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DECARBONIZATION POTENTIAL OF ELECTROFUELS IN THE EUROPEAN UNION

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EXECUTIVE SUMMARY

Many European Union (EU) stakeholders expect electrofuels to have a prominent role in the EU's energy future. Also known as "power-to-liquids," "power-to-gas," "e-fuels" and "e-gas," electrofuels can deliver greenhouse gas (GHG) savings compared to petroleum when they are produced using low-carbon electricity. These alternative fuels are increasingly cited as a promising solution for achieving decarbonization of the transport sector because they can be used in internal combustion engines and, unlike most types of biofuels, have low land use impacts. Electrofuels will be incentivized by the recast Renewable Energy Directive (RED II) for 2021–2030 and automaker associations and other stakeholders are advocating for the GHG savings from electrofuels to also count toward vehicle CO_2 standards.

In a prior study (Christensen & Petrenko, 2017), we assessed the economics and GHG performance of electrofuel facilities in EU Member States from the present to 2040. This paper represents an update to that study, focusing on 2030 and introducing a number of changes to improve the relevance of this work for ongoing policy analysis. Our updated economic analysis for electrofuels uses a new, transparent renewable electricity price forecast for all EU Member States. We add a gaseous electrofuels pathway and assess its competitiveness with fossil gas, as well as explore the economics of using direct air capture to supply CO_2 to electrofuel producers instead of industrial point sources. We analyze how the accounting of electrofuels in the final RED II impacts the GHG performance of these fuels and provide policy recommendations for maximizing their climate benefits.

The net climate impact of electrofuels in the EU depends heavily on how they are counted toward the RED II targets. The RED II specifies that the energy content of the renewable electricity input to the electrofuels production process, not the energy content of the final fuel, is counted toward the 32% renewable energy target. Because the conversion efficiency of electrofuels is, at best, around 50%, the RED II effectively counts twice as much energy toward the renewable energy target as the amount of fossil fuels displaced, which is similar to the double counting of waste-based biofuels toward the renewable energy in transport target in the 2020 Renewable Energy Directive. If the 32% renewable energy sources (RES) target in the RED II is only just met (and not exceeded), any production of electrofuels would thus result in a corresponding shortfall in total renewable energy usage in the EU and thus an increase in fossil fuel use. We explore the direct and indirect GHG emission impacts of electrofuels in five scenarios. Scenario 1 represents electrofuel producers with a direct, off-grid connection to renewable electricity installations, and the RES target would be just met in Scenario 1A and exceeded in Scenario 1B. In Scenario 2, electrofuel producers import electricity from the grid, using guarantees of origin (GoOs) to demonstrate the electricity is renewable, and the RES target would be just met in Scenario 2A and exceeded in Scenario 2B. Scenario 2C is identical to Scenario 2A, but electrofuels count toward the renewable energy target on the basis of finished fuel, similar to other transport fuels.

Our findings largely echo those of our previous study: Electrofuels will deliver limited—if any—renewable fuel volumes and GHG reductions in the EU in the 2030 time frame. We find that very high policy support of 2.5 or 3 euros per diesel equivalent liter would be needed to deliver significant volumes of electrofuels. No electrofuels could be produced economically in the EU with less than 1.50 euros policy support. Even at 3 euros per liter policy support, electrofuels would only offset at most around 0.4% of total EU road transport fuel demand in 2030. Grid-connected electrofuel facilities demonstrating renewable electricity consumption through GoOs are more competitive than facilities directly connected to new renewable electricity installations because they can operate

at full production capacity a greater proportion of the time. Gaseous electrofuels in particular are not competitive due to low fossil gas prices; furthermore, using direct air capture CO_2 substantially worsens electrofuel economics. Significant volumes of electrofuels could potentially be produced in the 2040–2050 time frame if very high policy support were to be maintained.

The potential net climate impact of electrofuels is shown in Figure ES-1. Only in a scenario where electrofuels count toward the 32% renewable energy target on the basis of fuel produced rather than input electricity (Scenario 2C) can electrofuels deliver a significant level of GHG reductions, up to 4 million tonnes CO_2e annually by 2030. Even in that case, very high policy support would be needed to achieve those production volumes, which would still only offset 0.5% of projected road transport GHG emissions in 2030 in the EU. The 3 euros per liter policy support necessary to drive significant deployment is roughly equivalent to 1,200 euros per tonne CO_2e abated in this best-case scenario. If electrofuels were allowed to count toward vehicle CO_2 standards, this strategy of emission reductions would cost 300 euros for each gram CO_2 reduction per kilometer. In all other scenarios, we find that electrofuels would not deliver significant GHG reductions.

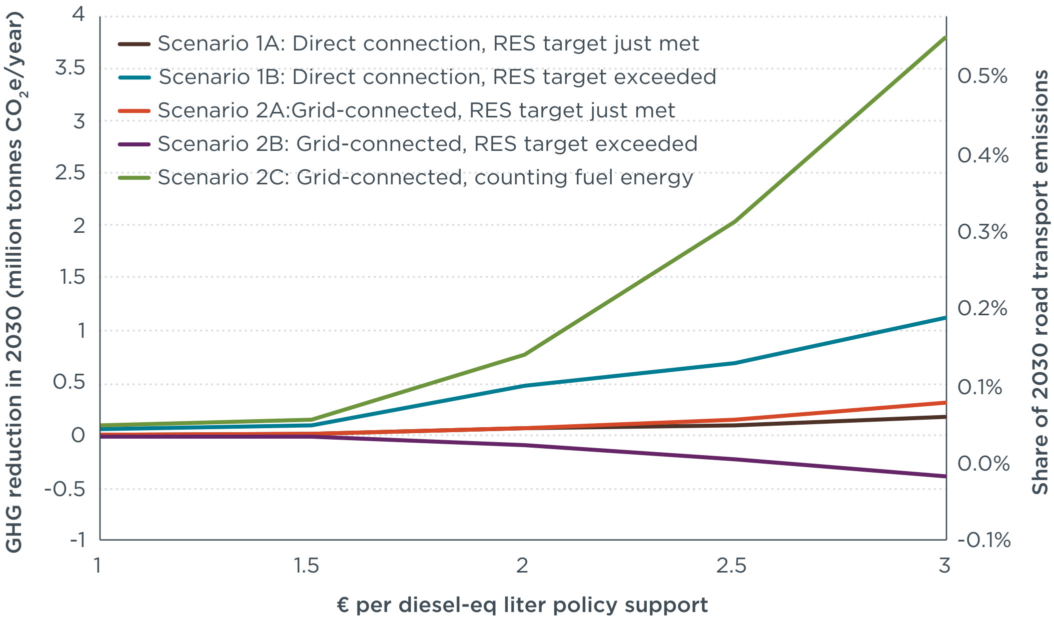

Figure ES-1: Potential GHG reductions in million tonnes CO_2e/year (left axis) and as a share of road transport emissions (right axis) from electrofuels in 2030 in the EU by policy scenario and level of policy support.

Policymakers can make RED II implementation decisions to ensure that electrofuels deliver real GHG reductions. One promising option is to require electrofuel producers to submit GOplus certificates that could demonstrate that the renewable electricity used, whether through a grid connection or a direct connection, has not been directly counted toward the RED II renewable energy target. Such a requirement could be introduced on the basis of excluding electrofuel pathways with high life-cycle GHG emissions, if GOplus certificates are not obtained, or if Member States interpret the RED II accounting clause to mean that the amount of energy in fuel should count toward the renewable energy target. Alternatively, Member States could take measures to exceed the renewable energy target by approximately the same amount as the volume of electrofuels reported.

Another key recommendation is not to allow electrofuels to count toward vehicle CO_2 standards in the EU. Counting the same fuel toward both policies would effectively reduce the stringency of the vehicle standards without delivering additional climate benefits. If measures are taken to ensure that GHG reductions from electrofuels are additional, these fuels can make a modest contribution toward the EU's renewable energy and decarbonization goals.

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INTRODUCTION

Electrofuels are of increasing interest in Europe as a transport decarbonization strategy because they can be produced from clean renewable energy, do not have significant land use impacts, and some types can be used at high blend levels in existing vehicles and fueling infrastructure. These fuels, also known as power-to-liquids, power-to-gas, e-fuels, e-gas, air-to-fuels, and CO_2-based synthetic fuels, are produced by reacting hydrogen from electrolysis with CO_2 in a synthesis reactor to form liquid or gaseous hydrocarbons or alcohols. Electrofuels produced from renewable electricity such as wind or solar power are clearly eligible to count toward the fuel supplier obligation for 14% renewable energy in transport by 2030 in the recast Renewable Energy Directive (RED II; European Union, 2018). The RED II includes a category for "renewable liquid and gaseous transport fuels of non-biological origin" and electrofuels are likely the main potential type of fuel in this class.

Automakers have been highlighting the potential for electrofuels and other low-carbon fuels to contribute to GHG emission reductions in the transport sector, alongside electric vehicles and efficiency improvements. For example, Audi has invested in a gaseous electrofuel production facility in Germany with plans to offset CNG fuel consumption in Audi gas vehicles by injecting gaseous electrofuel into the gas grid (Audi, 2015). Some automaker associations suggest counting the climate benefits from electrofuels toward automaker CO_2 targets. The European Automobile Manufacturers Association has called on the European Commission to explore "setting enabling conditions for alternative fuels—such as gas, biofuels, synthetic fuels, power-to-X technology, electricity, etc.—by exploring the potential benefits of a well-to-wheel approach" (European Automobile Manufacturers Association [ACEA], 2017). Similarly, the Natural & bio Gas Vehicle Association (NGVA Europe, 2017) has stated that it "regrets to see that the European Commission did not take the opportunity to embrace a more comprehensive approach with regard to carbon neutrality, directly considering the role of renewable gas solutions." The ART Fuels Forum, a Commission-organized expert group largely consisting of industry representatives, published a position paper advocating for the GHG reductions from low-carbon fuels to be accounted for in passenger vehicle CO_2 standards (2018).

Low-carbon fuels, including renewable electrofuels, can deliver meaningful contributions to decarbonizing transport alongside other strategies. In an earlier study (Christensen & Petrenko, 2017), we concluded that the climate benefits of renewable electrofuels would be eliminated if the GHG reductions attributable to them were counted toward multiple policy targets. For low-carbon fuels to deliver the intended GHG reductions of decarbonization policies, it is necessary to ensure that any particular quantity of fuel is counted toward only one target. If low-carbon fuels are counted toward vehicle CO_2 standards, they should not also count toward the fuel supplier obligation in the RED II.

Even if double counting of climate benefits from electrofuels does not occur, it is still not clear that these fuels can make a significant contribution toward reducing emissions from the vehicle sector as a whole. In Christensen and Petrenko (2017), we found that a maximum of 413 million liters of liquid electrofuels could be produced annually in the EU by 2030, contributing up to 0.15% of total EU road fuel consumption.

Christensen and Petrenko (2017) provided first estimates of electrofuel potential in EU Member States through 2040. The present study serves as an update to Christensen and Petrenko (2017). Similar to our earlier study, we present projections of electrofuel potential in the EU at varying levels of policy support based on a financial analysis and deployment model, and assess the life-cycle GHG performance of electrofuels in a variety of policy scenarios, accounting for emissions from indirect impacts of electrofuel production on grid operation and renewable energy consumption elsewhere.

