Cerulogy

What role is there for electrofuel technologies in European transport's low carbon future?

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Executive summary

Renewable electrofuels in the EU energy mix

As the European Union reduces the greenhouse gas intensity of its economy between now and 2050, decarbonising the transport sector will continue to present particular challenges. For passenger transport electrification, coupled with the decarbonisation of the grid electricity supply, seems to provide the main answer, but it is widely accepted that aviation will continue to rely on liquid fuels for the foreseeable future, and heavy duty road vehicles and shipping are also unlikely to be decarbonised solely through electrification (although electrification options exist in many cases). Efficiency improvements can do a great deal to reduce energy consumption, but not to eliminate it entirely. Biofuels have long been held up as a potential solution to fill these gaps that other solutions may be unable to reach, but the use of land for bioenergy cropping remains controversial on sustainability grounds, and the volumes of advanced biofuel supply that are sustainably achievable are likely to fall significantly short of the residual liquid fuel demand in the transport sector.

In this context, there is renewed interest at the moment in 'renewable fuels of non-biological origin', including 'renewable electrofuels'. The fundamental technological building blocks of electrofuel production are electrolysis, in which water is broken down into hydrogen and oxygen with the use of electrical energy, and chemical fuel synthesis in which hydrogen is reacted with the carbon from carbon dioxide to produce more complex hydrocarbons. Using methanation technology, methane can be produced, substitutable with natural gas. Other technologies, often referred to as 'power-to-liquids', allow the synthesis of liquid electrofuels such as methanol, di-methyl ether and drop-in synthetic diesel, petrol and jet fuels (produced either via methanol production, or directly from hydrogen and carbon monoxide through the Fischer-Tropsch process). Many of the technological steps required for liquid electrofuel production are already widely used in other industrial applications, but some parts of the chain have lower technology-readiness levels, and the full process from electricity to synthetic fuel has never been demonstrated at commercial scale (although pilot scale facilities exist).

Drop-in electrofuel production is not as energy efficient as direct supply of electricity for electric drive vehicles. For instance, Transport and Environment (2017) state that the direct supply of electricity for battery charging delivers an overall 73% efficiency from electricity production to energy use in transport, while use of hydrogen in a fuel cell vehicle delivers only 22% energy efficiency and drop-in electrofuels deliver only 13% overall efficiency. Still, electrification cannot meet all transport energy requirements, and even in passenger vehicles it is likely to take decades to eliminate internal combustion engine vehicles from the fleet. In this report, we have focused on the electrofuel pathways that can produce true 'drop-in' alternative fuels that could be used in existing engine types and existing infrastructure, and that are therefore best suited to meet the 'residual' demand for liquid fuels that will be left even after efficiency improvements and electrification.

Compared to biofuels, electrofuels from zero-carbon renewable energy (such as wind and solar power) have a much lower associated sustainability risk. The land footprint of renewable electricity production is an order of magnitude below the land requirement of biofuel production, water demand for renewable electricity is far lower than for agriculture, and there are no obvious major risks of air, water and soil pollution associated with the technology (where conventional agricultural has well documented problems associated with nitrogen pollution, for instance). Provided zero-carbon renewable electricity is used for both electrolysis and process electricity, renewable electrofuels have a very small carbon footprint, of 5 gCO_2e/MJ or less. At the same time though, even an electricity supply with a low carbon intensity of 25 gCO_2e/MJ would result in electrofuels with a disappointing carbon performance (20-47% carbon savings depending on conversion efficiency). Delivering low greenhouse gas emissions requires the use of zero or near-zero carbon electricity sources. Drop-in electrofuels produced with current grid average EU electricity would have a greenhouse gas intensity approximately three times higher than liquid fossil fuels.

Achieving a low greenhouse gas emissions footprint across the system as a whole is therefore entirely dependent on the application of an appropriate and effective regulatory regime to ensure that any growth in electrofuel production must be accompanied by the development of additional zero-carbon renewable power generating capacity. The regulatory framework in the proposal for a new Renewable Energy Directive for the period 2021-2030 would be inadequate to ensure the deployment of additional renewable power generation capacity, and therefore is not fit to guarantee that expansion of electrofuels production actually reduces the overall greenhouse gas intensity of EU transport, and therefore should be amended as described below.

Electrofuel expansion would not be devoid of other sustainability risks – for instance, solar electricity generation has obvious advantages in very dry environments with high solar insolation, in which even the relatively low water withdrawals required for electrofuel production might still be locally problematic – but these ought to be manageable using the oversight systems necessary to manage the environmental impact of any large industrial project.

Potential cost of renewable electrofuel production

While the low environmental risk of electrofuel production is a significant advantage, the cost of production is likely to be a significant barrier to development in the near term. Estimates of the cost of synthetic electrodiesel production using current technologies and electricity prices are far higher than the price of fossil alternatives. Production costs in the near term are likely to be 3,000 €/toe[1] of electrodiesel (or electrojet or electropetrol), and perhaps much higher. This is at least six times more than current wholesale road diesel and jet fuel prices of around 500 €/tonne, and significantly above the production costs targeted for advanced biofuel plants. While there are some lower near-term cost estimates in the literature, these are generally predicated on either unrealistically generous electricity prices, unrealistically low cost of capital, or often both.

Figure 1 provides an indicative breakdown of the near-term costs of electrofuel production, taken from Brynolf, Taljegard, Grahn, & Hansson (2017). The pathways presented are electromethane as a natural gas substitute, Fischer-Tropsch (FT) synthesis for distillate fuels (diesel and jet) and a pathway through methanol to petrol. These cost estimates are based on an electricity price of 5 €cent/kWh and interest rate of 5%, both likely too low for near-term developments, so these numbers might be considered a lower bound on achievable prices. The cost of electricity is the dominant term in electrofuel production cost. At 5 €cent/kWh, it

1 One 'toe' is a 'tonne of oil equivalent', the amount of a given fuel containing the same energy as a tonne of oil.

contributes 1,200 €/toe of electrofuel for a facility with 50% conversion efficiency of electricity to fuel. For electricity at 10 €cent/kWh (around current EU average grid electricity prices to large industrial consumers), this doubles to 2,400 €/toe. Without low-cost renewable electricity supply, electrofuels simply cannot expect to compete with other fuel alternatives.

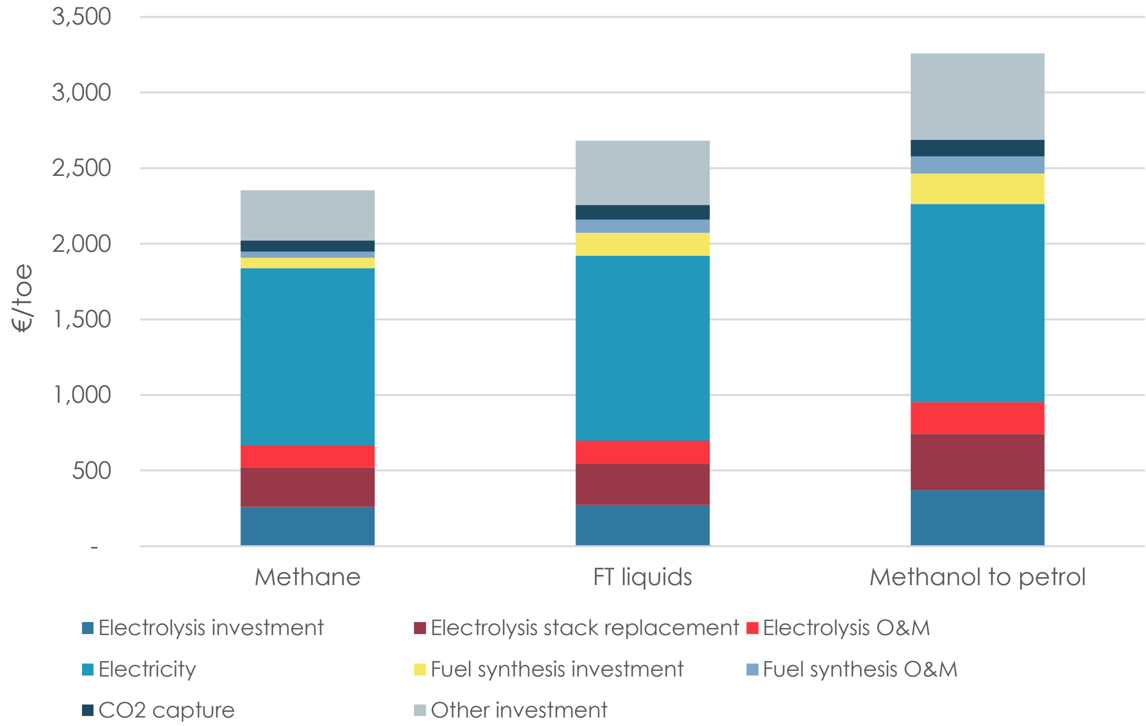

Figure 1. Near term cost of electrofuel production (Brynolf et al., 2017)

Investment, and stack replacement for low temperature electrolysers, represent the bulk of the rest of the cost. Facility operational costs and the cost of carbon dioxide as a chemical input are relatively moderate. Figure 1 assumes CO_2 supply from an industrial point source, costed at 30 Euro per tonne of CO_2 captured. Atmospheric capture of CO_2 would be more costly (expected to be about five times more costly once the technology is commercialised, but with considerable uncertainty) but would even so be unlikely to be a dominant term in the cost equation.

As with any new industrial process, there is great opportunity to reduce investment costs in particular over time, both by applying the experience of operating first of a kind facilities to reduce overnight capital costs, and by reducing the cost of capital assuming that the technology can be successfully demonstrated. By 2050, if the electrofuels industry is supported to expand and learn through experience, there is a reasonable prospect (given access to electricity at 5 €cent/kWh or less) of reducing production costs to 2,000 €/toe or less.

The future cost of renewable electricity is the most important question in assessing future electrofuel prices. Some studies anticipate levelised costs of electricity from solar PV in southern Europe to fall as low as 2 cent/kWh by 2050, in which case electrodiesel prices of

1000 €/toe could be achievable. However, many commentators have more moderate expectations of cost reduction over time for renewable electricity generation, and current predictions for electrofuel costs should not be based on the most optimistic possible assumptions about continued reduction in renewable power generation costs.

While investment cost is a significant part of the picture, it is not so dominant in the cost profile as it is for advanced biofuel facilities, which rely on low-cost waste or residual feedstocks. This means that it might be cost viable for an electrofuel facility to purposefully operate for a reduced fraction of the year in order to allow it to provide grid balancing services through demand reduction during periods of low renewable energy supply due to renewable intermittency. Given access to variable price electricity tariffs, and price variability comparable to or greater than variability documented in the existing day-ahead electricity market in Germany and Austria, it is possible that an electrofuel facility could reduce its overall operational costs by activating its electrolysis plant for only a half to two thirds of the time. The actual optimal operational model will be sensitive to the level of price variability transmitted in the industrial electricity price, any additional operational costs incurred through intermittent operation, and the actual cost of investment for each plant. The trade-off from reducing operational hours at each plant, of course, would be a reduction in total electrofuel production delivered for a given level of investment.

If economically viable models for electrofuel production to contribute to grid balancing through demand management can be developed, this will boost the case for developing a growing industry within Europe itself, rather than in areas that experience greater insolation. For electrofuel production models based on maximising operational hours, operation using solar energy in areas of highest solar power potential will have a natural economic advantage.

Resource and sustainability implications of a renewable electrofuel industry

In the most ambitious studies considered for this report, scenarios are constructed in which electrofuels make a major contribution to EU transport energy demand in 2050, requiring commercial deployment by 2030 followed by rapid expansion. In these scenarios, the expansion of electrofuels production would require vast investments and a massive expansion in European renewable electricity generation. (Schmidt, Zittel, Weindorf, & Raksha, 2016) present scenarios for 100% renewable transport energy in Europe including a large contribution by liquid renewable electrofuels alongside the use of electric vehicles. Depending on the rate of electrification of passenger vehicles and assumptions on overall transport energy demand, these scenarios show renewable electricity demand from the transport sector of anything from double to quadruple expected 2050 EU renewable electricity generation for all other sectors. A more moderate target of delivering 50% of EU aviation fuel[2] from electrofuels by 2050 would still require a level of EU renewable electricity generation in 2050 equivalent to a quarter of total current EU electricity generation. Delivering 50% of truck fuel in 2050 would require additional renewable electricity generation equivalent to over a third of the current EU electricity supply. Clearly, any of these scenarios would have significant implications for EU renewable electricity investment and electricity grid management, even if the facilities in question were operating at less-than-100% capacity to support grid balancing.

