7	41	12	47	397
Czech Rep.	9.9	9.6	5.9	46	21	88	398
Denmark	5.5	9.4	5.1	49	36	69	413
Estonia	1.2	8.8	5.8	43	12	40	354
Finland	5.4	9.2	7.6	49	17	51	425
France	64	8.6	1.8	43	24	49	259
Germany	83	7.5	3.2	44	28	76	318
Greece	11	8.1	0.46	50	18	60	309
Hungary	9.7	6.1	4.0	47	19	91	287
Ireland	4.8	12	1.2	45	14	82	277
Italy	58	9.1	0.80	50	34	81	254
Latvia	2.1	8.4	4.4	45	18	72	298
Lithuania	3.2	6.6	3.8	45	19	68	303
Luxembourg	0.5	61	3.9	46	24	65	276
Netherlands	17	8.4	4.0	46	24	87	279
Poland	37	5.7	4.0	44	16	69	422
Portugal	11	7.8	0.58	49	14	58	322
Romania	20	4.0	2.7	46	12	58	351
Slovakia	5.3	5.2	4.5	45	18	97	304
Slovenia	2.0	14	2.8	43	18	72	355
Spain	46	10	0.52	48	14	68	255
Sweden	9.6	9.9	1.7	42	28	49	394
UK	63	7.8	1.6	41	14	90	261

^a [41]

^b All existing fossil-fuel based district heating as well as replaced fossil fuels used directly for heating [43, 44]

^c Average petrol and diesel pump prices (without taxes) in 2009 [52]

^d Estimated consumer price averages for 2003 [43], adjusted to EUR₂₀₀₉. It is assumed possible to sell heat at 50% of the consumer price

^e Average end-user prices without taxes in 2009 [53]

^f [43, 44, 46]