We introduce several additions to our earlier work in this study. We add a gaseous electrofuel pathway and separately project potential future volumes of gaseous and liquid electrofuels. In our 2017 study, we found that the cost and potential deployment of electrofuels depend heavily on the price of input renewable electricity. Here, we make new, independent projections of renewable electricity prices and use these to more reliably estimate the total cost of electrofuel production in future decades. We also present new results on the potential for electrofuels using CO_2 from direct air capture instead of industrial point sources. This study updates our conclusions on the GHG performance and overall potential contribution of renewable electrofuels to transport decarbonisation in the EU in 2030. Lastly, we make specific recommendations for EU Member States on accounting of GHG savings from electrofuels in RED II implementation.

The appendix provides rough projections of electrofuel potential over an extended time frame from 2041–2050.

ASSESSMENT OF POTENTIAL ELECTROFUEL VOLUMES TO 2030

This section presents our assessment of liquid and gaseous electrofuel volumes that could potentially be economically produced in 2030. We describe the methodology used in this assessment, followed by the results. As in Christensen and Petrenko (2017), we project electrofuel volumes in each EU Member State and sum the results for the EU. We project potential electrofuel volumes with varying levels of policy support from 1.50–3.00 euros per liter diesel equivalent. Policy support can include incentives for renewable electricity generally as well as incentives for low-carbon fuels. The incentive levels assumed here are meant to represent the total sum of applicable incentives available in any particular EU Member State.

METHODS

Electrofuel production combines two main processes: electrolysis and fuel synthesis. In electrolysis, electricity is used to split water molecules into hydrogen and oxygen. Fuel synthesis converts these products and CO_2 into finished fuels (alcohols or hydrocarbons). There are multiple types of both electrolyzers and fuel synthesis units, and this assessment considers the combinations of several of each. We include alkaline water electrolyzers, proton exchange membrane (PEM) electrolyzer cells, and two variants of solid-oxide electrolyzer cells (SOECs), specifically steam and co-electrolysis. Fuel synthesis technologies included here are Fischer-Tropsch (producing drop-in diesel and gasoline), dimethyl ether (DME) synthesis, methanol synthesis to drop-in diesel and gasoline, and methanation to produce gaseous methane. Further details of these technologies are provided in Christensen and Petrenko (2017).

The production potential of electrofuels is constrained by cost and deployment rate for the foreseeable future. Some electrofuel production technologies are fairly mature and technologically ready for deployment at present. This assessment thus combines a financial model and a deployment model and does not consider technological limitations.

Financial model and capital costs

The costs covered in this assessment include capital costs, operations and maintenance, electrolyzer replacements, country-specific corporate taxes, depreciation, electricity input, CO_2 input, and policy support. The production costs are modeled in terms of energy content for liquid and gaseous electrofuels, then compared with projected diesel and gas prices, respectively.

We build a cashflow model of an electrofuel plant to calculate the net present value (NPV) and the internal rate of return (IRR). We assume that an economically viable facility must have a positive NPV and an IRR of at least 15%. Table 1 lists other key economic parameters used in this analysis.

Table 1. Fundamental economic parameters used in electrofuel financial model

Parameter	Value	Reference
Real Discount Rate	7%	Estimated from the Weighted Average Cost of Capital (WACC) from NREL Annual Technology Baseline Data (National Renewable Energy Laboratory [NREL], n.d.)
Plant Lifetime	30 years (no salvage value)	Brynolf, Taljegard, Grahn,& Hansson (2017)
Construction Time	2 years (75% initial capital in year 1, 25% in year 2)	
Depreciation Rate	Straight line	
Depreciation Rate	5%	
Operations & Maintenance	2% of initial capital costs/year	Brynolf et al., 2017; Giglio et al. 2015

Following Christensen and Petrenko (2017), we assume capital costs decline over time and with increasing facility size (i.e., economies of scale). Assumptions on capital costs and electrolyzer replacement costs and references for most technology pathways are provided in Christensen and Petrenko (2017). For methanation, we assume capital costs are 1.71 million euros and the capacity is 5 MW_e (Brynolf et al., 2017; Götz et al., 2016; Grond, Schulze, & Holstein, 2013; Hannula, 2015; de Bucy, 2016; McDonagh, O'Shea, Wall, Deane, & Murphy, 2018). Electrolyzer and fuel synthesis efficiencies for most pathways are given in Christensen and Petrenko (2017). For methanation, we assumed a fuel synthesis efficiency of 77% (Grond et al., 2013; Brynolf et al., 2017; Mohseni, 2012; Schiebahn et al., 2015; Sterner, 2009; Schiebahn et al. 2013; Tremel, Wasserscheid, Baldauf, & Hammer, 2015; de Bucy 2016).

Electricity prices

Electricity is a major input in electrofuel synthesis. Changes in electricity prices have a large impact on electrofuel economics. This assessment covers electrofuel production using wind and solar electricity because the RED II incentivizes only renewable electrofuels.

We consider two scenarios for electricity supply to electrofuel facilities, with different input prices for each scenario:

» Scenario 1: Direct connection to renewable electricity installations. The price of electricity input to electrofuel facilities is the Levelized Cost of Electricity (LCOE), including some taxes but not distribution and transmission fees, also known as grid fees. Because the electrofuel facility is assumed to not be grid-connected, we also assume the electrofuel plant operates at the capacity factor of the renewable generator.

» Scenario 2: Import electricity from the grid. GoOs would be used to demonstrate that the imported electricity is renewable. Full taxes and grid fees apply. We assume electrofuel plants operate at full capacity with a capacity factor of 0.95.

In Christensen and Petrenko (2017) we used electricity price projections from Bloomberg New Energy Finance (BNEF) for Germany, scaled to other EU Member States by differences in solar and wind capacity. BNEF's projections implicitly included existing incentives for renewable electricity, which are currently substantial in Germany. Our analysis thus also implicitly included substantial renewable electricity incentives. In that study, we presented our results on electrofuel potential with varying levels of policy incentive that are additional to the incentives already included in BNEF's electricity price projections. Because we did not have enough information available to separate out the implied incentives in BNEF's prices, we were not able to analyze the total amount of policy incentives necessary for electrofuels to be cost viable.

In the present study, we address this problem by creating new renewable electricity price projections for EU Member States. The policy support levels may be interpreted as the total amount of support necessary to achieve various degrees of electrofuel penetration. We also aim to provide transparency by detailing our methodology for developing these projections.

We estimated electricity prices as the time series of LCOE for wind and solar systems in the EU from 2018–2080. Although the assessment here focuses on the 2030 time frame, in the Appendix we provide results to 2050. Because we assume electrofuel facilities to have a 30-year lifetime, it was necessary to project electricity prices through 2080. The LCOE is a measure of the average total cost to build and operate a generator over its lifetime divided by the total energy output over the lifetime of the plant. In other words, this measure reflects the minimum price necessary to sell energy to meet a certain IRR. We assume an after-tax IRR of 7% for solar and wind projects, consistent with fully commercialized technologies. The aggregated parameters used to calculate wind and solar electricity cash flows are described in Table 2; we take these from the National Renewable Energy Laboratory's Annual Technology Baseline database (NREL, n.d.). This database includes United States data, however, it is assumed that CAPEX rates for utility-scale solar/wind fluctuate on a global scale; as such, European rates will not differ significantly. It was assumed that the generator system had zero salvage value at the end-of-life and that accelerated depreciation (5-year) was calculated with a straight-line method.

Table 2. Parameters used to calculate the levelized cost of energy for solar and wind projects

Data Description	Solar	Wind
System Life	30 years	30 years
Fixed Operations and Maintenance Costs	11 $/kW-year	50 $/kW-year
Variable Operations and Maintenance Costs	0.002 $/kWh	0 $/kWh
Generator Performance Degradation	-1 % output/year	-0.5 % output/year
Inverter Replacement Cost	100 $/kW (measured as DC output)	—
Inverter Lifetime	10 years	—
Gearbox Replacement Cost	—	15 % of CAPEX rate
Gearbox Lifetime	—	7 years
Blade Replacement Cost	—	20 % of CAPEX rate
Blade Lifetime	—	15 years
Number of Replacement Blades	—	1

Using the LCOE metric as a proxy for the actual generation price represents a balance between completeness and transparency. We implicitly assume that an electrofuel facility obtains electricity from a new wind or solar installation built in that same year. In reality, generation-only electricity prices are a more complicated function of transmission grid dynamics. However, a transparent model that considers the details of grid effects is not available. Figure 1 shows the EU average price trends for solar and wind electricity generation in our analysis. The decline in electricity prices for both technologies is due to an expected decline in CAPEX. Solar and wind generation costs, taxes, and grid fees are also presented in the Appendix. Our projections for wind and solar electricity generation prices are similar to those reported elsewhere (International Energy Agency, 2017).

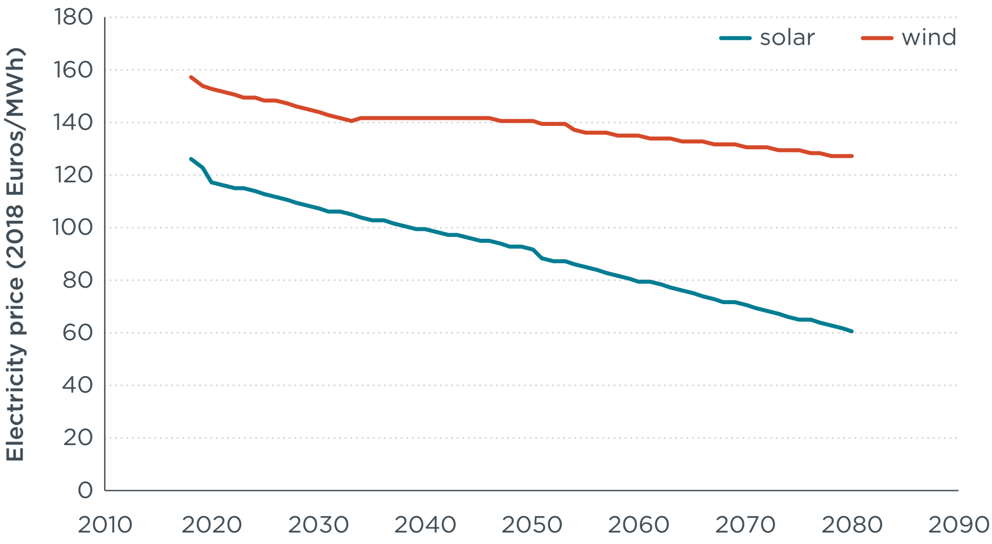

Figure 1. Average cost of solar and wind electricity generation in the EU from 2018–2080.