2 Including both intra-EU domestic and international flights.

The investments required to deliver fuel production on this scale would also be large. Delivering 50% of EU aviation fuel would require of the order of €300 billion in cumulative investment for the electrofuel production facilities alone (although there is considerable uncertainty around the precise cost number), plus the cost of additional renewable power capacity (perhaps €450 billion in investment). Given the resource intensity and cost of expanding electrofuel production, these technologies should be considered as a long-term climate solution only for relatively small niches of demand that are not readily addressed with other approaches such as electrification. Given the size of the challenge of delivering 50% of aviation fuel, it is certainly difficult to imagine electrofuels ever delivering a significant fraction of energy for passenger cars.

The renewable electrofuel industry confronts not only technical and financial challenges, but also regulatory challenges. Renewable electrofuels have an expanded role in the regulatory framework proposed for the RED II, but this proposed framework raises some important questions. Firstly, there are issues in the way that the proposed legislation deals with the question of what it means for an electrofuel facility to run on renewable electricity. The legislation requires that a facility should have a direct connection to a renewable power facility in order to produce fuel classified as renewable. On face value this would seem to guarantee that electrofuels production is accompanied by new renewable power capacity, but there is an apparent double counting in the Directive that could undermine the environmental performance dramatically.

As we understand the Commission's proposal, the combustion of renewable electrofuels in vehicles would count towards 'final consumption' of renewable energy in transport for the purposes of the incorporation obligation for advanced fuels, but the use of renewable electricity at the electrofuel plant would also be counted towards 'final consumption' of renewable energy against the overall EU targets. The consequence of this is that installing renewable power capacity to supply an electrofuel facility would reduce the amount of renewable power generation needed elsewhere in Europe to meet the renewables targets. Even though an electrofuel facility was directly connected to a wind farm, the net result for the energy system as a whole could be a mix of additional renewable capacity and continued fossil power generation, with as little as 56% of additional electricity generation being renewable. This would eliminate the climate benefit of the electrofuel production at the EU level, while effectively gifting the power generation sector a free reduction in the ambition of the renewability targets for grid electricity.

This regulatory problem could be simply resolved by requiring that electricity generated for electrofuel production was not counted or incentivised as final consumption of renewable electricity. This could be demonstrated through a system of renewability certificates, awarded to renewable electricity generators opting out of receiving renewable electricity incentives directly. The existing system of renewable 'guarantees of origin' (GOs) would not be adequate for this purpose, as it is intended to prevent a given kWh of renewable electricity being sold to two or more different consumers, not to prevent a given kWh of electricity being double counted into two or more incentives. It would therefore be necessary to introduce a new system, which some analysts have described as 'GO-plus' (Tempe, Seebach, Bracker, & Kasten, 2017).

Under the proposed RED II legislation, electrofuel production would be over-incentivised compared to both advanced biofuels and the use of electricity directly in electric vehicles. Preventing renewable electricity producers from receiving both renewable electricity and renewable transport fuel incentives would resolve the additionality problem, and remove a potential source of over-compensation of electrofuel producers. To accompany this measure, policy makers should consider adding flexibility by removing the requirement for a direct connection to renewable electricity production, as it would be redundant given effective mechanisms to guarantee additional renewable electricity being added to the system.

A similar double counting issue presents itself in the field of carbon dioxide accounting. The proposed rules would allow electrofuels to be produced using carbon dioxide captured from industrial process. This is appropriate in the context of the very high levels of carbon dioxide emissions currently associated with industry and power generation; the atmosphere doesn't care whether carbon dioxide is delivered to an electrofuel plant straight from the chimney of an industrial plant that would otherwise emit it, or by extracting ambient carbon dioxide from the atmosphere. In the short term it is environmentally preferable to utilise high-concentration CO_2 sources where possible, than to expend energy concentrating carbon dioxide from the atmosphere. In the long term, if the electrofuels industry grows very large as CO_2 emissions are reduced, there may be a need to introduce rules to encourage atmospheric capture, but this is highly unlikely to be necessary until at least 2040.

While allowing the use of industrial CO_2 in electrofuel production is appropriate, it seems likely that some industrial operators may ask to be able to claim credit under the ETS for capturing carbon dioxide that is then supplied to electrofuel suppliers. This should not be allowed – to reward carbon capture both in the ETS through credits to industrial facilities and also through treating electrofuels produced from captured fossil carbon as carbon neutral would represent a double counting that would undermine broader climate objectives. It is therefore strongly recommended that CO_2 captured from fossil point sources should not be credited under ETS if supplied for electrofuel production. Failing to deal with this potential double counting issue would result in a serious distortion of incentives in favour of CO_2 capture for electrofuel production (and combustion) and against CO_2 capture for permanent sequestration.

Regulating for a renewable electrofuels industry

In order to guarantee a positive environmental contribution from an EU renewable electrofuels industry, the following regulatory requirements are suggested:

1. Renewable electricity used for renewable electrofuels should be additional to renewable electricity generated for compliance with existing EU targets. This could be implemented by providing certificates to renewable electricity generators for opting out of being counted and incentivised in existing renewable electricity policies, to be redeemed for compliance by electrofuel suppliers. With such a certificate system in place, direct connection to renewable power generators may not be necessary.
    a. For imported electrofuels, a comparable requirement should be imposed that renewable electricity consumed for electrofuels supplied to Europe should not be counted towards any domestic targets.
2. The provenance of CO_2 for electrofuel production should not be limited to either atmospheric capture or biogenic combustion.
    a. This rule should be reviewed in 2030, with the possibility of requiring atmospheric capture after 2040.

3. To guarantee that renewable electrofuels should have low lifecycle greenhouse gas intensity, only zero-carbon renewable power generation should be eligible for certification and use in renewable electrofuel production.

4. For any electrofuel facility using renewable solar power a basic local water availability assessment should be required. In cases where the local environment is identified as arid, a detailed water use impact assessment should be required. For concentrated solar power in arid environments, dry cooling should be required.

5. The EU should consider requiring environmental impact assessment for facilities importing energy to the EU, either directly as electricity, or as electrofuels.

The regulatory issues of renewability and carbon accounting are important, but there is another equally difficult challenge confronting any attempt to develop an EU electrofuel industry. Just as for advanced biofuels, scaling up electrofuels will require large capital investments and a guarantee of value from policy to close the price gap to fossil fuels. Experience with advanced biofuels shows that mandates are not particularly well suited policy instruments for developing new technologies. Setting mandates instead of providing defined incentives is intended to provide the basis for industry to deliver environmental outcomes at the lowest cost possible, with different climate solutions competing in a compliance market. The theory is that under these systems higher-cost solutions will be outcompeted by lower-cost solutions, and emissions reduction goals can be delivered at minimum cost to consumers and taxpayers. By definition, there is a degree of uncertainty about the value of compliance in these market based mandates, because the value of compliance is determined by which compliance options are brought to market. The problem in the case of unproven technologies such as advanced biofuels or electrofuels is that it is difficult for investors to commit to 20 year investments in fuels that are more expensive than fossil alternatives unless they have a clear idea of the value of future policy incentives. Mandates with too much value uncertainty therefore structurally favour climate solutions that can be mobilised in the short term in response to known policy value (such as increasing production of used cooking oil biodiesel) over climate solutions that need to deliver returns over decades of uncertain future policy value.

European policy makers should seriously reconsider the policy tools that are available to promote embryonic industries, and seek support options that do better at giving the clearest possible value proposition for at least a decade ahead. Electrofuels are currently a relatively expensive climate mitigation option. If policy makers consider this cost to be justified given the benefits and long-term prospects, especially for modes such as aviation that lack obvious medium-to-long-term alternatives, then they need to provide policy support that will provide a solid guarantee of meeting those costs, or else investment will not happen. As it stands, it would be surprising if the proposed policy framework were adequate to deliver any significant investment and production before 2030.

Conclusion

Renewable electrofuels can have very low greenhouse gas intensities, lower associated environmental risk than conventional and even advanced biofuel production, could be used by transport modes like aviation that lack alternative technological decarbonisation options, and could theoretically be produced in large volumes. On the other hand, there is a lack of effective regulatory models to either guarantee environmental performance or drive industrial expansion, the cost of fuel production is likely to be several times higher than for fossil fuels for the foreseeable future, and while a large industry in the EU is theoretically possible it would require massive investment in additional renewable electricity generation, and put additional stress on electricity systems.

To quote (Bünger et al., 2014), given the cost and implications for the electricity system implicit in a large expansion of electrofuels, alongside any expansion of these technologies it is, "vital to explore all available options for the reduction of energy demand and increase of vehicle efficiencies", and to maximise the amount of electricity that can be efficiently delivered for electric drivetrain transport rather than delivered in the form of liquid fuels with large energy losses through the system. If electrofuels are to be a part of the 2050 energy mix, they ought to have a clear but subsidiary role alongside other technologies.

Even with electrification and efficiency improvements though, there will inevitably be a residual liquid fuel demand from transport even in 2050. It is unlikely that sustainable biofuels will be available in the quantities needed to replace fossil fuels in meeting this residual demand, and so there is a clear long-term opportunity for electrofuels to contribute to a more sustainable EU energy economy. Regulators, policy officials and stakeholders generally need to reflect carefully on the costs and benefits of driving electrofuel development, and develop a realistic vision for the role that electrofuels should be asked to play. If that role is to include a significant contribution to meeting transport energy needs by 2050, in aviation in particular, it will require commercial demonstration of these technologies within the coming decade, and clear measures to expand production beyond that. It will also require an honest appraisal of the costs involved in expanding electrofuel production, and a willingness to pass those costs through to transport consumers.

Given the 'polluter pays principle' of European law, it would not be politically or morally viable to ask taxpayers to bear the long-term cost of reducing the environmental footprint of any given transport mode. Meeting the costs of delivering 50% of energy from electrofuels could be expected to double the total fuel spend for EU aviation, and therefore it should be understood that doing so will not be possible without an impact on air fares. Similarly, a large use of electrofuels for heavy duty road and off-road transport would imply a significant increase in fuel costs for the relevant end-users. More than anything, before electrofuel production reaches a large scale it is vital that a regulatory framework should be put in place that guarantees that electrofuels are produced with additional renewable electricity, and that avoids the situation where double counting results in a situation where a growing renewable electrofuel industry incidentally erodes the environmental benefits of other legislation.

Contents

Glossary of abbreviations

CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CSP	Concentrating solar power
DME	Di-methyl ether
EIA	U.S. Energy Information Administration
ETS	Emission trading scheme
GDP	Gross domestic product
GHG	Greenhouse gas
ICAO	International Civil Aviation Organisation
ICE	Internal combustion engine
IRR	Internal rate of return
JRC	Joint Research Centre
kWe	Kilowatt of electricity
kWh	Kilowatt hour
LCA	Lifecycle analysis
LCFS	Low carbon fuel standard
LHV	Lower heating value
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MWe	Megawatt of electricity
MWh	Megawatt hour
NER300	'New Entrants' Reserve' EU funding program for low-carbon energy projects
PEM	Polymer-electrolyte membrane
RED	Renewable Energy Directive
REDII	Revised Renewable Energy Directive for the period 2021-2030
RFS	Renewable Fuel Standard
SOEC	Solid oxide electrolyser cell
toe	Tonne of oil equivalent
TRL	Technology readiness level
VAT	Value added tax
WTT	Well to tank

Introduction

Europe is in the process of decarbonising, and by 2050 has committed to have reduced its greenhouse gas emissions at least 80% below 1990 levels[3]. This will require almost complete decarbonisation of electricity generation, as well as deep cuts to emissions from transport and industry. Many analysts believe that European decarbonisation will have to be accelerated even faster than this to be consistent with targets under the Paris agreement[4]. Graichen (2016) argues that at least 95% decarbonisation of effort sharing sectors (including transport) is needed by 2050 if Europe is to avoid relying on uncertain negative-emissions technologies in the second half of the century.

While improvements to vehicle efficiency and the roll out of vehicle electrification offer partial pathways to transport decarbonisation, it is not at all certain that the passenger vehicle fleet will be fully electrified even by 2050. Heavy duty road transport is likely to be harder to fully electrify, shipping harder still, and aviation will continue to be almost entirely dependent on liquid fuels well into the second half of the 21st century. Both for any residual liquid fuel demand in road transport, and for shipping and especially aviation, deep decarbonisation will be difficult if not impossible without, the option of low carbon liquid alternative fuels in large volumes. Advanced biofuels provide one potential low carbon option, but are unlikely to be able to expand sustainably to meet the full decarbonisation opportunity (Searle & Malins, 2015). In this context, there is great prima facie appeal to the possibility of converting renewable electricity into liquid or gaseous transport fuels – fuels delivered in this way are referred to as 'electrofuels'. The production of renewable electrofuels using zero carbon renewable electricity appears to offer better greenhouse gas performance than biofuel production, with fewer sustainability concerns. It would turn much of the transport decarbonisation challenge into an extension of the electricity decarbonisation challenge, which the EU is arguably better prepared to deal with.

While the appeal is clear, the challenges are considerable. Industrial demonstration of the integrated processes required to produce electrofuels is in its infancy. Electrofuels are in a comparable position to that of advanced biofuels ten years ago, and face similar barriers to rapid expansion. Primary among the existing barriers is the high current cost of electrofuel synthesis. Electrofuels will not be competitive with fossil alternatives, even with significant levels of policy support, unless dramatic reductions in the cost of electricity and in investment costs can be delivered in the coming decades.

Electrofuels supplied for conventional vehicle engines also suffer from fundamental limits on overall efficiency when compared to the direct use of electricity in electric vehicles. The technology for the conversion of electricity to drop-in electrofuels is currently only about 40% energy efficient, meaning that less than half as much energy is finally delivered to vehicles via an electrofuel process as compared to direct battery charging. Electric powertrains are also more efficient than petrol or diesel power trains. According to Wolfram & Lutsey (2016), real world 2010 energy efficiencies for battery electric vehicles that were 3.4 times better than for petrol vehicles and 2.7 times better than for diesel vehicles. Even for hybrid electric diesel vehicles, the 2010 electric powertrain was 2.5 times more efficient. The overall use of electricity

3 https://ec.europa.eu/clima/policies/strategies/2050_en

4 E.g. http://www.caneurope.org/energy/climate-energy-targets

in an internal combustion engine vehicle via conversion to drop-in electrofuel is therefore about 5 times less efficient than the use of electricity directly in an electric powertrain vehicle. Given this stark efficiency differential, it is clear that where possible increased electrification is preferable to the use of drop-in electrofuels, and that electrofuels are best considered as an option for transport niches in which electrification is either not yet possible or has not yet been fully delivered.

This report reviews the status and prospects of the electrofuel industry in the EU, with a focus on power-to-liquids pathways that can produce drop-in fuel substitutes for road transport and aviation.

Electrofuel pathways

The term electrofuels can cover a range of technology pathways. The simplest electrofuel to produce would be hydrogen, for use either in fuel cells or mixed into the natural gas supply.[5] More complex chemical synthesis processes can be used to take hydrogen from electrolysis and produce drop-in fuels that could be used without modification by the existing vehicle fleet. The basic electrofuel production options are detailed below.

Power to H2

The fundamental step in any PtX fuel production pathway is the electrolysis of water to produce hydrogen and oxygen. The simplest use case for the produced hydrogen is to supply it directly, either for combustion or for use in fuel cells. Hydrogen could be mixed into the existing natural gas supply up to a blend of about 15% and supplied for existing gas combustion applications without any undue impact on end users (Melaina, Antonia, & Penev, 2013), although regional pipeline infrastructure would need to be tested for handling adjusted gas mixes. This supply model would not readily allow segregation into transport, and is not considered in detail in this report.

Hydrogen could also be supplied as a segregated fuel stream for use in fuel cells (whether for transport or for domestic and industrial applications). The potential for hydrogen fuel cell vehicles is extensively discussed elsewhere, and is not a focus of this report.

Power to methane

As an alternative to supplying hydrogen directly to end users, the chemical process of methanation could be used to combine hydrogen (H_2) with carbon dioxide (CO_2) to produce methane (CH_4). In the methanation reaction, H_2 and CO_2 are reacted in the presence of a catalyst (generally nickel) (Götz et al., 2016):

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$$

The produced methane could then be supplied through the gas grid, or liquefied/compressed

5 There are also other industrial and chemical applications for low-carbon hydrogen, such as in petroleum refining, but these uses are beyond the scope of this report.

for distribution. Given a significant number of vehicles capable of running on natural gas, this could make a significant contribution to transport energy supply.

Power to methanol

Given the limited number of natural gas vehicles in the current vehicle pool, and the challenges involved in developing distribution networks for gaseous fuels, power-to-liquids technologies have clear appeal over power-to-gas technologies from a transport perspective. One route to liquids production would be methanol synthesis (Schmidt, Zittel, et al., 2016):

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

In principle, methanol could be used directly as a transport fuel in low blends with petrol. Oxygen content limits of 7.8% by mass for EU transport fuels translate into a maximum methanol blend of 3% (Faberi & Paolucci, 2014), but given existing ethanol blending (which also introduces oxygen into fuels) this market is likely rather limited given present rules. The introduction of flex-fuel vehicles by manufacturers, able to run on a wider range of mixes of petrol, ethanol and methanol, could expand this market in future, creating up to 70 million tonnes of methanol demand from EU road transport (Faberi & Paolucci, 2014). This is not, however, currently considered likely in the European market.

Methanol to drop-in synthetic fuels

Given limits on methanol blending, for methanol synthesis to play a significant role in the EU transport energy supply would likely require further chemical processing to synthesise drop-in transport fuels from PtL methanol. This could be achieved through sequential processes of olefin synthesis, oligomerisation and hydrotreating, as detailed by Schmidt, Zittel, et al. (2016):

DME synthesis:	$2CH_3OH \rightarrow CH_3\text{-}O\text{-}CH_3 + H_2O$
Olefin synthesis:	$CH_3\text{-}O\text{-}CH_3 \rightarrow (CH_2)_2 + H_2O$
Oligomerisation:	$n/2\ (CH_2)_2 \rightarrow C_nH_{2n}$
Hydrotreating:	$C_nH_{2n} + H_2 \rightarrow C_nH_{2n+2}$

Schmidt, Zittel, et al. (2016) report that with the reaction tuned for maximum diesel production, it can produce up to 81% diesel and kerosene range hydrocarbons (alternatively, the production of diesel and kerosene could be almost eliminated in favour of petrol and LPG range hydrocarbons). The hydrotreated hydrocarbon outputs of this reaction chain could be blended directly into the existing fuel pool for diesel, petrol and/or jet fuel. Brynolf et al. (2017) similarly include costs for a methanol to gasoline route.

Power to Fischer-Tropsch synthetic fuels

The methanol route requires several sequential reactions. An alternative route, already applied for coal-to-liquids and gas-to-liquids technologies (Fasihi, Bogdanov, & Breyer, 2016), is Fischer-Tropsch (FT) fuel synthesis. Fischer-Tropsch synthesis produces paraffinic waxes from syngas (H_2 and CO). Carbon monoxide for the FT reaction can be produced by the reverse water-gas-shift reaction[6] from carbon dioxide and some of the hydrogen from electrolysis. The FT reaction is (Schmidt, Zittel, et al., 2016):

$$nCO + (2n+1)H_2 \rightarrow C_nH_{2n+2} + nH_2O$$

The products of the FT reaction are upgraded by hydrocracking into lighter hydrocarbons to meet the desired output hydrocarbon profile (Fasihi et al., 2016; Schmidt, Zittel, et al., 2016). Documented output fractions for gas-to-liquids FT processes range from 5 to 30% naphtha, up to 5% LPG and 65-85% mid-distillates (diesel and kerosene) (Fasihi, 2015), with up to 50% of the output volume as jet fuel (Albrecht, Schmidt, Weindorf, Wurster, & Zittel, 2013). De Klerk (2011) models a case for high temperature FT refining with jet fuel as 75% of the transport fuel output.

The hydrocarbons that could be upgraded to jet fuel will generally also be suitable for upgrading into road diesel. While producers will have a degree of flexibility regarding which output fuels to produce, the products will always include a mix of hydrocarbons including some amount of naphtha and road diesel in addition to produced jet fuel.

Co-production of synthetic fuels from biomass and power

A variation on the above technology pathways for electrofuels would involve the use of hydrogen from electrolysis as an additive to syngas from other sources, such as technologies for biomass-to-liquids through gasification.

Biomass from sustainably available wastes and residues has the potential to be substantially cheaper in energy terms than electricity. For instance, Turley, Evans, & Nattrass (2013) estimate a delivered price of 40-65 €/tonne for forest residues, which is equivalent to about 1 €cent/kWh (LHV). Biomass gasification will typically deliver a syngas with a molar ratio of about one to one between hydrogen and carbon monoxide molecules. In a 'conventional' gasification and fuel synthesis plant, this ratio would be increased to two to one by using the water gas shift reaction to convert CO into additional H_2.

The water gas shift reaction does not transfer chemical energy from CO to H_2 100% efficiently[7], and the water gas shift reactor incurs capital and operational expenditures, and so there may be efficiency savings to be achieved by adding hydrogen from other sources to syngas from biomass gasification, one option for which would be hydrogen from electrolysis (Hansen & Mogensen, 2011). In this case, the viability of the combined facility would be dependent on not only the electrolysis facility but also the biomass gasifier.

For a biomass-and-power to methanol case, Hansen & Mogensen (2011) find that operating a mixed system could deliver methanol for up to 20% less than a biomass gasification only system (although this is heavily dependent upon relative prices of electricity and biomass).

Electrofuels in this report

The electrolytic production of hydrogen for supply to fuel cells is extensively discussed in reports

6 The water gas shift reaction works in the opposite direction, reacting water with carbon monoxide to produce hydrogen, and is used in the production of hydrogen from natural gas.

7 About 14% of the chemical energy is lost as heat (Carbo et al., 2009; Waldheim, L. Nilsson, 2001).

on future potential for deployment of fuel cell vehicles, and therefore is not discussed here. As noted above, there are also intermediate cases, such as methanol that could be blended into petrol, or di-methyl ether (DME) for use in customised diesel engines. Both of these technologies have their advocates, and may have a role to play for niche applications or as a technological stepping stone towards production of true drop-in electrofuels. Nevertheless, given the need for customised engines, and the relatively low historical take of these fuel options in Europe, it is considered unlikely that either these fuels will ever provide a large fraction of EU transport energy. Throughout this report, we therefore primarily present results relevant to drop-in fuel production, either through FT-synthesis or for pathways that use methanol as an intermediate step, as it is likely that any large future electrofuel industry will need to produce drop-in fuel replacements.

Existing electrofuel facilities

Sustainable Transport Forum sub group on advanced biofuels (2017c) provides a review of existing pilot and demonstration electrofuels facilities within Europe. These facilities are detailed in Table 1. None of the existing facilities of which we are aware produce drop-in transportation fuels.

Table 1. Existing pilot and demonstration scale electrofuels facilities in Europe

Facility operator/ name	Country	Start-up year	Output electrofuel	Electricity consumption	Product output	Conversion efficiency	CO_2 source
Audi	Germany	2015	H_2	6.3 MW	3.5 MW	56%	Waste treatment biogas plant
BioCAT	Denmark	2016	CH_4	1 MW	0.56 MW	56%	Wastewater treatment plant
CRI	Iceland	2012	Methanol	6 MW	10 tonnes/ day	-	Geothermal plant flue gas
MefCO_2	Germany	Scheduled for 2018	Methanol	1 MW	1 tonne/ day	-	Power plant flue gas

Technology maturity of electrofuels

While there is considerable interest in the prospect for renewable electrofuels as a transport decarbonisation option, there are very few facilities demonstrating the concept as yet, and no demonstration scale facility in Europe of which we are aware delivering drop-in liquid transport electrofuels. Many of the component technologies have, however, been extensively demonstrated in other contexts. For instance, Schmidt, Weindorf, Roth, Batteiger, & Riegel

(2016) note that, "Upgrading the FT-derived crude product to jet fuel and other hydrocarbons comprises several process steps, notably hydrocracking, isomerization, and distillation. These processes are commonly used today at large scale in crude oil refineries as well as in CtL and GtL plants." Syngas produced by a combination of electrodialysis (for hydrogen) and reverse water gas shift (for carbon monoxide) processes should be relatively clean compared to syngas from biomass or fossil fuel gasification, which may provide an advantage for processing.

One way to understand the technological maturity of electrofuel technologies is the system of technology readiness levels. This is a system of 9 levels of technology deployment set by the European Commission, as shown in Table 2.