We calculate taxes and grid fees in each EU Member State as follows. Electricity taxes for each Member State for 2015 are taken from Figure 7 in European Commission report (2016a). We subtracted the share of taxes that are designated for supporting renewable energy and combined heat and power, applying the EU-average share from Figure 5 to the Member State tax rate. This step was taken for consistency in separating out support for renewable electricity, and therefore electrofuels, from other costs. For Scenario 1, we assume 75% of current taxes apply; some Member States exempt self-consumers of renewable electricity, which would apply to an electrofuel producer owning an attached renewable electricity installation, from a portion of taxes (GfK Belgium consortium, 2017). We did not attempt to estimate the proportion of tax reduction in each Member State because the tax treatment of self-consumers of renewable electricity across all Member States is currently changing on an annual basis.

We adjusted grid fees from the network costs shown in Figure 7 in European Commission (2016a) for each Member State. Grid fees are expected to increase in future years as variable renewable electricity penetration increases over time. Variable renewable electricity sources, namely wind and solar, tend to have greater forecast errors than other electricity sources such as coal, gas, and nuclear. This leads to greater balancing costs for increased use of spinning reserves and energy storage, such as batteries. In addition, solar and wind electricity can have higher transmission and distribution costs because these installations can be located further from the electricity grid than, for example, a new coal plant might be. To project the increase in grid fees from 2015 to 2080, we draw on an assessment of balancing, transmission, and distribution costs of increased variable renewable electricity penetration in Germany from Fursenweth, Pescia, and Litz (2015), assuming that the cost analysis performed for Germany in that study would apply similarly to other EU Member States. In reality, the situation is different in every Member State, but a similar type of analysis is not available for all Member States. The balancing and distribution costs for Germany from Fursenweth, Pescia, and Litz (2015) are similar to those projected for the EU in Pudjianto, Djapic, Dragovic, and Strbac (2013) and the Nuclear Energy Agency (2012).

Balancing costs are expected to rise slightly with increasing variable renewable electricity penetration, as more resources are required to correct for forecast errors when those errors apply to a larger share of total electricity generation. To account for this relationship, we relied on a regression between observed and modeled balancing costs and the share of wind power penetration from Figure 23 in Fursenweth, Pescia, and Litz (2015). We assumed the balancing costs from solar power to be half that of wind for all penetration rates, following a finding in Fursenweth, Pescia, and Litz (2015) that balancing costs for solar power are generally half that of wind and in the absence of a solar-specific regression analysis. To estimate balancing costs from this regression, we had to make assumptions on the wind and solar share to 2080. We took projections on EU-wide wind and solar share for 2020–2050 from Figure 38 in the European Commission trends report (2016b). We calculated the 2015 wind and solar share as the ratio of wind and solar electricity generation to total electricity consumption for each Member State from Eurostat (n.d.). We assumed that each Member State would increase its wind and solar penetration from 2015 through 2050 proportionally to its 2015 wind and solar electricity consumption so that on aggregate, Member States would reach the EU-average wind and solar shares in European Commission (2016b) for 2020–2050. We assumed that the increased rate of wind and solar penetration over the period 2040–2050 would continue linearly to 2080. After calculating the increase in balancing costs due to increased penetration of wind and solar separately, we summed these costs to calculate the total increase in balancing costs due to increasing total variable renewable electricity penetration in each Member State. We subtracted our estimated balancing costs for 2015 from the balancing costs for all years thereafter to identify the projected growth in balancing costs in future years.

We took per MWh distribution and transmission costs for solar and onshore wind from Figure 3 in Fursenweth, Pescia, and Litz (2015) and assumed that these costs would remain constant over time. We multiplied these costs by our projected share of wind and solar power in each Member State as described above. Similar to balancing costs, we subtracted our estimated transmission and distribution costs for 2015 from those for all years thereafter. Balancing, transmission, and distribution costs for variable renewable electricity in 2015 are already implicitly included in the network costs we took from the European Commission report (2016a). We thus needed to identify the growth in these costs from 2015 to 2050. We then add balancing, distribution, and transmission costs to 2015 network costs to estimate total grid fees in each year after 2015. We project that grid fees will increase slightly due to increasing renewable electricity penetration. These results are presented in the Appendix.

CO_2 input costs

In addition to renewable electricity, a key input for electrofuel production is concentrated CO_2. CO_2 generally comes from either point sources or direct air capture (DAC). Point sources of CO_2 include flue gases from industrial processes, power plants, or other chemical processing facilities. DAC extracts CO_2 from ambient air through an adsorption-desorption chemical process. Table 3 presents the harmonized capture cost from a number of techno-economic analyses.

Table 3. Costs for capture of CO_2 from different sources

CO_2 source	Capture cost	Year available	Units	Reference
Natural gas power plant	21–64 10–64	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Coal power plant	32–180 10–110	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Petroleum refining/ petrochemical	64–150 32–95	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Cement industry	75–160 32–53	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Iron and steel	53–75 32–64	2028–033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Ammonia production	<21 <21	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Bioethanol/biogas	<21 <21	2028–2033 2038+	2018 €/tCO_2 captured	Brynolf et al., 2017
Biomass w/ carbon capture	55	—	2018 €/tCO_2 captured	Keith, Ha-Duong, and Stolaroff, 2006
Direct air capture	140	—	2018 €/tCO_2 captured	Keith, Ha-Duong, and Stolaroff, 2006
Direct air capture	53	—	2018 €/tCO_2 captured, but does not include regeneration costs of the sorbent	Holmes and Keith, 2012
Direct air capture	90	—	2018 €/tCO_2 captured	Lackner, 2009
Direct air capture	915	—	2018 €/tCO_2 avoided	House et al., 2011
Direct air capture	"Estimates of \$100/tC (\$27/tCO_2) to \$500/tC (\$136/tCO_2) found in the literature for direct air capture are just not believable. Absent a technological breakthrough that departs from humankind's accumulated experience with dilute gas separation, direct air capture is unlikely to be a serious mitigation option until the price on CO_2 is measured in thousands of dollars per tonne of CO_2."			Ranjan and Herzog, 2011
Direct air capture	400–595	—	2018 €/tCO_2 captured, just the energy costs no capital recovery costs included	Ranjan, 2010
Direct air capture	551–742	—	2018 €/tCO_2 avoided	Socolow et al., 2011
Coal power plant	75	—	2018 €/tCO_2 avoided	Socolow et al., 2011

There is a wide range of cost estimates for CO_2 from both concentrated and dilute sources. Recognizing this, we use three different assumptions for the price of CO_2: (1) 34 euros/tCO_2 (\$40/t CO_2), representing capture from a point source, (2) 128 euros/tCO_2 (\$150/t CO_2), representing an optimistic estimate of DAC costs, and (3) 513 euros/tCO_2 (\$600/t CO_2), representing a central cost estimate for DAC. For the purposes of this analysis we assume that all three of these technologies would be available starting in 2018, which likely overestimates electrofuel potential using DAC in particular. We assume these costs (in constant 2018 euros) stay constant over time.

Fuel sale prices

We assume that electrofuels will be sold at the same wholesale price as fossil diesel and gas on an energy equivalent basis. We use the same assumptions and data sources for diesel price projections as in Christensen and Petrenko (2017). For gas, we took a wholesale methane price forecast for the EU from the World Bank (n.d.).

Deployment model

We use the same deployment model described in Christensen and Petrenko (2017).

RESULTS ON ELECTROFUEL POTENTIAL IN 2030

Projected electrofuel volumes in 2030 are shown in Figures 2–5. All results are presented in constant 2018 euros. Modest volumes of both liquid and gaseous electrofuel could be produced via direct connection to renewable electricity installations with point source CO_2 (Figure 2). Although we find that gaseous electrofuels have lower production costs, we project lower potential volumes for these fuels than liquid electrofuels because it is more difficult to compete with low-priced fossil gas. In almost all the scenarios and conditions we investigated, liquid electrofuels are more competitive than gaseous electrofuels, so we project higher potential volumes of liquids. We found that no electrofuels would be cost viable with combined policy support levels lower than 1.50 euros per liter diesel equivalent. This result contrasts with our findings in Christensen and Petrenko (2017), in which we projected that very modest potential electrofuel volumes could be viable with as little as 0.75 euros/L in some scenarios. The reason is that in Christensen and Petrenko (2017), we implicitly included substantial existing renewable electricity incentives that were additional to the 0.75 euros/L policy support by using renewable electricity price forecasts from BNEF. In the present analysis, each policy support level includes all incentives for renewable electricity as well as electrofuel production. Because electricity prices constitute most of the total production costs for electrofuels, the increase in our assumed renewable electricity prices has a large effect on the overall economics for these fuels. In this study we find that 3 euros per liter of policy support is necessary to support significant volumes of electrofuels. This finding supports a recent study commissioned by Verband der Automobilindustrie, which reported that electrofuels current cost around 3.20–3.60 euros per liter more than fossil diesel and petrol (Seigemund, Trommler, Schmidt, & Weindorf, 2017).

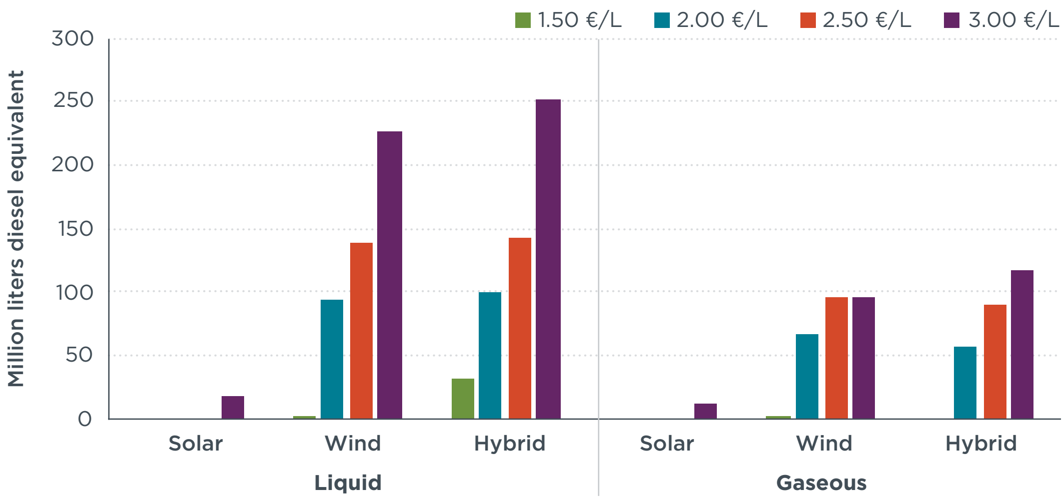

Figure 2. Total EU electrofuel potential in 2030 in Scenario 1 (direct connection) with point source CO_2 (million liters diesel equivalent).

With direct connection, electrofuels produced using wind power are more competitive than using solar power. This is mainly because Sweden has a much higher capacity factor for wind than the capacity factor for solar in any country, and Sweden dominates the total wind-powered electrofuel potential in the EU. Much of the electrofuel potential using solar power comes from countries with relatively high solar capacity factors: Portugal, Spain, and Greece. Electrofuel potential is highest when the direct connection is to a hybrid renewable electricity installation combining wind and solar because the combination slightly increases the effective capacity factor of the electrofuel facility.

DAC of CO_2 significantly increases the total production cost of electrofuels. Even with an optimistic DAC price, potential electrofuel volumes are significantly lower with DAC than when using point source CO_2 (Figure 3). When we assume central DAC costs (in the middle of the range of estimates reported in the literature), almost no electrofuel potential is cost viable in the 2030 time frame.

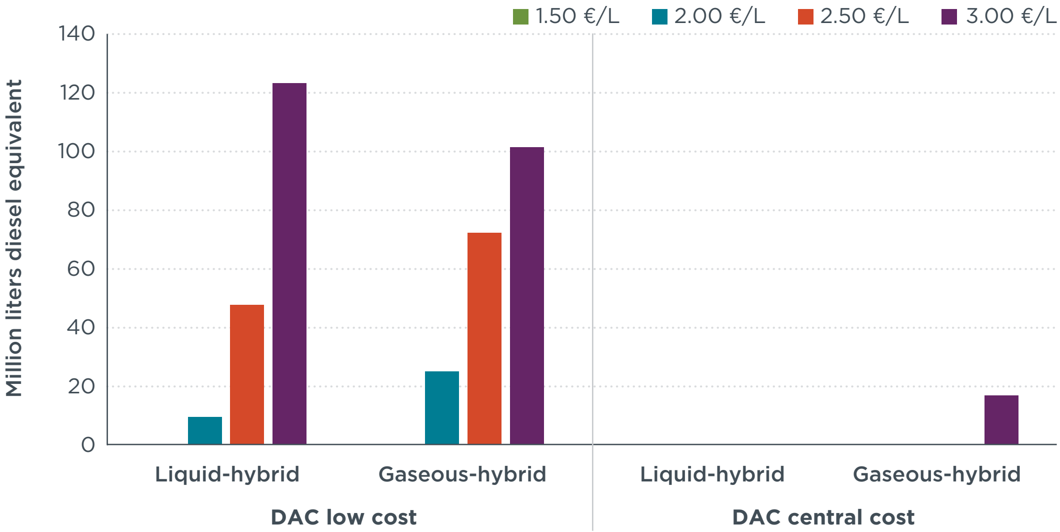

Figure 3. Total EU electrofuel potential in 2030 in Scenario 1 (direct connection) with DAC CO_2 and a hybrid renewable electricity installation (million liters diesel equivalent).

Electrofuel potential is much higher in Scenario 2, where facilities are grid-connected and purchase GoOs to demonstrate that the electricity is generated from wind or solar power, than in Scenario 1 (Figure 4). Although grid-connected renewable electricity prices are higher than with direct connection because they include grid fees and full electricity taxes, this disadvantage is more than offset by the increased capacity factor of grid-connected electrofuel facilities. Grid-connected facilities can operate almost all the time, while facilities powered by direct connection to wind and solar installations are limited by the capacity factor of wind and solar at those locations. For example, the solar capacity factor of Portugal is 0.42, meaning that an electrofuel facility powered by direct connection in that country can only operate at 42% capacity. The increase in capacity factor of grid-connected electrofuel facilities compared to those powered by direct connection greatly improves their economics. Unlike in Scenario 1, electrofuel potential in Scenario 2 is highest when GoOs from solar facilities are purchased. This is because solar power costs per kilowatt hour are projected to decline faster than wind power costs by 2030 due to technological learning. And because grid-connected electrofuel facilities are not limited by the lower solar capacity factors, electrofuel producers can take full advantage of the lower solar power prices in this scenario.

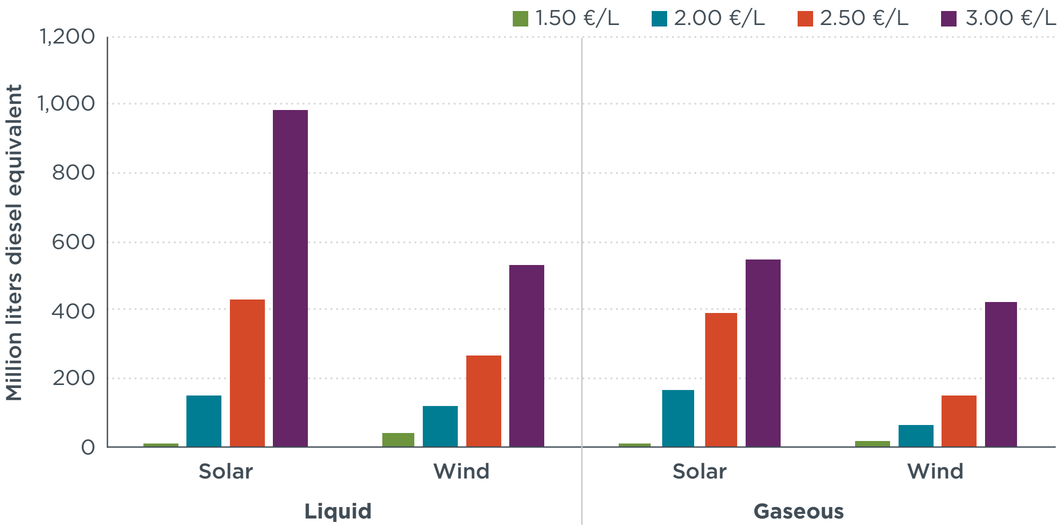

Figure 4. Total EU electrofuel potential in 2030 in Scenario 2 (grid-connected) with point source CO_2 (million liters diesel equivalent).

Similar to Scenario 1, in Scenario 2 the higher cost of using DAC CO_2 significantly reduces potential electrofuel volumes (Figure 5).

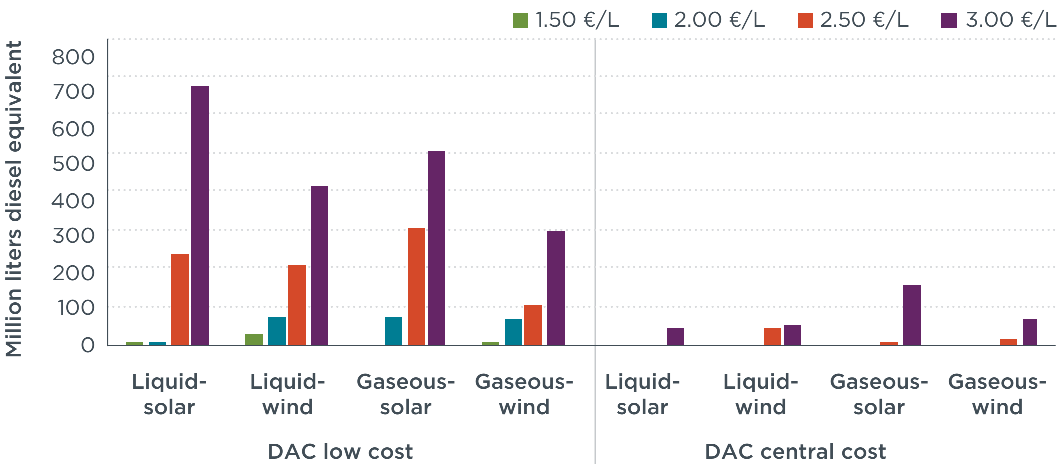

Figure 5. Total EU electrofuel potential in 2030 in Scenario 2 (grid-connected) with DAC CO_2 (million liters diesel equivalent).

Electrofuels are unlikely to displace a substantial share of total road transport fuel in the 2030 time frame. Table 4 shows electrofuel potential from Figures 2 and 4 (using point source CO_2) as a share of projected total road transport fuel from the EU Reference Scenario (European Commission, 2016b). In Table 4, the maximum total electrofuel potential represents the sum of liquid and gaseous fuels produced from hybrid electricity installations in Scenario 1 and the sum of liquid and gaseous fuels produced from solar power in Scenario 2. In Scenario 1 with direct connection to renewable electricity installations, the maximum electrofuel potential is less than 0.1%. Electrofuel potential in Scenario 2 is more significant, especially if solar GoOs are used, and could potentially displace around 0.4% of total road transport fuel in the EU. While this is still a very modest contribution, it represents around 3% of the renewable energy needed to meet the transport target in the RED II. In any case, our results strongly suggest that electrofuels are unlikely to make a significant contribution to the RED II transport target or to fossil fuel displacement in the transport sector more generally in the 2030 time frame. The potential contribution from electrofuels would be even lower if CO_2 from DAC were used.

Table 4. Total EU electrofuel potential as a share of projected total road transport fuel in 2030 in different scenarios with point source CO_2

		Scenario 1 (direct connection)		Scenario 2 (grid-connected)	
		2.00 €/L	3.00 €/L	2.00 €/L	3.00 €/L
Liquid	**Solar**	0.000%	0.006%	0.048%	0.312%
	Wind	0.008%	0.019%	0.010%	0.045%
	Hybrid	0.008%	0.021%	N/A	N/A
Gaseous	**Solar**	0.000%	0.001%	0.014%	0.046%
	Wind	0.006%	0.008%	0.006%	0.036%
	Hybrid	0.005%	0.010%	N/A	N/A
Maximum total potential in EU		**0.013%**	**0.031%**	**0.061%**	**0.358%**

CLIMATE PERFORMANCE OF ELECTROFUELS

Generally, electrofuels offer emission reductions if produced from low-carbon renewable electricity, but if produced from fossil energy sources can worsen GHG emissions compared to petroleum. Electrofuels also can cause indirect emissions, even if produced from renewable electricity. For example, consider an existing solar installation powering a nearby town. If that solar electricity is diverted to new electrofuel production, a new gas electricity generator may be built to meet that town's energy demands. The net impact is that the total use of renewable energy does not increase, but is actually similar to a situation where the electrofuel facility is powered directly by gas. In order to deliver full life-cycle GHG reductions, electrofuels must be powered by *additional* renewable electricity supply. Policies on electrofuels and renewable electricity can drive—or prevent—these indirect effects on electricity generation. Here, we examine the specific case of how electrofuels are incentivized in the RED II.

EMISSIONS ACCOUNTING IN THE RECAST RENEWABLE ENERGY DIRECTIVE (RED II)

Only electrofuels made from renewable electricity are eligible to count toward the transport target in the RED II. The RED II presents three options for calculating the amount of renewable energy used in electrofuels in Article 25, paragraph 3:

1. Assume the average share of renewable electricity in the country of production when importing electricity from the grid.

2. Assume 100% renewable share if electrofuels are produced via a direct connection to a new renewable electricity installation that does not import electricity from the grid.

3. Assume 100% renewable share when importing electricity from the grid if it can be demonstrated that the electricity is from renewable sources.

In Christensen and Petrenko (2017), we demonstrated that the first option would not likely be economically viable because policy support would only be given to a fraction of electrofuels produced. The second option—direct connection to a renewable electricity installation—is represented by Scenario 1 in the present study. The third option—importing demonstrated renewable electricity from the grid—is represented by our Scenario 2, where GoOs are used to certify that the electricity used is renewable. This option also presumably could include a scenario where an electrofuels facility only imported and used electricity during times when excess renewable electricity would otherwise be curtailed. However, in Christensen and Petrenko (2017), we found that such an arrangement would not be economically viable because the electrofuel facility would have to operate with a very low capacity factor.