Table 2. Definition of technology readiness levels

Technology Readiness Level	Description
TRL 1.	basic principles observed
TRL 2.	technology concept formulated
TRL 3.	experimental proof of concept
TRL 4.	technology validated in lab
TRL 5.	technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 6.	technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 7.	system prototype demonstration in operational environment
TRL 8.	system complete and qualified
TRL 9.	actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)

Sustainable Transport Forum sub group on advanced biofuels (2017a) characterise the production of electromethane and electroliquids as having reached the 'early innovation stage', TRL 5-6. That means that the necessary technologies have all been demonstrated or at least validated, but there is not yet a demonstration of the system prototype. They predict that there will be no significant commercial production of renewable electrofuels until at least the second half of the 20s.

Schmidt, Weindorf, et al. (2016) are a little more positive about the technology readiness level of the methanol system, which they characterise as TRL 8, and provide a detailed breakdown of TRL for the component systems, as shown in Table 3.

Table 3. TRL of component technologies

Technology	TRL (today)
Water electrolysis	
Alkaline electrolyser	9
Polymer-electrolyte membrane electrolyser (PEM)	8
High-temperature electrolyser cell (SOEC)	5
CO_2 supply	
CO_2 extraction	
CO_2 from biogas upgrading, ethanol production, beer brewing, ...	9
CO_2 exhaust gas	
Scrubber with MEA	9
Scrubber with 'next generation solvent'	8
Absorption/electro-dialysis	6
Pressure-swing absorption (PSA)/Temperature-swing absorption (TSA)	6
CO_2 from air	
Absorption/electro-dialysis	6
Absorption/desorption (TSA)	6
CO_2 conditioning (liquefaction and storage)	9
Synthesis	
H_2 storage (stationary)	9
Fischer-Tropsch pathway	
Fischer-Tropsch synthesis	9
Reverse water gas shift (RWGS)	6
Hydrocracking, isomerization	9
Methanol pathway	
Methanol synthesis	9
DME synthesis	9
Olefin synthesis	9
Oligomerization	9
Hydrotreating	9

They state that, "Both PtL pathways (via Fischer-Tropsch or methanol) offer a high level of technology readiness." They continue, "While individual processes have been deployed at large scale, PtL full system integration is currently significantly progressed with the Fischer-Tropsch pathway demonstration plant by Sunfire in Dresden, Germany." While they characterise the individual processes in the FT electrofuel chain as having achieved a high TRL (8 or 9, except for the reverse water gas shift reaction required to produce carbon monoxide from carbon dioxide and hydrogen, which they characterise as TRL 6), some of the technologies that could improve the energy efficiency and economics of the process (such as SOEC electrolysis) still have a lower TRL status.

The production of jet fuel from FT synthesis has already been demonstrated and approved for use by ASTM. The jet fuel pathway via methanol, however, has not been demonstrated and has not yet been certified by ASTM for use on commercial flights. If the pathway via methanol were to be pursued, technical approval would be an important step before deployment could begin (Schmidt, Weindorf, et al., 2016).

Electrofuels for transport

As discussed above, the context for policy interest in developing electrofuels is that for decades to come, EU transport is expected to continue consuming large quantities of liquid fuels, and that in the absence of sustainable alternatives these will be fossil fuels. This demand will continue, albeit at a decreasing level, for both gasoline and diesel engines in road transport, as well as from the aviation and marine modes, which will take a greater and greater share of liquid fuels. While electrofuel technologies have the potential to produce a range of different output molecules, the simplest answer in terms of infrastructure and engines is to produce electrofuels that can be blended into existing transport fuels on a drop-in basis. In this report, we are therefore focused on those options that could be used in existing engines.

For passenger vehicles in particular, but also for heavy duty road vehicles and any other modes that can eventually be electrified, it is relevant to consider the comparative advantages and disadvantages between the use of electricity in electrofuel production, against options to supply electricity directly for use in electric vehicles. There is no question that the overall system of electricity supplied directly through the grid to electric vehicles is more energy efficient than a system of electrofuels supplied to internal combustion engines. The electric motor itself is a more energy efficient drivetrain, and as we will discuss in more detail below there are considerable energy losses in conversion of electricity to electrofuels. It is therefore best not to consider vehicle electrification and electrofuels as competing climate solutions, but as complementary ones. The increased adoption of electric drive zero emissions vehicles appears to be a good solution both for transport decarbonisation and for air pollution reduction. For instance, Bünger et al. (2014) note for Germany that, "only a shift in focus towards battery or fuel cell electric vehicles will allow to achieve … [the target of] a 40% reduction of final energy consumption in transport by 2050 in reference to 2005." Electrofuel production for internal combustion engines is best thought of as a technology to reduce the impact of residual liquid fuels combustion during the long transition to electric mobility, rather than an endpoint in itself. Given that this transition will take many decades, there is still potential for electrofuels to make a considerable contribution to reducing greenhouse gas emissions from transport.

Electrofuels for aviation

In principle, electrofuels could be used for a range of applications and in any transport mode. However, there is a particular interest in the potential of electrofuels for aviation, given the lack of electrification options available for aeroplanes in the medium term. The International Air Transport Association (IATA) has nominally adopted ambitious decarbonisation targets for the sector to reduce 2050 CO_2 emissions by 50% compared to 2005[8] which would require profound changes in aviation efficiency and fuel supply to be delivered between now and 2050.[9] Compliance scenarios for these targets generally rely on an extremely large contribution from alternative fuels (e.g. Booz and Company, 2011; ICAO Secretariat, 2017b). It is sometimes assumed that biofuels are the only viable option to produce low-carbon alternative aviation fuel at scale. However, delivering the necessary volumes sustainably from biofuels alone is likely to be challenging at best (Malins, 2011). Additional pathways for alternative aviation fuel production are therefore of considerable interest.

Aviation fuel is chemically similar to road diesel fuel (the molecules from fuel synthesis that can be used for aviation fuel could also be used for road diesel blendstock), and the chemical processes that allow synthesis of aviation kerosene are very similar to those that allow synthesis of road diesel, such as FT-synthesis and methanol conversion. Most fuel synthesis processes naturally produce a range of hydrocarbon molecules of different lengths. Maximising diesel or jet fuel yield requires tuning processes to preferentially produce the correct length of hydrocarbon for a given application. In general, it is not possible to produce 100% molecules of any given category from a fuel synthesis process, so industrial PtL processes will yield a range of molecules that may be more suitable for gasoline, diesel or aviation kerosene use. The production of jet fuel from renewable power requires the same FT synthesis steps as are required for biomass FT, and also GtL and CtL, which are well demonstrated technologies. Schmidt, Weindorf, et al. (2016) observe that:

> *The share of products from the Fischer-Tropsch synthesis suitable for jet fuel use is about 50 to 60 % (by energy). Oligomerization can be applied for the processing of the C3 and C4 fraction from Fischer-Tropsch synthesis to increase the share of liquid hydrocarbons and to meet the Jet A-1 specifications.*

Historically, the market for alternative fuels in aviation has been less well supported than the market for alternative fuels in road transport. The exemption of jet fuel from fuel taxation means that excise tax incentives have not been available for aviation fuel, while major alternative fuel support programmes (e.g. LCFS, RFS, and RED) tended not to support the supply of alternative fuels for aviation in their early years. This picture has been somewhat changed over the last decade, and the supply of alternative fuels in aviation is increasingly eligible for the same type of support measures as are offered to alternative road fuels. Nevertheless, notwithstanding a steady stream of test and demonstration flights running on renewable aviation fuel, the total volumes of alternative fuels deployed for aviation has been only a fraction of the volume consumed in road transport.

From a business perspective, the fundamental question is whether aviation provides a

8 http://www.iata.org/policy/environment/Pages/climate-change.aspx

9 While there is no question that these targets are ambitious in practical terms, it is also appropriate to note that the level of overall decarbonisation ambition for aviation falls far short of that for other EU transport modes. Where EU road transport emissions will be at least 80% reduced compared to 1990 levels by 2050, the proposed ICAO 'inspirational vision' for 2050 (ICAO Secretariat, 2017a), which assumes 50% sustainable alternative fuels, would deliver 2050 CO2 emissions about three times higher than in 1990. If including non-CO2 global warming effects (notably induced contrails and cloudiness), the sector's total climate impact will be between 5 and 10 times greater in 2050 than it was in 1990 (author's calculation).

more appealing market than road transport for alternative fuels. While some value will be provided to alternative jet fuel by the 'market based measure' (CORSIA) for global aviation decarbonisation[10], it seems likely that the implied carbon dioxide price supported by the scheme will be closer to the current relatively low carbon price under the EU ETS than the much higher value offered by existing policies supporting alternative fuels. ICCT (2017) anticipates that the price of offsets under CORSIA will be no more than 20 $/tCO_2e$ by 2035, as the system is currently structured. Nevertheless, as progress continues towards 2050 decarbonisation obligations under the Paris Agreement, there will be a growing imperative for aviation to deliver on its commitments. This may mean that in future regulators require the aviation industry to support a higher carbon price than is set for other sectors – whether directly through a defined carbon price, indirectly through a cap and trade mechanism on aviation emissions, or implicitly through renewable fuel mandates. In that case, aviation could eventually become an appealing market for electrofuels. Fortunately, the technologies that would need to be developed to supply drop-in transport electrofuels to road transport, especially for diesel vehicles are essentially similar to the technologies that would be needed to produce electrojet, and a long-term expectation that electrofuels should be used in planes can therefore still be completely consistent with short term programmes that allow the market to decide which mode to supply electrofuels to.

When considering any alternative fuels as a potential solution to the climate impact of aviation, it is important to recognise that much of the radiative forcing associated with the aviation industry is due not to combustion of fossil fuels, but to non-CO_2 effects, primarily contrails and induced cloudiness. It is estimated that these non-CO_2 effects cause roughly as much warming again as the combustion of fossil fuel for aviation, when assessed on a 100 year basis (Hassink, 2012). Alternative fuels are not a potential solution to this component of aviation's' climate impact (although there is some possibility that the use of cleaner burning synthetic fuels could marginally reduce these non-CO_2 impacts, as discussed further below in the section on lifecycle analysis). Additional measures would therefore need to be developed in combination with increased availability of alternative fuels if the full global warming impact of a growing aviation sector is to be effectively controlled.

Renewability and carbon performance of electrofuels

The drive to develop an electrofuels industry is predicated on environmental objectives, and in particular climate objectives. That means that in order to be worth developing, electrofuels must have low lifecycle greenhouse gas intensity compared to the use of fossil transport fuels.

Electrofuel production processes are not 100% efficient, as will be discussed further below. In fact, twice as much electrical energy is required to be input to production of drop-in transport electrofuels as is delivered in fuel energy. This means that, to a rough approximation, the greenhouse gas intensity of a transport electrofuel will be about twice the greenhouse gas intensity of the electricity used to produce it. For electrofuels to deliver on climate objectives, they must therefore use very low-carbon renewable electricity.

While this is a fairly simple conclusion to draw, defining in regulatory terms what it means for electrofuel production to 'use' low-carbon renewable electricity is more complicated. For instance, is it possible to preferentially supply renewable electricity through the grid to

10 https://www.icao.int/environmental-protection/Pages/market-based-measures.aspx

an electrofuel producer from a distant power generation facility? Current EU legislation (European Parliament, 2009) states that accounting cannot be done on that basis, and must instead use the average carbon intensity and renewability of grid electricity (at national or EU level). Proposed revisions to this legislation would allow for utilised electricity to be counted as renewable if a renewable power generation facility is connected directly to an electrofuel production facility (European Commission, 2016b). Even in this case, however, the interaction between different policy tools may complicate the picture – what if adding new renewable power capacity in one location allows additional natural gas burning elsewhere? Several commentators (e.g. Bracker, 2017)invoke the principle of 'additionality', that the renewable electricity used for electrofuel production must be additional to any renewable electricity that would be produced had that electrofuel plant never been opened.

This is not an academic question only – if the renewability and greenhouse gas intensity of electrofuels are badly regulated, there is the real risk that the EU could invest billions in developing a new industry, without actually reducing the EU's overall greenhouse gas impact. These issues are discussed in more detail, with accompanying recommendations, in the body of the report.