All renewable energy that is counted toward the RED II transport target also counts toward the 32% renewable energy target; the transport target is thus nested within the overall renewable energy target. Transport fuels are counted toward the overall renewable energy target on the basis of the energy content in the combusted fuel: "*final consumption of energy from renewable sources in transport*" (European Union, 2018: Article 7, paragraph 1c). For example, the energy content of wheat ethanol, not the energy content of the wheat feedstock, which is larger, counts toward both the transport target and the overall renewable energy target.

Importantly, this may not be true for electrofuels: "Renewable liquid and gaseous transport fuels of non-biological origin that are produced from renewable electricity shall only be considered to be part of the calculation pursuant to paragraph 1(a) when calculating the quantity of electricity produced in a Member State from renewable energy sources" (RED II, Article 7, paragraph 4a). Paragraph 1(a) is the "gross final consumption of electricity from renewable energy sources." Electrofuels count toward the transport target on the basis of final energy in the fuel, but it appears that Member States may count these fuels toward the overall renewable energy target on the basis of the renewable electricity input. The language is not entirely clear and it is possible to interpret it to mean that the amount of energy in the finished fuel should count toward the overall renewable energy target. If the amount of input electricity is counted, this is similar to counting the energy in raw wheat instead of ethanol toward the overall renewable energy target. Because electrofuels have at best an overall efficiency of around 50%, the amount of energy in the input electricity is around double that in the finished fuel. Figure 6 demonstrates this problem in a schematic. For the same amount of energy delivered as transport fuel, the RED II would count a contribution from electrofuels as double the amount of energy as an equivalent contribution from biofuels toward the overall renewable energy target, as shown on the left side of the figure. The right side of the figure shows the actual amount of renewable energy delivered. Because double the amount of energy delivered in the final electrofuel is counted toward the overall renewable energy target, a lower amount of renewable energy is needed outside the transport sector to meet the target. This results in overall lower renewable energy usage when electrofuels are used in the RED II compared to biofuels.

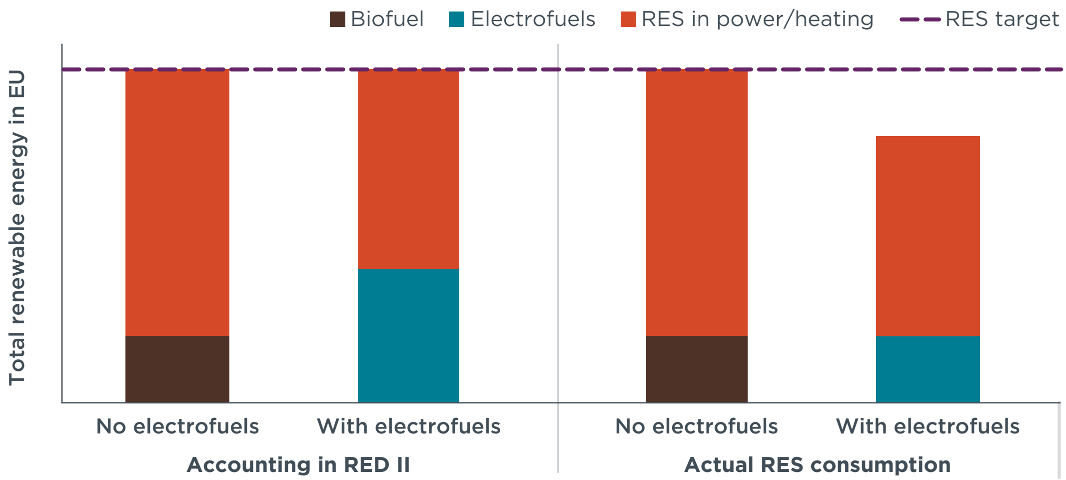

Figure 6. Schematic demonstrating how the renewable energy content in electrofuels as accounted for in the RED II would differ from the amount of energy delivered as fuel.

Advanced biofuels also have a form of double counting in the RED II, but the net effect is different than with electrofuels. Member States may count advanced biofuels at twice their energy content toward the transport energy target, but not the overall renewable energy target. Using more advanced biofuels may thus reduce the total amount of renewable energy used in transport fuel, but does not reduce the total amount of renewable energy used in the EU.

This accounting problem with electrofuels only matters if the 32% renewable energy target is just met and not exceeded. Figure 6 illustrates a situation in which the renewable energy target is just met. This outcome would be avoided if the EU were to significantly exceed the regulatory target for use of renewable energy (i.e., if renewable energy deployment starts to be driven by the market faster than by the regulation, or is driven by national policy that goes beyond the RED II target), in which case presumably the effective double counting of electrofuels to the overall renewable energy target would not be relevant to decisions about installing new capacity.

However, we would still expect electrofuel facilities that import renewable electricity from the grid to impact the renewable share of electricity even if the renewable energy target is exceeded. This case is described by the example provided at the beginning of this section, where electricity from an existing solar installation is diverted from a nearby town to power electrofuels, and is replaced by new fossil gas electricity in that town. In reality, any additional electricity demand in the EU will be replaced by a mix of sources depending on what is most economical in different regions; some of this new electricity will likely be renewable or nuclear (with no net impact on GHG emissions) but some is likely to be fossil, increasing GHG emissions.

SCENARIOS FOR GHG ASSESSMENT

We create a set of scenarios to describe the net GHG impacts from all the possibilities discussed above. In the assessment of potential electrofuel volumes, we included two scenarios: Scenario 1 represented direct connection to a new renewable electricity installation, and Scenario 2 represented purchasing renewable electricity through a grid connection using GoOs. We subdivide those two scenarios for our GHG assessment to explore how total renewable energy usage—and thus total GHG emission reductions—would change with electrofuels depending on whether the renewable energy target is exceeded. We include a fifth scenario in which Member States count the energy in the finished fuel rather than the input electricity toward the renewable energy target. These scenario subdivisions do not affect the results on economic viability of electrofuels presented above.

Scenario 1A: direct connection to renewable electricity installation, renewable energy target just met

Scenario 1B: direct connection to renewable electricity installation, renewable energy target exceeded

Scenario 2A: importing renewable electricity from grid (using GoOs to demonstrate 100% renewable input), renewable energy target just met

Scenario 2B: importing renewable electricity from grid (using GoOs to demonstrate 100% renewable input), renewable energy target exceeded

Scenario 2C: importing renewable electricity from grid (using GoOs to demonstrate 100% renewable input), renewable energy target just met, energy content in finished fuel counted toward renewable energy target

In the remainder of this section, we present a life-cycle GHG assessment of electrofuels in each of these five scenarios.

METHODOLOGY FOR LIFE-CYCLE GREENHOUSE GAS ASSESSMENT

We include both direct emissions (from fuel production and transport) and indirect emissions (from impacts to electricity production for non-transport sectors). We assume 1 gCO_2e/MJ for direct emissions following Geitmann (2000) and Edwards, Larive, Rickeard and Windorf (2014). The direct emissions are low because the CO_2 emitted from fuel combustion is offset by CO_2 sequestration in fuel production. We also include construction emissions of renewable electricity installations. This is not always included as a term in life-cycle analysis. In fact, construction emissions from fuel production facilities are almost never included because these emissions are much lower than from other sources over the lifetime of fuel production (we do not include fuel production facility emissions here). However, construction emissions from solar and wind installations are larger than those for fuel production facilities: around 3 gCO_2e/MJ for wind power and around 9 gCO_2e/MJ for solar power (Edenhofer and Madruga, 2012).

For scenarios 1A and 2A, we include indirect emissions from increased nonrenewable energy use due to the reduction in renewable energy needed outside the transport sector to meet the RED II target if the target is just met. For this part of the analysis, we assume an overall conversion efficiency of 53%, which is in the middle of the range of futuristic conversion efficiencies of the pathways in our volumes assessment. For 100 MJ of renewable electricity used to make electrofuels, 53 MJ is delivered as renewable energy in the final fuel. The remaining 47 MJ is lost upon conversion. If electrofuels counted toward the renewable energy target on the basis of the finished fuel, the lost 47 MJ would need to be supplied in the form of a new additional renewable energy installation. If electrofuels are counted on the basis of the renewable energy input, that amount of additional renewable energy would not be supplied, but additional electricity must still be produced to meet demands outside fuel production. If the renewable energy target is just met, this will be nonrenewable, including both fossil fuels and nuclear. Thus, for every 100 MJ of electrofuels produced, we account for indirect emissions from 47 MJ of additional fossil fuel and nuclear power. We assume the mix of coal, gas, petroleum, and nuclear mirrors the relative share of new capacity of each of these types of generators built in the year 2030 using data in BNEF's projection for Germany, Italy, France, UK, and "Other Europe." We estimated new capacity built following our methodology in Christensen and Petrenko (2017). For these scenarios, we count wind and solar installation construction emissions only for the net increase in generation of these renewables (i.e., 53% of the total amount of electricity used in electrofuel production).

For Scenario 2B, the RED II renewable energy target has no effect at all. Indirect emissions occur from displacing renewable electricity that otherwise would have been used for non-fuel purposes and necessitating increased electricity generation to meet the overall greater demand. In this scenario, we assume that the new electricity installations that would be built reflect the relative share of new capacity of each type of electricity generation in BNEF's projection, as above, but including renewable energy as well as fossil fuels and nuclear. Using this approach, we estimate that approximately 52% of new capacity built in 2030 will be renewable. As for scenarios 1A and 2A, we count wind and solar installation construction emissions only for the net increase in generation of these renewables (i.e., 52% of the total amount of electricity used in electrofuel production). Emission factors for each type of electricity production are listed in Christensen and Petrenko (2017).

For scenarios 2A, 2B, and 2C, we account for another type of indirect emissions. As discussed above in estimating grid balancing costs, variable renewable electricity sources are associated with greater generation forecast errors than baseload power sources. Utilities may increase the use of short-term spinning reserves to be able to meet power demands when variable renewable energy sources generate less electricity than forecast. These spinning reserves generally use natural gas, and keeping them online and ready to ramp up generates a low level of emissions, detracting from the climate savings of using renewable energy sources instead of fossil baseload power. An increase in the amount of grid-connected renewable energy sources driven by an increase in grid-connected electrofuel production would thus be expected to increase use of natural gas spinning reserves. The amount of spinning reserve capacity necessary to keep online to balance renewable electricity variability may be reduced on a grid-scale if many variable renewable energy sources are connected to the grid in different geographic locations because generation variations from forecasts at one variable renewable electricity installation tend to offset those at another to some degree (for example, a shortfall in wind power in northern France may be offset by excess wind power generation in southern France). Fripp (2011) assessed the emissions from natural gas spinning reserves to cancel out only 6% of the emissions savings from replacing fossil baseload power with variable RES when this kind of distributed generation is taken into account and occurs over a large area (500 km radius). This area may be larger than the functional grid area in many locations in the EU at present, given current barriers to cross-Member State electricity interconnections and even sub-national transmission limitations in Germany, for example (Appunn, 2018). But with expected improvements in transmission and interconnections (European Commission, n.d.), it is conceivable that 500 km may be a typical transmission radius in 2030. We thus adopt the estimate of 6% fossil emissions rebound for GHG savings from wind and solar power compared to natural gas. The low magnitude of this term may not be intuitive. In a simplified example, an electrofuel facility purchasing GoOs from a nearby solar facility will operate 24 hours a day, only around eight of those occurring at the same time the solar facility is producing electricity. But because the number of GoOs must match the total amount of renewable electricity claimed at the electrofuel facility, this means that during those eight hours, the solar installation must produce around three times as much electricity as the electrofuel producer uses, and the excess is used by other consumers elsewhere. On net, the same amount of renewable electricity is produced as the amount of electricity used by the electrofuel facility. The 6% represents emissions only from the increased usage of spinning reserves, not from any shortfall in overall renewable electricity supply.

For Scenario 1B, there are no indirect effects on renewable energy usage outside fuel production.

RESULTS ON GREENHOUSE GAS IMPACTS

Greenhouse gas intensity of electrofuels

Figure 7 presents the direct and indirect emissions and the total life-cycle GHG performance for each scenario in our analysis. Indirect emissions from increased nonrenewable electricity production is by far the largest contributor to overall emissions in this analysis. In Scenarios 1A and 2A, these indirect emissions are so high that the resulting electrofuel offers only very small GHG benefits compared to fossil fuels. In Scenario 2B, we find that electrofuels are slightly more GHG intensive than the fossil fuel comparator.

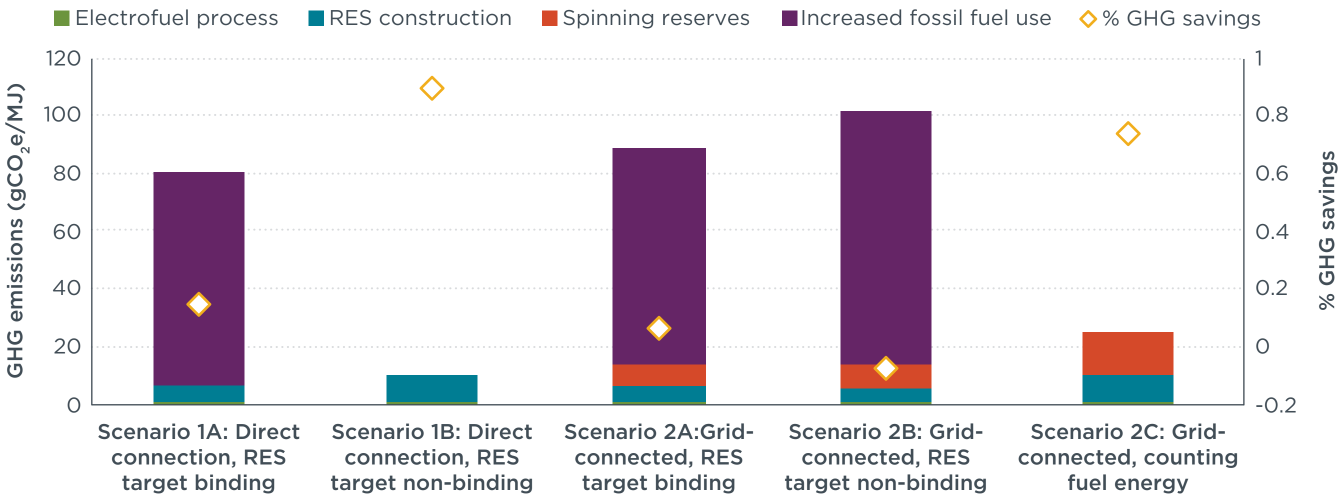

Figure 7. Direct and indirect emissions from electrofuel production in the EU in 2030 in various scenarios and % GHG savings compared the fossil fuel comparator of 94 gCO_2e/MJ

Only in Scenarios 1B and 2C do electrofuels offer high GHG savings compared to fossil transport fuels. These scenarios do not cause an indirect increase in nonrenewable electricity generation. Importantly, even when electrofuel producers have a direct connection to a new renewable electricity generator, there can be high indirect emissions from reduced renewable energy consumption elsewhere if the amount of energy input to the electrofuels process is counted toward the RED II renewable energy target and if this target is just met (Scenario 2A). At present it is not possible to know whether the renewable energy target will be exceeded. Therefore, these results indicate that the only way in which high GHG savings from electrofuels can be guaranteed is Scenario 2C: counting only the energy in the final fuel, not the input energy, toward the overall renewable energy target. Below, we discuss potential policy options for achieving this scenario.

Overall GHG reduction potential

The overall potential for GHG reductions from electrofuels depends on both the GHG intensity per MJ fuel and the total potential volumes that could be economically produced. Figure 8 presents the maximum potential GHG reduction from the five scenarios at varying levels of policy support. Above, we found that Scenario 1B achieves the highest GHG reductions per MJ, closely followed by Scenario 2C. However, the total potential GHG reductions from electrofuels in Scenario 2C are much higher than for any other scenario. This is because the economics of grid-connected electrofuel production are more favorable than those of electrofuels produced by direct connection to renewable electricity installations. We project that very little GHG savings could be achieved in Scenarios 1A and 2A because the GHG intensity of these pathways is similar to the fossil fuel comparator. In Scenario 2B, because the GHG intensity of electrofuels is slightly higher than fossil fuels, the total climate impact worsens the more electrofuels are produced in this scenario. In all scenarios, the total GHG impact is highly dependent on the level of policy support because this strongly affects the volumes of electrofuels that can be produced. Figure 8 also shows the share of total 2030 road transport emissions that could be avoided by electrofuels in each scenario. Even with very high policy support of 3 euros per liter, we project that the most favorable scenario could deliver only around 4 million tonnes CO_2e reduction per year by 2030, equivalent to 0.5% of projected total road transport emissions in the EU reference scenario (European Commission, 2016b). Our analysis strongly suggests that, within the 2030 time frame, electrofuels can deliver only a very small fraction of targeted GHG reductions in the transport sector. Importantly, if Member States count the input energy to electrofuels production toward the RED II renewable energy target, it is likely that virtually no net climate benefit will be achieved.

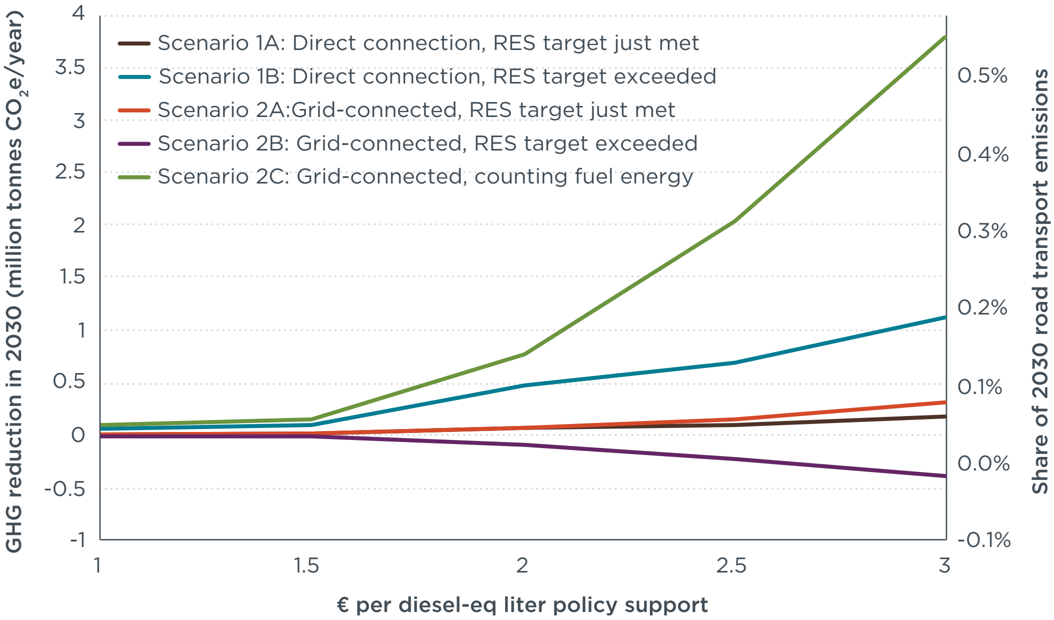

Figure 8. Maximum 2030 GHG reduction potential from electrofuels in the EU by scenario and level of policy support, assuming CO_2 from point sources.

It is important to note that our interpretation of policy support levels may be different in Scenario 2C than the other scenarios. Earlier, we explained that the levels of policy support analyzed here could represent a combination of incentives, for example a renewable electricity feed-in tariff along with a renewable fuel subsidy. However, if electrofuels are counted on the basis of fuel energy rather than electricity input, presumably only the fuel production would receive incentives as part of RED II implementation. As a simple example, a Member State might offer a feed-in tariff to wind and solar generators to incentivize enough renewable electricity generation to meet the 32% renewable energy target. But if the electricity used in electrofuel production is not itself eligible to count toward that 32% target, it would not make sense for the Member State to provide that electricity generator the feed-in tariff. Instead, it would be logical for the Member State to provide support only to the electrofuel producer, since that producer is delivering the energy that will be counted toward the RED II. To reach the highest level of electrofuel potential in this analysis, the Member State would have to deliver the entire 3 euros per liter to the electrofuel producer. This will be particularly impactful for Member States that offer the same incentives for all types of non-food based alternative fuels. It will be harder for electrofuels to compete economically with advanced biofuels if the input renewable electricity is not eligible for electricity feed-in tariffs (Scenario 2C) compared to a scenario where it is.

Cost of emission reductions from electrofuels

Even in the best-case scenario (Scenario 2C), electrofuels are an expensive GHG mitigation strategy. Three euros per liter translates to 1,213 euros per tonne CO2e abated, given the GHG intensity of electrofuels in Scenario 2C (Figure 7). This is much higher than the cost of GHG reduction generally expected of alternative fuels. For example, California has a cap of $200 per tonne CO_2e on credit prices for its Low Carbon Fuel Standard (Wade, 2016).

We also estimate the cost of using electrofuels as a strategy for reducing the overall emissions of passenger vehicles. If electrofuels were eligible to count toward the EU's passenger vehicle CO_2 standards, this strategy would cost 306 euros for each gram CO_2e reduced per kilometer. This calculation assumes the following: vehicle efficiency of 0.0363 L/km (what would typically be needed to meet the 95 gCO_2e/km standard for 2021 [Regulation (EU) No 333/2014]); 15 year vehicle lifetime; 117,000 km annual distance driven by each car (Odyssee-Mure, n.d.). The cost of using enough electrofuels over the lifetime of an average car to achieve one gram CO_2e reduction per kilometer over that entire lifetime is 694 euros.

POLICY RECOMMENDATIONS

This research points to several policy actions the European Commission and Member States could take to ensure that renewable electrofuels deliver high GHG savings and would maximize the total potential climate benefit of this type of fuel. In particular, we put forward several ideas to ensure that the effective double counting of energy in electrofuels toward the RED II renewable energy target does not occur.

Member States might be able to interpret the counting provision in the RED II to mean that for renewable fuels of non-biological origin, the energy content in the transport fuel should count toward the overall renewable energy target. The RED II language is not clear on this point. Alternatively, Member States could simply take measures to increase the amount of renewable energy consumed above the 32% RED II target by approximately the same amount of energy in electrofuels counted toward the RED II.