About this report

This report was commissioned from Cerulogy by the Brussels-based non-governmental organisation Transport and Environment, to provide an overview of the status and prospects of renewable electrofuels for European transport. In the sections below, we review the economics of electrofuel production. We consider whether electrofuels could play a role in handling intermittency from renewable electricity production, and whether the economics of electrofuels could be improved by providing some sort of grid balancing service by operating electrofuel production facilities only when the supply of renewable electricity is relatively high. We consider the implications of a growing electrofuel industry for power demand in Europe, for different levels of fuel production, and the overall cost implications of developing an industry scaled to meet different fractions of transport energy demand. We consider the environmental impacts of electrofuel production, especially as compared to the impacts of biofuels as an alternative source of low-carbon liquid fuels, and discuss what environmental safeguards might be appropriate in legislation to accelerate electrofuel production. Finally, we discuss what might be required from a policy framework to encourage investment in electrofuel production while guaranteeing environmental benefits from the sector.

Note on terminology

The fuels considered in this report, fuels produced by electrolysis of water and subsequent chemical processing, are referred to in the literature by various terms. Processes that produce gaseous fuels are referred to as 'power-to-gas' or PtG, while those that produce liquid fuels are referred to as 'power-to-liquids' or PtL. PtG and PtL can be grouped together and referred to generically as power-to-X fuels, or PtX. These fuels may also be referred to generically as 'e-fuels' or as 'electrofuels'. In the specific case of PtX fuels produced using solely renewable electricity for the electrolysis[11], European legislation refers to such fuels as 'renewable fuels of non-biological origin', which is sometimes abbreviated as RFNBOs, RFoNBOs or REFUNOBIOs.

While our focus in this report is on the case of fuels produced using entirely renewable electricity, much of what is discussed is applicable both to the renewable case (RFNBOs) and the generic case. If electrofuels are produced using electricity that would otherwise be supplied to the EU electricity grid, identifying renewability of the produced fuels will depend on the implementation of an effective regulatory regime that ensures that electrofuels are supplied with electricity that is genuinely additional, i.e. electricity that would not have been generated if not for the existence of electrofuel production facilities. For this reason, and because this report can be relevant outside the EU regulatory context, we will primarily use the term 'electrofuels' to refer generically to fuels synthesised from hydrogen produced by electrolysis. Where it is important to distinguish the renewable origin, we will use the term 'renewable electrofuels'.

Note on prices

In this report, many values are given in Euros. Unless otherwise stated, these values should be

11 The issue of when and how to define the input electricity as renewable is addressed further later in this report.

interpreted as inflation adjusted values in 2015 Euros, i.e. future prices are quoted at current values. Where the reports quoted have used slightly different baseline years (e.g. if 2005 or 2010 euro values are used) these have not generally been adjusted, as the impact of inflation over such periods is relatively small.

Note on carbon pricing and policy

At various points in this report, we discuss the level of carbon [dioxide][12] price or 'implied carbon [dioxide] price' required to make a project commercially viable. Support for climate-friendly technologies can be delivered in a variety of ways. Current tools include renewables mandates, carbon trading schemes, tax incentives, grants and loan guarantees, research and development support and so on. Alternative transport fuel support in the EU is provided largely through the renewables-in-transport mandate of the Renewable Energy Directive, rather than an explicit carbon pricing mechanism (although in Germany, implementation of the Fuel Quality Directive results in a more explicit carbon pricing signal). When we say that a certain carbon price is required, we mean that based on our understanding of cost and lifecycle carbon emissions for a given technology, it would need a bundle of government support of equivalent value to that derived from imposing a certain carbon price. It is not the place of this report to debate whether carbon pricing, renewables mandates or other tools are the most effective. It is, however, important to understand that an incentive for new technology development is limited by the level of confidence investors have that its value will remain constant (or better). As discussed by Miller et al. (2013), a policy tool with a high nominal value can have almost no value to investors if there is no confidence it will last more than a year.

When we suggest required carbon prices in this report, they are the implied carbon prices that would need to be put in a balance sheet to justify an investment. By implied carbon prices, we mean the equivalent value of a given alternative fuel production incentive when convrted into CO2 abatement price terms. The undelrying policy could be a mandate, cap and trade scheme, carbon tax, GHG intensity reduction requirement etc. Depending on the quality of the incentive framework, therefore, to deliver an investment on the basis of an ***expected*** 500 €/tCO_2e carbon price might require a policy that is ***intended*** to provide a value of 1,000 €/tCO_2e or more – the value to an investor is always discounted to some extent for uncertainty compared to the rationally expected carbon price for any given policy.

12 Always when we refer to 'carbon price' we properly mean 'carbon dioxide abatement price'.

Economics of electrofuel production

Table 4. Examples of projected production costs for PtL electrofuels (€/tonne)

Study	Electrolysis[1]	Pathway	FT jet/diesel pathway		Methanol to jet/diesel pathway	
			Short (~2015)	Long (~2050)	Short (~2015)	Long (~2050)
(Schmidt, Weindorf, et al., 2016)[2]	Low temperature	*Direct air capture*		1,841		1,719
		Concentrated CO_2 source		1,352		1,206
	High temperature	*Direct air capture*		1,675		1,671
		Concentrated CO_2 source		1,144		1,155
(Schmidt, Zittel, et al., 2016)[3]	Low temperature	*EU*	6,911	3,559	6,626	3,352
		Imported with concentrating solar		2,407		2,278
	High temperature	*EU*	7,467	3,054	7,402	3,067
		Imported with concentrating solar		2,058		2,071
(König, Baucks, Dietrich, & Wörner, 2015)	Low temperature	*Offshore wind*	3,145			
(Dimitriou et al., 2015)	Low temperature	*Small (0.5 MW)*	23,105			
		Medium (500 MW)	2,925			
		Large (900 MW)	1,755			
(Brynolf, Taljegard, Grahn, & Hansson, 2017)	Low temperature	*Electricity at 0.05 Euro/kWh*	1,511-8,955 (central 2,700)	1,279-3,954 (central 2,100)	1,860-12,211 (central 3,300)	1,511-5,000 (central 2,500)

1. Current electrolysis technologies (alkaline and PEM) are 'low temperature'. SOEC electrolysis operates at 'high temperature' and may allow efficiency improvements in future. See 'hydrogen from electrolysis' section below.

2. This study considered jet fuel production, but the cost assessment is equally applicable to diesel fuel.

3. This study considered diesel fuel production, but the cost assessment is equally applicable to jet fuel.

For any renewable alternative to fossil energy, the rate of adoption and deployment is dependent on the costs of the technology, and whether it can be competitive with the fossil competition, given access to any available government support. This is certainly a key issue for the potential electrofuel industry. For instance, Schmidt, Weindorf, et al. (2016) anticipate that in 2050 the cost of the lowest cost pathway for electrofuel jet fuel would be 40% higher than the top end of their jet fuel reference price range (1,144 €/t vs. 825 €/t), commenting that, "The projected cost for the production of PtL fuels derived from renewable electricity is significantly higher than the current 2016 jet fuel price." Cost estimates from the literature for various electrofuel pathways (€/t) are shown in Table 4.

Given that climate policies can be expected to significantly reduce oil demand over the coming decades, it cannot be assumed that underlying fossil fuel prices (excluding any carbon pricing and related policy) will increase to 2050, and indeed they may well fall (Summerton et al., 2016). Based on the cost estimates in the literature it will be impossible for electrofuels to compete with liquid fossil fuels except with substantial policy support, even if significant cost reductions are delivered over time. This price differential could be closed by the explicit or implicit imposition of a carbon price[13] on fossil fuels (or, similarly, through implicit or explicit subsidies for electrofuels).

The EU weekly oil bulletin for 18 September 2017[14] reports pre-tax retail diesel prices in the EU member states ranging from 550 (Slovenia) to 820 (Sweden) €/t. The lowest cost of production for diesel/jet fuel given in Table 4 is 1,144 €/t (Schmidt, Weindorf, et al., 2016). Taking this as a low estimate of future electrodiesel price, and assuming a lifecycle greenhouse gas intensity for electrodiesel of 5 gCO_2e/MJ, then making electrodiesel competitive with the most expensive current EU fossil diesel prices would require a carbon price of at least 83 €/tCO_2e. For the lowest current EU fossil diesel prices, a carbon price of at least 150 €/tCO_2e would be required. These carbon prices are consistent with the order of magnitude of the value provided by existing advanced biofuel support policies (Peters, Alberici, Passmore, & Malins, 2016), suggesting that European legislators may be willing to provide the sort of policy signals that would in principle support the supply of renewable electrofuel by a mature industry.

This said, there are vital caveats that must be made. Firstly, these are the required carbon prices required for the lowest reported production cost for future electrofuel (Schmidt, Weindorf, et al., 2016), which is based on relatively cheap electricity (4 €cent/kWh) and debt (4%), and on significant economies of scale and extensive cost reductions through innovation. If instead of this very low estimate, we consider the average predicted production cost for FT electrofuels in 2030 given by the reference scenario in Brynolf et al. (2017) (2,100 €/toe), then the required implied carbon price would be at least 330 €/tCO_2e to compete with the highest prices EU diesel, and at least 400 €/tCO_2e for the lowest.

Schmidt, Zittel, et al. (2016) predict that production costs can be halved by 2050, but still find even higher costs for production from EU electricity, in excess of 3,000 €/t for both the FT pathway and the pathway through methanol synthesis. At this cost level, the implied carbon abatement price from policy support would need to be in excess of 600 €/tCO_2e (Figure 2). This is well in excess of carbon price levels that most policy analysts expect to be acceptable, even in 2050. For instance, the European Investment Bank uses a 'high' scenario carbon price of about 230 €/tCO_2e for 2050, and a central projection of 120 €/tCO_2e, while the *EU Reference Scenario 2016* (European Commission, 2016a) anticipates an ETS carbon price rising to 90 €/tCO_2e by 2050. Acceptable costs for transport decarbonisation can be expected to be higher than ETS costs, but not indefinitely so.

13 The values given in this report as carbon prices are strictly speaking prices per carbon dioxide equivalent tonne of greenhouse gas emissions.

14 https://ec.europa.eu/energy/en/data-analysis/weekly-oil-bulletin

Secondly, the reduction of costs forecast between now and 2050 in the studies considered is predicated on a gradual expansion of electrofuel production, with cost savings and efficiencies being achieved as experience increases. In the cost modelling by Schmidt, Zittel, et al. (2016), the halving of production costs projected by 2050 is based on analysis that assumes that electrolysis investment costs will reduce by 13% every time overall production of electrolysed hydrogen doubles. In the scenarios analysed by Schmidt, Zittel, et al. (2016) the EU achieves 100% renewable energy in transport by 2050, which requires a massive expansion of hydrogen production for electrofuels. The resultant cost estimates (Figure 2) therefore include considerable savings associated with the rapid growth of the industry. If the industry grows more slowly, costs could not be reduced so quickly.

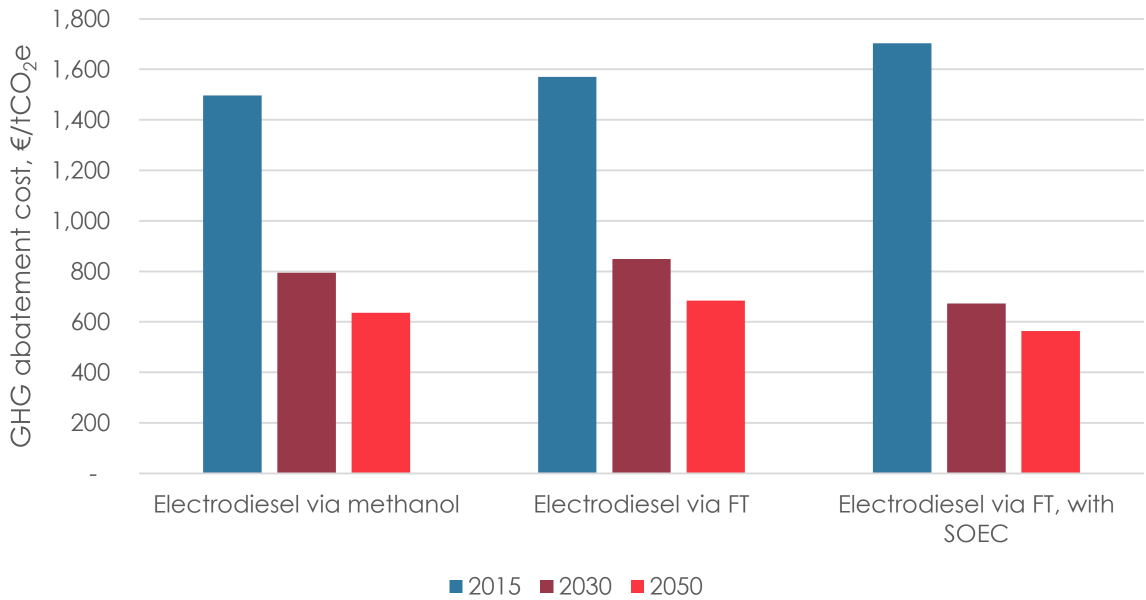

Figure 2. Predicted cost of carbon abatement with electrofuels (Schmidt, Zittel, et al., 2016)

For rapid growth to happen in the near term, policy makers must not only be willing to provide support worth hundreds of €/tCO_2e abated in 2050, but must also be willing to provide support with a much higher value in the near term. For the current average estimate for current production in the reference scenario from Brynolf et al. (2017), a carbon abatement price of over 1000 €/tCO_2e would be required to make production viable. Even the 2050 production cost estimates for drop-in electrofuels are comfortably above near-term cost estimates for advanced biofuels (Peters et al., 2016; Sustainable Transport Forum sub group on advanced biofuels, 2017b). The support framework currently proposed for electrofuels in the RED II (discussed further below) would have them counted towards the same renewable energy in transport target as advanced biofuels. Given anything but the very lowest production cost estimates from the literature, it seems highly likely that electrofuels will struggle to attract investment or make headway if competing for policy support with the advanced biofuel industry.

Division of costs

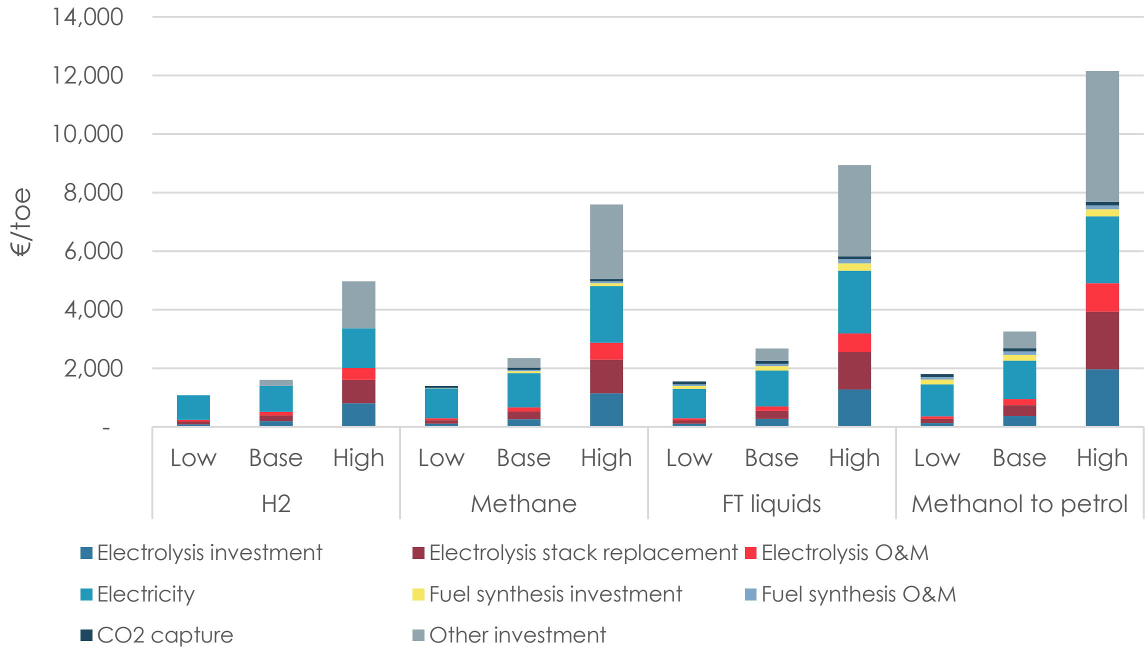

Figure 3. Division of costs for various fuel pathways in 2015

Source: Brynolf et al. (2017) for modelled facility with: PEM electrolyser; 5 €cent/kWh electricity; small scale; CO_2 from industrial point source; capacity factor 80%; 5% interest rate.

Figure 3 provides an illustration of the way that the costs of electrofuel production breakdown for different cost assumptions, using 2015 values from Brynolf et al. (2017). The base scenarios represent the average values from the literature, while the low and high use the lowest and highest literature values respectively. It can be seen that in all cases the cost of electricity for the electrolyser (priced at 5 €cent/kWh) is a significant term, at least 40% in all the base cases. The investment and operation costs associated with the electrolysis are also significant terms for many of the cases. This observation is echoed by Bünger et al. (2014), who state that, "the utilisation of PtG is associated with two decisive cost factors, namely electrolysis investment costs and the costs for electricity." Schmidt, Zittel, et al. (2016) similarly assert that, "PtX costs are dominated by electricity costs and fuel specific plant efficiencies." That paper also concludes that, "to achieve cost parity (excluding taxes) with today's fuel costs (including taxes), renewable electricity costs of the order of 3 €cent/kWh are required."

In the 'high' scenarios there are also significant costs ascribed to 'other' plant investment. It is not always clear what this other investment refers to, but it may include hydrogen storage and grid connectivity costs. The costs of carbon dioxide capture and fuel synthesis are never large compared to other costs associated with electrofuel production, in this modelling. For atmospheric capture, the CO_2 cost would be much higher, but still not a dominant term in the cost model. Other studies give similar results – electricity cost dominates the production cost unless electricity prices are extremely low, or investment costs are very high relative to output (e.g. for small first of a kind demonstration plants).

In the following sections, we discuss in more detail the cost of specific parts of the electrofuel production process.

Cost of electricity

The electricity input for electrolysis is a major component of the cost profile of electrofuel production – more than 50% of the overall production costs for all 2030 technology options considered in the reference case by Brynolf et al. (2017), and 75% or more of the projected 2050 costs for EU electroliquids production in Schmidt, Zittel, et al. (2016). Figure 4 shows the contribution of the cost of electricity for electrolysis to electrofuel price for a range of electricity prices and overall system efficiencies, for the case of FT electrodiesel. Even for a system with a high overall conversion efficiency of 60% and an electricity price of 2.5 €cents per kWh, the cost of the electricity inputs alone is more than 500 euro per tonne of fuel produced. For an electricity price of 10 €cents per kWh and overall conversion efficiency of 40%, the contribution of electricity price to overall cost is over 3,000 euro per tonne of electrodiesel. The reported average EU pre-tax electricity price to large industrial consumers in the second half of 2016 was 11.2 €cents per kWh. For an electricity cost above 7 €cent per kWh, it would be almost impossible to deliver FT electrofuels for less than 2,000 Euros per tonne, even for the most efficient possible plants (as electricity alone would add costs of at least 1,500 Euros per tonne).

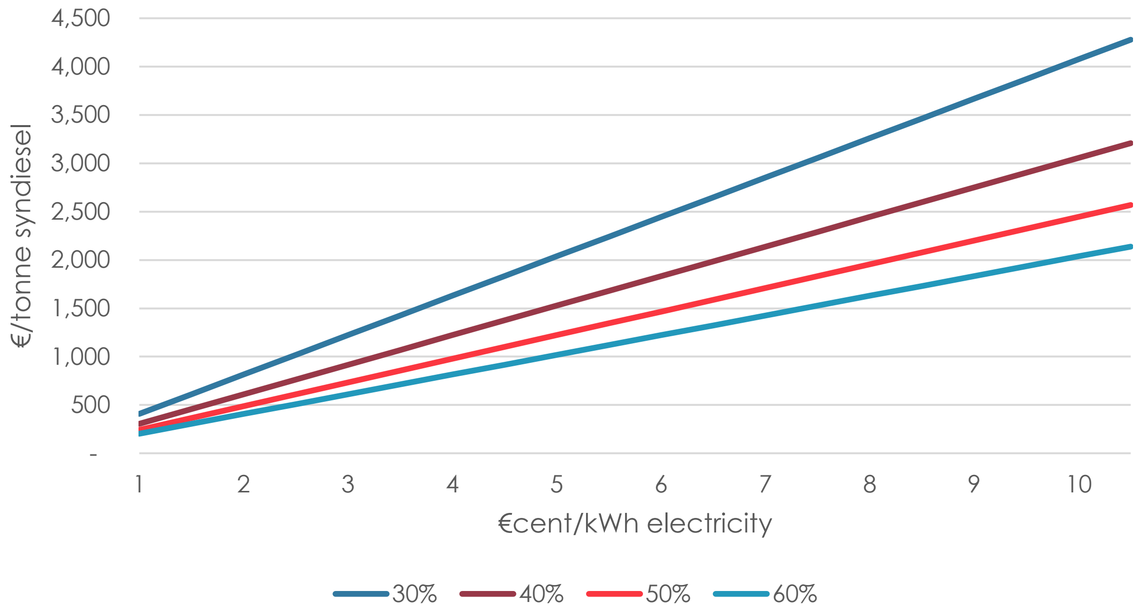

Figure 4. Contribution of electricity costs to cost of electrodiesel via Fischer-Tropsch synthesis, for overall electricity conversion efficiencies from 30% to 60%

Grid electricity prices

Electrofuel producers will experience different electricity prices depending on their relationship to the grid. For facilities directly connected to renewable power generation sites and disconnected from the grid, the price of electricity would be driven by the capital and operational cost of electricity generation. However, for facilities that are grid connected and (for instance) using some sort of tradable renewability certificate to show renewability, or that are directly connected to an independent renewable power facility that is also grid-connected and able to sell to the grid, electricity prices paid by the facility will be affected by grid prices. While grid electricity prices are affected by the cost of renewable electricity generation, they are also affected by transmission costs, the cost of generation of other forms of electricity and the costs of maintaining adequate spare capacity to deal with demand surges/supply shortfalls. The cost of renewable electricity generation is discussed further in the next section.

The current price of electricity to industrial users depends somewhat on the level of consumption of the customer. A 'demonstration' scale electrofuels facility might have a 1MW electrolysis capacity, and run for 4,000 hours per year. This would give an annual electricity consumption of 4,000 MWh, referred to as 'Band ID' electricity consumption in Eurostat. A 100 MWh facility running for 8,000 hours a year would have an electricity consumption of 800,000 MWh, putting it in the category of very large industrial consumers of electricity, 'Band IG'. Figure 5 shows industrial electricity prices across Europe, excluding VAT and other reclaimable taxes (values from Eurostat for second half of 2016). The data for the largest consumers (over 150,000 MWh per year, band IG) is not included as it is only available for some countries.

The EU average industrial electricity price for smaller industrial consumers on the scale of a demonstration electrofuels plant is about 10 €cent per kWh. For larger consumers, the price is closer to 7.5 €cent per kWh. The lowest price to large electricity consumers was in Sweden, 4.45 €cent per kWh. For a 40% overall efficiency of FT electrofuel production, achievable with low temperature electrolysis, this would contribute 1,360 €/toe to the cost, making fuel synthesis at a cost below 2,000 €/toe relatively achievable. Many commentators anticipate moderate short to medium term increases in electricity prices, partly due to the need to expand renewable electricity generation capacity and develop accompanying infrastructure. For instance, reference case modelling by the European Commission (European Commission, 2016a) anticipates EU after-tax electricity prices to consumers rising by 32% between 20010 and 2030, and the EU Energy Roadmap 2050 (European Commission, 2011) anticipates after-tax consumer electricity price increases of 41-54% between 2010 and 2030[15]. While the retail price certainly overstates prices available to large industrial consumers, it will be very difficult to deliver financial returns on electrofuels unless electricity prices go quite significantly down, not up. There is no compelling basis of which we are aware to indicate that precipitous reductions in the price of grid electricity to industry should be anticipated in the next one or two decades, which suggests that developing successful electrofuel business models will be very difficult unless lower cost electricity supplies can be secured.

15 Both sets of modelling then expect modest price reduction to 2050, except in the case of the high renewable energy scenario from the 2050 Roadmap, in which the cost of additional capital investment and grid balancing result in 2050 prices that are 82% above 2010 prices.