Another solution would be to include indirect emissions accounting in assessing the life-cycle GHG performance of electrofuels. According to the RED II, the European Commission is tasked with setting a GHG calculation methodology for renewable fuels of non-biological origin. If the Commission included indirect emissions accounting for these fuels, it would likely find that electrofuels would only qualify for the 70% GHG reduction threshold required for renewable fuels of non-biological origin if specific and robust measures were taken to ensure full additionality of renewable electricity used for electrofuel production. For example,Timpe, Seebach, Bracker, and Kasten (2017) introduced the concept of "GOplus" certificates representing renewable electricity that is not counted toward the RED II renewable energy target. Requiring GOplus certificates for electrofuel producers would reduce or eliminate the likelihood of indirectly lowering renewable energy use outside fuel production. To be fully effective, GOplus certificates would be needed even for off-grid electrofuel producers.

Member States may be able to similarly exclude electrofuels without GOplus certificates from RED II accounting and support on the basis of life-cycle GHG performance, as long as they applied similar indirect emissions accounting to other renewable fuels of non-biological origin.

The Commission or Member States could determine that electrofuels in general do not meet the 70% GHG reduction threshold and thus exclude this category of fuels entirely from counting toward the RED II. However, this option could stymie investment in a technology that has the potential for delivering long-term GHG reductions if using 100% additional renewable electricity.

Lastly, we strongly recommend that electrofuels not be allowed to count toward multiple policy targets, for example counting the same liter of electrofuel in both the RED II and vehicle CO_2 standards. Allowing electrofuels, or any other type of alternative fuel, that is already incentivized by the RED II to count toward vehicle standards would reduce the use of other decarbonization measures, such as electrification and efficiency improvements, without delivering any additional climate benefit. This would effectively reduce the stringency of the EU vehicle CO_2 standards.

CONCLUSIONS

Electrofuels can be part of the solution for long-term decarbonization of the transport sector, but these alternative fuels are unlikely to deliver much of the EU's climate goals in the 2030 time frame. Our analysis finds that, even with very high policy support of 3 euros per diesel-equivalent liter, electrofuels are unlikely to displace more than 0.4% of petroleum used in road transport fuel by 2030. At lower—and perhaps more realistic—levels of policy support, potential volumes of electrofuels are greatly reduced. Electrofuels should be seen as a potential long-term option for transport decarbonization, but the EU should recognize that other measures are necessary to achieve significant GHG reductions in the 2030 time frame.

The climate impact of electrofuels is heavily dependent on their treatment by policy. Electrofuels only deliver climate benefits if produced from low-carbon renewable electricity such as wind and solar power. Even when produced solely from renewable electricity, electrofuel production can indirectly impact renewable energy usage elsewhere because of the energy accounting methodology in the RED II. If electrofuels count toward the 32% renewable energy target in the RED II on the basis of the renewable electricity input rather than the energy content of the fuel, their production will reduce the total amount of renewable energy consumption necessary to meet the 32% target. We find that in most cases with this interpretation of the RED II, electrofuels will not significantly reduce GHG emissions compared to petroleum.

We recommend that EU policymakers explore options to correct the over-counting of electrofuels toward the 32% renewable energy target. One promising option is to require electrofuel producers to submit GOplus certificates to demonstrate that the renewable electricity used, whether through a grid connection or a direct connection, has not been counted toward the 32% renewable energy target by Member States. Another key recommendation is to not allow electrofuels to count toward vehicle CO_2 standards in the EU. Counting the same fuel toward both policies would effectively reduce the stringency of the vehicle standards without delivering additional climate benefits. If measures are taken to ensure that GHG reductions from electrofuels are additional, these fuels can make a meaningful—if modest—contribution toward the EU's renewable energy and decarbonization goals.

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APPENDIX

ELECTROFUEL POTENTIAL RESULTS FOR 2040 AND 2050

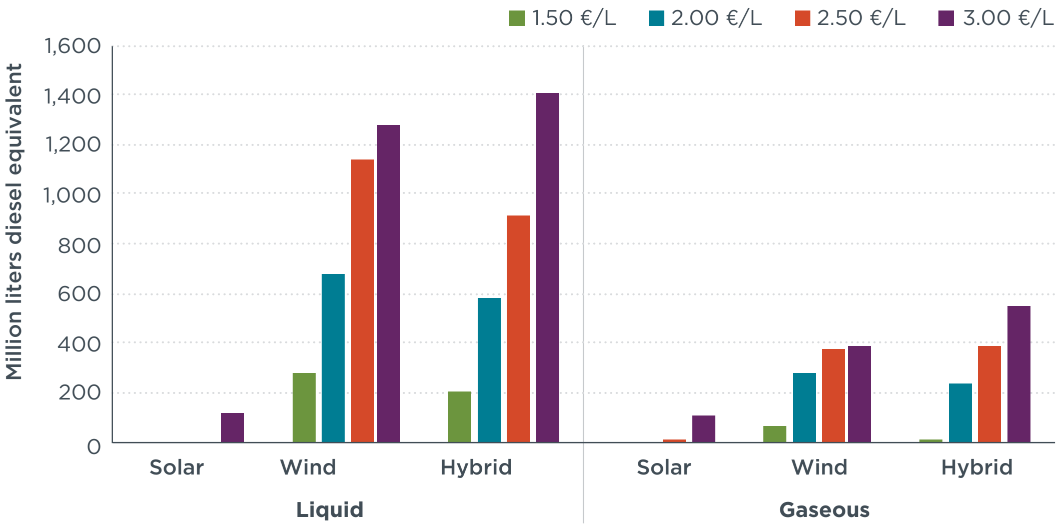

Figure A1: Total EU electrofuel potential in 2040 in Scenario 1 (direct connection) with point source CO_2 (million liters diesel equivalent).

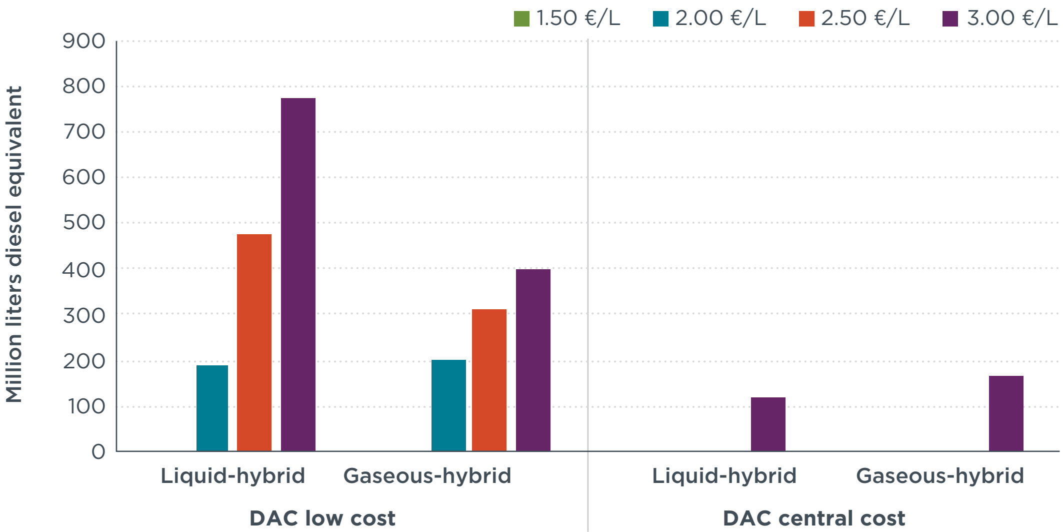

Figure A-2: Total EU electrofuel potential in 2040 in Scenario 1 (direct connection) with DAC CO_2 and a hybrid renewable electricity (million liters diesel equivalent).

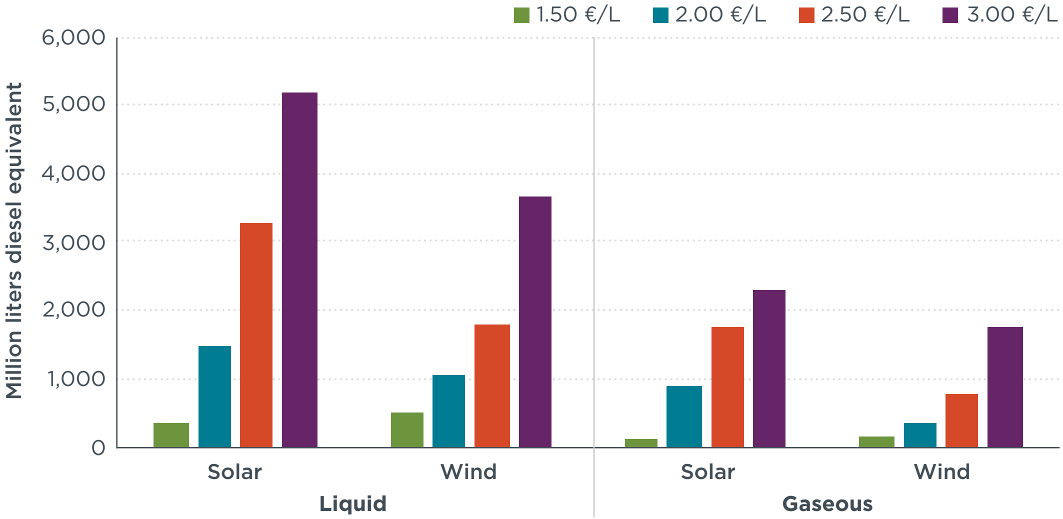

Figure A-3: Total EU electrofuel potential in 2040 in Scenario 2 (grid-connected) with point source CO_2 (million liters diesel equivalent).

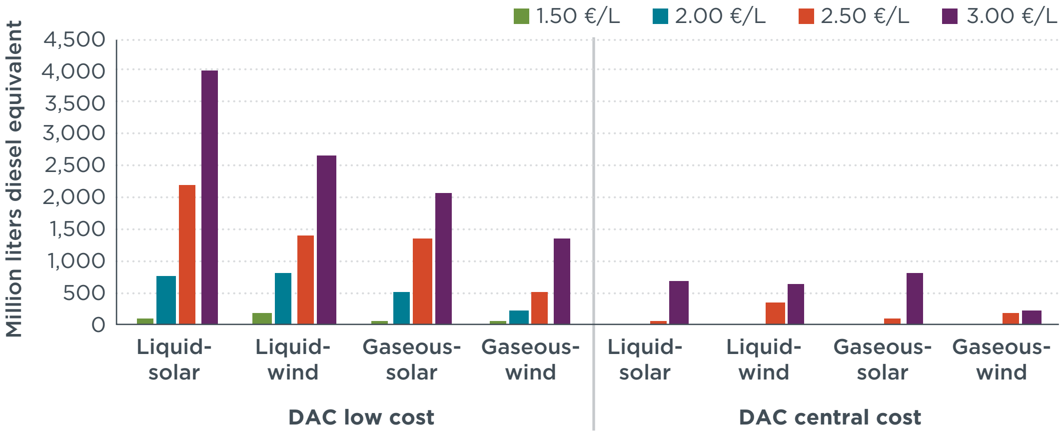

Figure A-4: Total EU electrofuel potential in 2040 in Scenario 2 (grid-connected) with DAC CO_2 (million liters diesel equivalent).