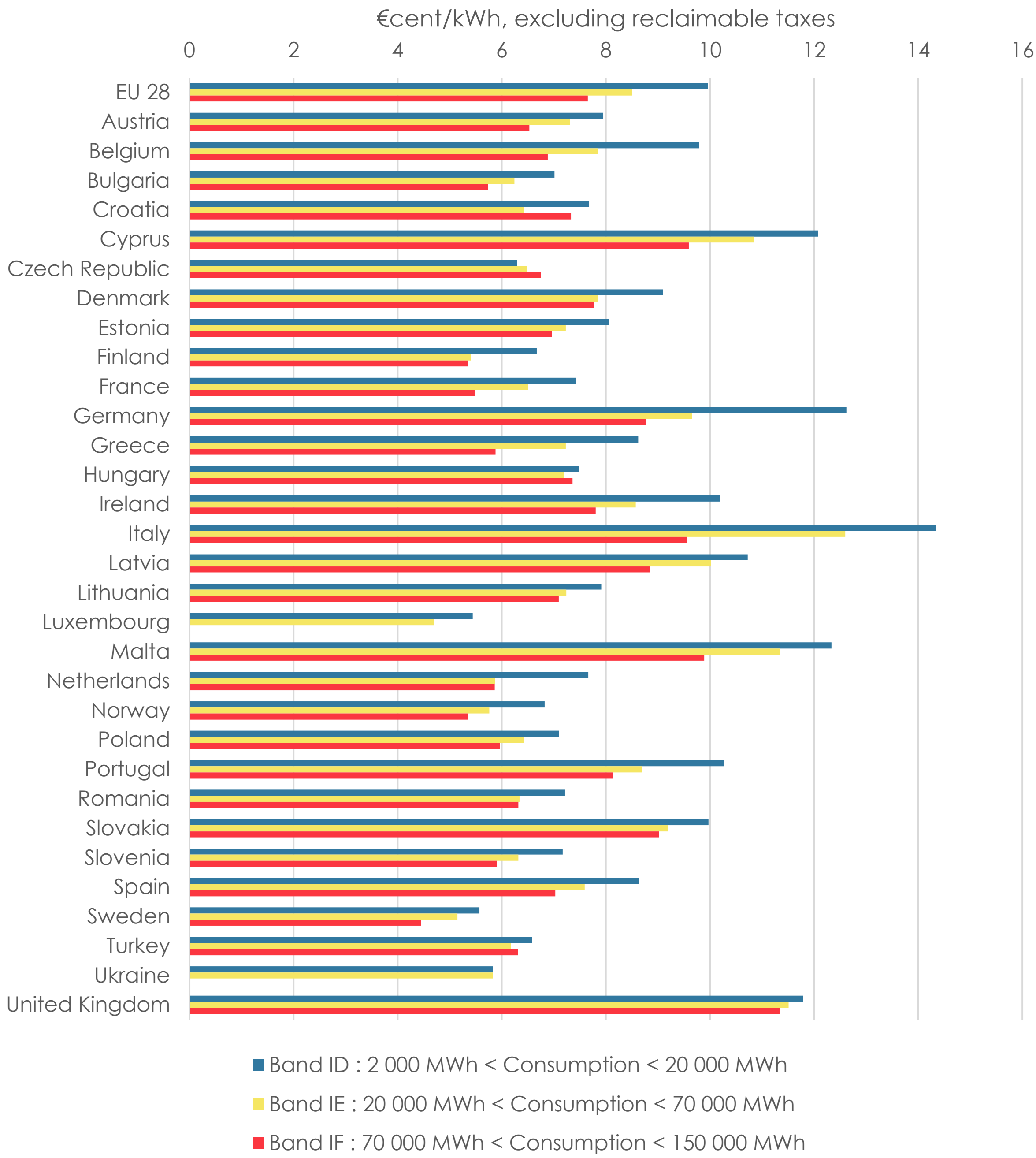

Figure 5. Average industrial electricity prices in Europe, second half of 2016

Source: Eurostat data table nrg_pc_205

Renewable electricity generation

In principle, one way for electrofuels producers to lock in lower prices would be to develop connected renewable electricity generation facilities, if such facilities could undercut costs of electricity from the grid. The downside of relying on a single renewable power generation facility is that potential full-capacity operational hours of the electrolyser will be limited by intermittency in generation. For solar power, operation would be limited at night or in cloudy conditions. For wind power operations would be limited on still days. Figure 6 provides an illustration of the impact on overall electrofuel production costs of reducing the number of operational hours in a year, given renewable electricity at 7 €cent/kWh (authors model based on use of expected 2030 values from Brynolf et al. (2017), with CO_2 captured from a point industrial source). Issues of intermittency in local renewable electricity generation might be managed to some extent through a mixed wind/solar power supply or by the use of energy storage (e.g. Schmidt, Zittel, et al. (2016) identify concentrating solar power with thermal overnight energy storage as a promising option).

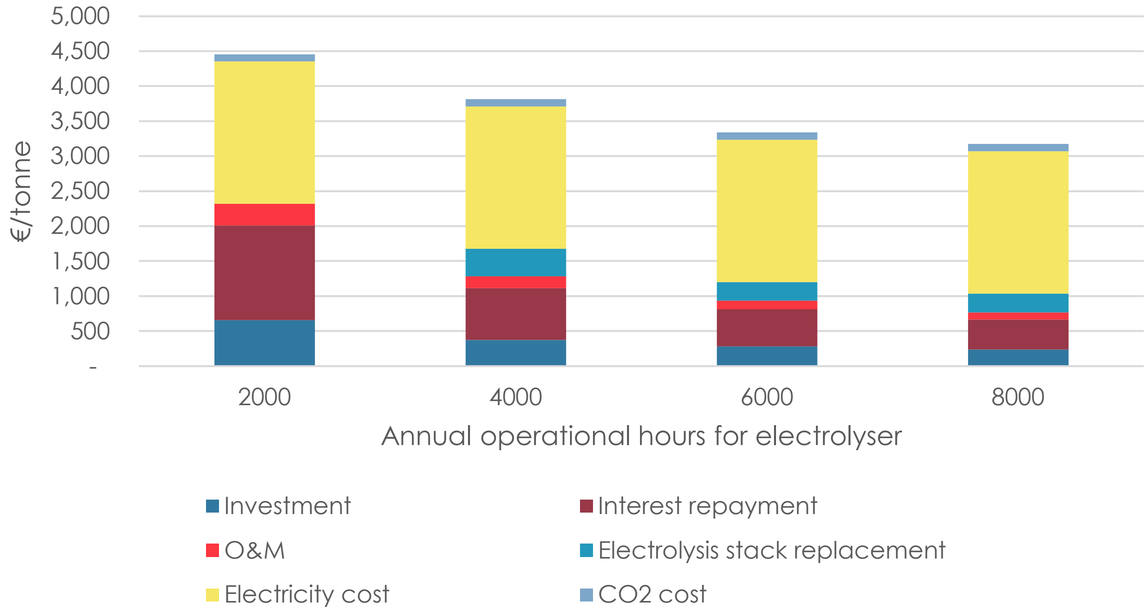

Figure 6. Illustration of impact on overall production costs of reducing hours of electrolyser operation

Source: Author's calculations

Renewable electricity generation costs below 7 €cents are currently not readily achievable in most of the EU, although costs can be expected to fall over time. Figure 7 shows average projected cost of production of renewable electricity in the EU from Schmidt, Zittel, et al. (2016). Currently, the cost of electricity from onshore wind and PV is around 8.5 €cents per kWh. In the U.S., the Energy Information Administration predicts average production costs for new renewables entering service in 2022 of 4.8 €cent/kWh for onshore wind, and 6.3 €cent/kWh for solar PV (EIA, 2016). In the UK, the latest round of renewable electricity support auctions[16] resulted in contracts for offshore wind power at 6.4 €cent/kWh (BEIS, 2017). Schmidt, Zittel, et al. (2016) report that EU renewable generation costs should fall towards 6 €cents per kWh for onshore wind and 5 €cents per kWh for PV by 2050 (Figure 7), and for Mediterranean countries anticipate PV electricity costs below 4 €cent per kWh by 2050.

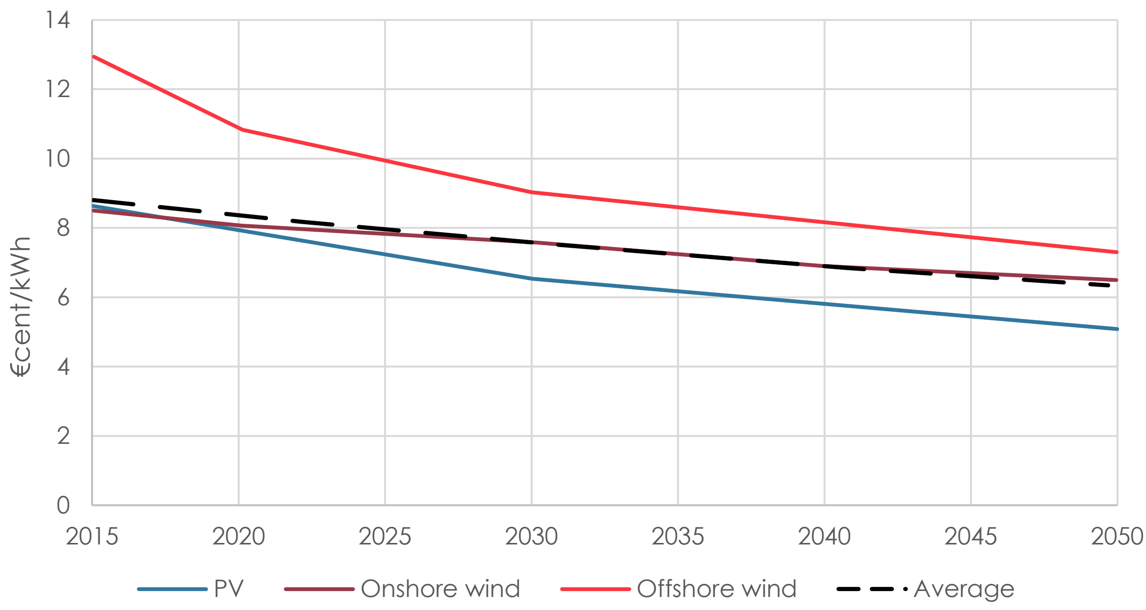

Figure 7. Projected average EU renewables prices to 2050

Source: (Schmidt, Zittel, et al., 2016)

Some sources anticipate even more rapid reductions in the cost of renewable power generation. A report for Agora Energiewende (Mayer & Philipps, 2015) anticipates very substantial cost savings for solar PV by 2050. For instance, the predicted cost range for solar PV in Southern Germany falls from 7.5 to 8.5 €cent/kWh in 2014 to 2.5-4.4 €cent/kWh by 2050 (assuming capital availability at 5% interest). The difference between PV electricity at 5 €cent/kWh vs. 2.5 €cent/kWh could be profound for the business case for electrofuels, reducing the cost contribution from electricity for a 50% efficient PtL conversion process from 1,200 €/toe to 600 €/toe. Other sources are less optimistic. Narbel & Hansen (2014) anticipate median global cost of power generation in 2050 of at least 6 €cent/kWh for solar PV and 8 €cent/kWh for solar concentrating solar power (CSP), with a lower rate of 4 €cent/kWh for onshore wind. The UK Government anticipates 2030 costs of at least 5 €cent/kWh for onshore wind and 6 €cent/kWh for solar PV (in the UK).

While EU renewables costs are expected to fall to 2050, the lowest cost renewable electricity generation is likely to be for PV and CSP in regions with the highest rates of insolation. Schmidt, Zittel, et al. (2016) assert that, "PtX imports from world regions with favourable conditions for

16 Under the UK contracts for difference scheme, https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

renewable electricity production are some 20% lower in costs. Imports are thus likely, particularly with increasing PtL volumes." They identify concentrating solar electricity generation in North Africa as a promising and relatively low-cost generation technology to couple to electrofuels production, modelling a facility with 200 MWe generation capacity with thermal energy storage (allowing overnight electricity generation. By 2050, they estimate that such a facility could generate electricity for 5.5. €cent/kWh, supporting up to 6,500 hours per year of operation for an attached electrofuel facility. Mayer & Philipps (2015) again have a lower cost forecast for North African power, suggesting a range of 1.5-3.4 €cent/kWh for solar PV in Morocco (at 5% capital cost) by 2050. This research group, the Fraunhofer institute for Solar Energy Systems, considers solar PV to be much more promising on cost than CSP for at least the medium term. Another of their reports (Kost et al., 2013) expects that for high solar irradiation regions, in 2030 the levelised cost of CSP will be between 9 and 11 €cent/kWh, compared to a range from 4 to 7 €cent/kWh for solar PV technologies.

Schmidt, Weindorf, et al. (2016) identify a different low cost electricity generation example, that of the Rawson wind farm in Argentina. This facility, rated to 77.4 MW, required about $144 million of investment. At an interest rate of 4%, Schmidt, Weindorf, et al. (2016) estimated an electricity production cost of 4 €cent/kWh.