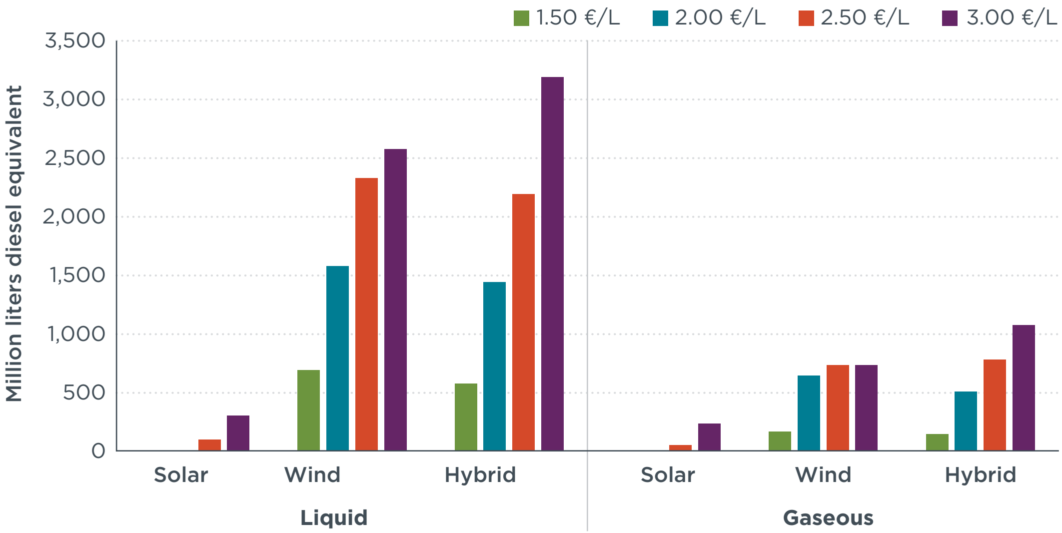

Figure A-5: Total EU electrofuel potential in 2050 in Scenario 1 (direct connection) with point source CO_2 (million liters diesel equivalent).

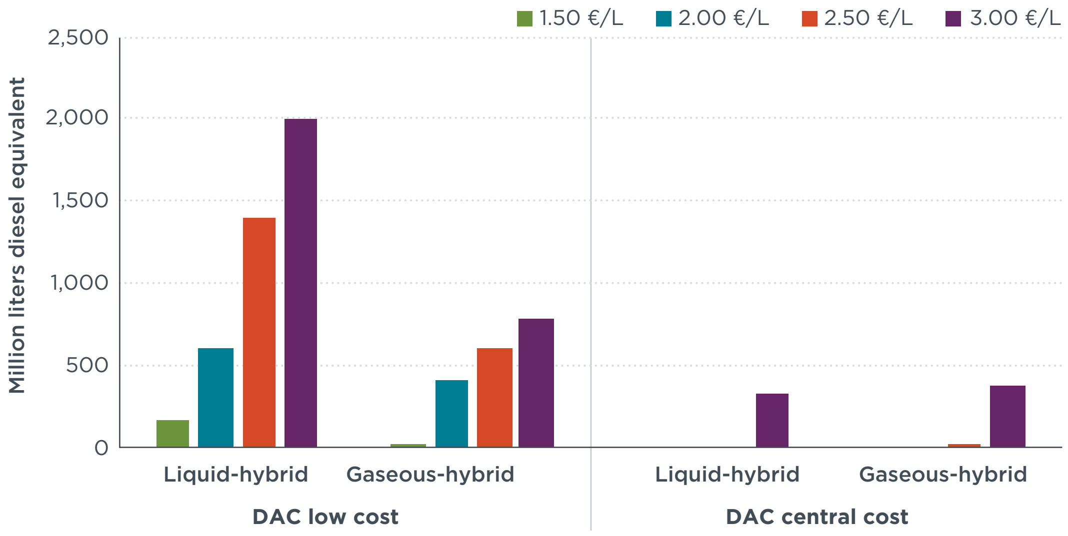

Figure A-6: Total EU electrofuel potential in 2050 in Scenario 1 (direct connection) with DAC CO_2 and a hybrid renewable electricity (million liters diesel equivalent)

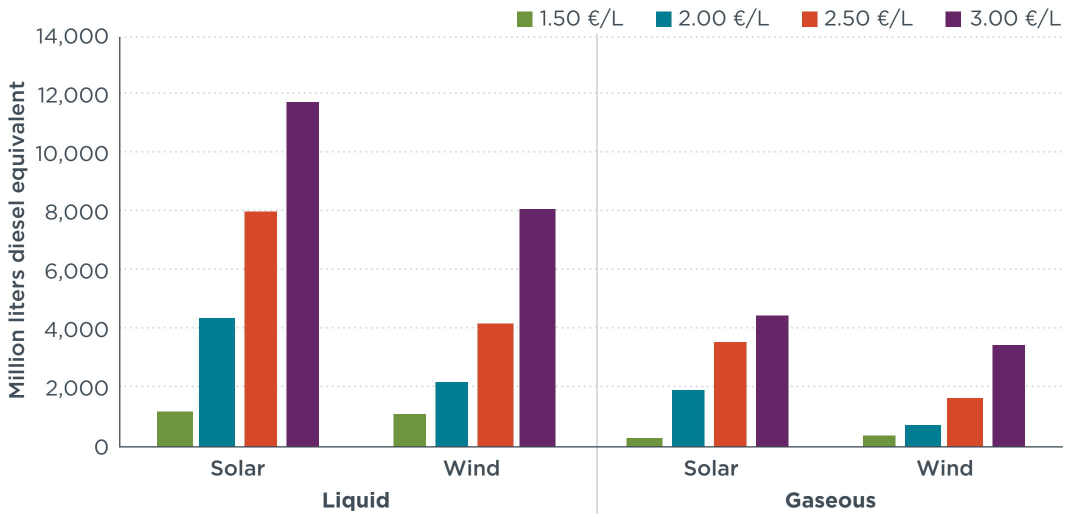

Figure A-7: Total EU electrofuel potential in 2050 in Scenario 2 (grid-connected) with point source CO_2 (million liters diesel equivalent)

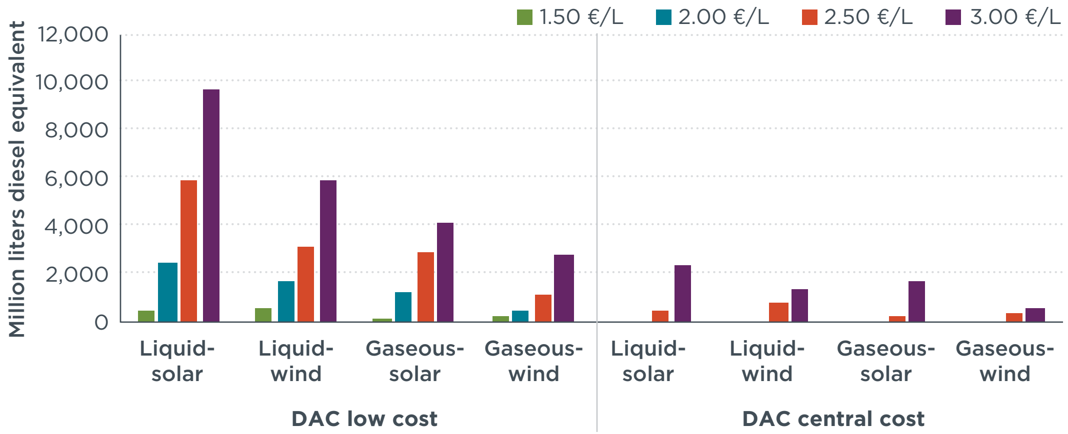

Figure A-8: Total EU electrofuel potential in 2050 in Scenario 2 (grid-connected) with DAC CO_2 (million liters diesel equivalent)

RENEWABLE ELECTRICITY PRICES

Table A. Electricity price projections, broken out by generation costs, grid fees, and taxes for each EU Member State for 2030, 2040, and 2050, in constant 2018 euros per MWh

Country	Taxes (constant over time)	Generation – solar			Generation – wind			Grid fees		
		2030	2040	2050	2030	2040	2050	2030	2040	2050
Austria	20.5	57.7	52.6	48.0	91.8	90.0	88.6	19.1	19.5	20.2
Belgium	22.1	75.2	68.8	62.8	205.4	201.7	198.9	24.5	24.9	25.6
Bulgaria	11.9	47.5	43.4	39.7	144.5	141.7	139.8	5.9	6.3	7.0
Cyprus	7.7	62.8	57.7	52.6	137.5	134.8	132.9	23.0	23.3	23.9
Czech	16.0	71.1	65.1	59.1	184.6	180.9	178.6	16.4	16.6	16.9
Denmark	25.2	82.6	75.2	68.8	87.2	85.4	84.5	28.4	29.9	31.8
Estonia	11.3	126.5	115.4	105.2	111.2	108.9	107.5	29.5	29.8	30.6
Finland	6.1	195.2	177.7	162.0	96.9	95.1	93.7	15.6	15.7	15.9
France	17.8	57.2	52.2	47.5	116.8	114.5	113.1	18.1	18.4	18.8
Germany	51.8	85.8	78.0	71.1	109.8	107.5	106.2	25.1	26.0	27.6
Greece	11.1	41.1	37.8	34.6	120.0	117.7	115.8	10.4	11.1	12.2
Hungary	13.5	48.5	44.3	40.6	109.8	107.5	106.2	21.2	21.3	21.4
Ireland	7.5	97.4	88.6	80.8	137.5	134.8	132.9	24.0	24.8	26.8
Italy	50.0	51.2	46.6	42.5	80.8	79.4	78.5	17.2	17.8	18.6
Latvia	22.1	122.8	112.2	102.0	157.4	154.2	152.3	34.0	34.0	34.2
Lithuania	8.9	131.5	120.0	108.9	151.4	148.6	146.3	31.5	31.8	32.5
Luxembourg	4.1	84.9	77.5	70.6	109.4	107.5	106.2	12.7	12.9	13.1
Malta	0.0	68.3	62.3	56.8	177.7	174.5	172.2	22.3	22.6	22.8
Netherlands	12.3	262.6	238.6	216.9	95.1	93.2	92.3	18.3	18.6	19.3
Poland	4.5	86.8	78.9	72.0	96.5	94.6	93.2	22.8	23.0	23.7
Portugal	19.3	31.4	28.6	26.3	102.0	100.2	98.8	25.0	25.9	28.0
Romania	9.4	48.0	43.8	40.2	124.6	122.3	120.9	29.6	30.3	31.8
Slovakia	27.6	57.7	52.6	48.0	151.8	149.1	147.2	36.8	36.9	37.1
Slovenia	8.3	76.2	69.7	63.2	89.1	87.7	86.3	15.1	15.2	15.3
Spain	23.9	38.8	35.5	32.3	98.8	96.9	96.0	16.4	17.2	19.1
Sweden	0.6	140.8	128.3	116.8	36.0	35.1	34.6	19.4	19.8	20.8
UK	24.4	87.7	79.8	72.9	133.4	131.1	129.2	33.4	33.9	35.1