It is possible that renewable electricity costs, which have fallen impressively in the last decade, will continue to fall ahead of most analyst's expectations. One report from Saudi Arabia in October 2017[17] details a project bid to develop solar PV at a cost of only 1.52 €cent/kWh, with other bidders offering a range from 1.98 to 2.85 €cent/kWh. It is clear, however, that most analysts still anticipate a lower rate of cost reduction, and it would be unwise to base expectations of the financial viability of future electrofuel production only on the most optimistic projections and lowest cost cases.

It is beyond the scope of this paper to attempt a comprehensive and critical review of the assumptions built into the various projections of levelised 2050 renewable electricity costs. It seems reasonable to conclude that renewable power is likely to be available to electrofuels producers by 2050 at rates of up to 5 €cent/kWh. Whether the lowest production cost renewable power will really drop towards 2 € cent/kWh, as anticipated by Mayer & Philipps (2015), is much less clear.

Hydrogen from electrolysis

The first process step in electrofuel production is the electrolysis of water to produce hydrogen from electrical energy. Electrolysis can be split into low temperature technologies (alkaline and polymer electrolyte membrane or 'PEM') that have a relatively high technology readiness level, and high temperature solid oxide electrolyser cell ('SOEC') electrolysis that offers higher efficiencies, but is not yet commercialised. Table 5 shows efficiencies and predicted efficiencies for low and high temperature electrolysis from Schmidt, Zittel, et al. (2016). Part of the reason for the higher reported efficiency of electricity conversion to hydrogen for SOEC electrolysis is that as the inputs are in a high temperature (i.e. higher energy) state to start with. For drop-in electrofuel production, the exothermic nature of fuel synthesis reactions (e.g.

17 https://www.thenational.ae/business/energy/world-s-cheapest-prices-submitted-for-saudi-arabia-s-first-solar-project-1.663842

FT synthesis) allows in principle for the process heat for electrolysis to be recycled from heat produced at the fuel synthesis stage.

Table 5. Evolution of electricity consumption and efficiency for low temperature water electrolysis (Schmidt, Zittel, et al., 2016)

		Unit	2015	2020	2030	2040	2050
Low temperature	Electricity consumption	*kWh/Nm³*	5.2	4.6	4.5	4.2	4.2
		kWh/kg	58	51	50	47	47
		kWh/kWh_{LHV}	1.733	1.538	1.5	1.41	1.41
	Efficiency (LHV)		57.7%	65.0%	66.7%	70.9%	70.9%
High temperature	Electricity consumption	*kWh/Nm³*	3.4	3.4	3.3	3.3	3.3
		kWh/kg	38	38	37	37	37
		kWh/kWh_{LHV}	1.15	1.15	1.11	1.12	1.12
	Efficiency (LHV)*		87.3%	87.0%	90.0%	89.4%	89.4%

** Quoted efficiency for high temperature electrolysis considers only conversion of electricity to hydrogen, and does not take account of heat input.*

Investment costs for electrolysis capacity are significant. For low temperature electrolysis, Brynolf et al. (2017) report investment requirement of 600 - 3700 €/kWe in the short term, reducing to 300 – 1300 €/kWe in the longer term. For an electrolysis plant with 100 MWe input capacity, this means of the order of €100 million of investment. For large facilities on the 100 MWe scale, Schmidt, Zittel, et al. (2016) anticipate that by 2050 investment requirements could be as low as 250 €/kWe. High temperature electrolysis is unlikely to be available at commercial scale until 2030 or so - Brynolf et al. (2017) predict investment requirements of 400 – 1000 €/kWe.

Operational costs are generally expected to be relatively modest for electrolysis plants (annual operation and maintenance (O&M) costs of about 2% of investment for larger plants (Brynolf et al., 2017)), except for electricity costs and the cost of periodically replacing the electrolyser stack for low temperature electrolysers. Depending on utilisation rates, the electrolyser stack may need to be replaced several times during the operational lifetime of an electrofuel project, with a cost of around 50% of the initial investment requirement for the facility. Brynolf et al. (2017) identifies lifetimes of 75,000 and 62,000 operational hours for current alkaline and PEM electrolysers respectively, meaning that the stack may need to be replaced in less than ten years for a plant operating all year round. Especially in the near term, this may be a significant contribution to overall costs (up to 16% in Figure 3).

Fuel synthesis

Methanation

Once hydrogen has been produced from electrolysis, there are a number of options available for further chemical synthesis to produce fuels that are easier to store, distribute and/or use. The simplest of these is methanation, combining hydrogen with carbon dioxide to produce methane that can substitute natural gas in static and transport applications. Brynolf et al. (2017) document average reported investment requirements of 200 to 600 €/kW$_{CH4}$ for catalytic methanation, depending on plant size. They also note that pathways are being developed for biological methanation which may offer reduced investment costs.

Methanol production (and conversion to drop-in fuels)

A second option for fuel synthesis from hydrogen is methanol production. Methanol can be blended in petrol or used as a basis for further synthesis. Brynolf et al. (2017) report that the average reported cost of investment for methanol synthesis is about 50% higher than for methanation, 300 – 1000 €/kW$_{CH4}$ depending on plant size. From methanol, it is possible to undertake further chemical processing to produce drop-in transport fuels, prioritising either petrol or diesel/jet fuel. For diesel synthesis via DME and oligomerisation, Schmidt, Zittel, et al. (2016) report investment requirements of 550 – 860 €/kW$_{fuel}$, with the higher value being current and the lower a projection to 2050. For a methanol to petrol process, Brynolf et al. (2017) report total investment cost (including methanol synthesis) of 600-1700 €/kW$_{fuel}$, depending on plant size.

FT fuel synthesis

The alternative pathway for drop-in fuel production from hydrogen is the use of Fischer-Tropsch synthesis. FT technology has been develop for the production of liquid fuels from syngas derived from coal (CtL), natural gas (GtL) and biomass (BtL). With the use of the reverse water gas shift to produce carbon monoxide as a co-feed, it could also be applied to electrofuels. Brynolf et al. (2017) give average reported investment requirements of 400-1300 €/kW$_{fuel}$, depending on plant size. While the ranges for expected cost overlap, there is a general expectation in the literature that FT synthesis pathways may be more financially viable than pathways through methanol.

Cost of capturing carbon dioxide

In addition to electricity, production of synthesised electrofuels (i.e. electrofuels other than H_2) requires carbon dioxide as an input. This may be captured from industrial point sources, or could in principle be captured from the air. In the near term, the source of the CO_2 makes no difference to the climate impact, providing the CO_2 capture itself uses renewable energy. The atmosphere doesn't care whether CO_2 was sourced by temporarily sequestering it through atmospheric capture, or by delaying its emission from a point source. Table 6 provides estimates from Brynolf et al. (2017) of the cost of CO_2 from different sources.

Table 6. Estimated cost of carbon dioxide, €/tonne

CO_2 source:		Gas power plants	Coal power plants	Petroleum	Cement	Iron and steel	Ammonia	Bioethanol	Ambient capture
Short term	Low	20	30	60	70	50	10	10	n/a
	Mid	35	71	92	102	59	14	14	n/a
	High	60	170	140	150	70	20	20	n/a
Long term	Low	10	10	30	30	30	5	5	20
	Mid	24	32	52	39	42	10	10	138
	High	60	100	90	50	60	20	20	950

The most cost efficient CO_2 sources are those that are already high concentration and relatively uncontaminated, such as ammonia plants and fermentation for bioethanol. The higher costs detailed for some industrial sources reflect the cost of cleaning the CO_2 stream and getting it to the necessary concentration for fuel synthesis. Atmospheric capture technology is not yet commercially available for the required scale[18], and the cost may be significantly higher than available from point sources. As shown in Figure 3, for point sources CO_2 costs are not expected to be a large part of the cost of running an electrofuels facility. For the lowest cost CO_2 source identified in Table 6, it is estimated that the contribution to the production cost of FT electrofuel would be about 26 €/toe. For the mid-point estimate of the cost of atmospheric capture, in contrast, the carbon dioxide capture could become a more significant element of the overall fuel production cost. At 140 € per tonne of captured carbon dioxide, the contribution to the cost of FT electrofuel would be 360 €/toe. Schmidt, Weindorf, et al. (2016) calculate an even larger contribution due to the cost of atmospheric CO_2 capture – Table 4 shows a 530 €/tonne cost differential for using atmospheric CO_2 capture instead of point sources.

It is worth distinguishing between the cost of capturing CO_2, and the value set by policy for abatement of CO_2 emissions. In this section, the costs quoted reflect the installation and operation of equipment to capture CO_2 from industrial sources or from the air, and supply that CO_2 to an electrofuel facility. This is entirely separate from the social cost of carbon dioxide emissions, and the cost of carbon abatement that is set explicitly or implicitly in climate change mitigation policies such as the ETS and the RED.

18 ClimateWorks opened a demonstration ambient capture plant in Switzerland earlier in 2017, which can extract 900 tonnes of CO2 per year. With an output of 100,000 tonnes per year, an FT electrofuel plant would require 750 capture plants on this scale to feed it.

In the near term, there is no risk of running out of point sources of CO_2, as both industrial processes and fossil power generation will continue emitting large volumes of CO_2 a couple of decades yet, even in Europe. If the electrofuels industry starts to deliver a significant fraction of transport fuel at the same time as industrial decarbonisation moves forward, however, it is worth asking whether point CO_2 sources would be available in the requisite quantities in the long term, or whether atmospheric capture of CO_2 would become necessary. Von der Assen, Müller, Steingrube, Voll, & Bardow (2016) characterise current rates of CO_2 production in the EU, and cross references these volumes of production against the estimated energy intensity of CO_2 capture from each source. About 1.4 gigatonnes of CO_2 supply is identified. For comparison, producing 50% of EU aviation fuel energy in 2050 as electrojet would create demand for about 540 million tonnes of carbon dioxide. About 930 million tonnes of the documented current CO_2 supply comes from power generation, which should be eliminated in a decarbonised economy. Of the remainder, 140 million tonnes comes from iron and steel production, 160 million tonnes from cement production and 90 million tonnes from ammonia and pulp and paper production. These sources may be somewhat more persistent than fossil power generation, but should still be reduced significantly by 2050. We conclude that for a very large electrofuel industry it is likely that an increasing deployment of atmospheric CO_2 capture would become necessary after 2040.

Cost of capital

Somewhat similarly to advanced biofuel plants, electrofuels production is associated with considerable capital costs. Production costs are therefore sensitive not only to the cost of electricity and cost of running and building facilities, but to the cost of the capital required to develop a project in the first place. Brynolf et al. (2017) provide a review of assumptions made in previous economic assessments regarding interest rate paid on loans/equity investments, showing a range from 3% to 10%. These interest rates are low compared to assumptions for the interest rate on either debt or equity for advanced biofuel facilities; Peters et al. (2016) suggest interest rates between 10% and 16%, with the lower rates associated with '*n*th of a kind' plants and the higher rates associated with 'first of a kind' plants. In a review of renewable energy financing, Justice (2009) reports expected rates of return[19] for various types of equity investor, reporting that venture capital funds seek returns of at least 50%, private equity is likely to seek returns of 25% and infrastructure and pension funds are likely to seek returns of 15% (IRR basis).

Given that at the current stage of development, the regulatory framework, financial case and technological readiness for electrofuels are all (on face value) less favourable than for biofuels, it is unduly optimistic to think that capital would be available to electrofuels projects at a lower interest rate than to advanced biofuels plants. The studies that assume an interest rate below 10% will therefore tend to underestimate the real costs of facility development, at least for the short to medium term. This includes many of the studies reviewed that considered drop-in synthetic fuel production (Fu, Mabilat, Zahid, Brisse, & Gautier, 2010; König, Baucks, Dietrich, & Wörner, 2015; Schmidt, Weindorf, et al., 2016; Schmidt, Zittel, et al., 2016; Smejkal, Rodemerck, Wagner, & Baerns, 2014; Tremel, Wasserscheid, Baldauf, & Hammer, 2015). Even

19 Capital costs/minimum rates of return do not map directly to interest rates, as capital charges are quoted including debt repayment, e.g. a 12% interest rate with 10 year repayment would be equivalent to an 18% capital charge. The longer the loan repayment period, the closer the interest rate to the equivalent capital charge.

a 10% rate, the highest identified in any study, remains optimistic for private finance for first of a kind facilities.

While capital costs for the first wave of plant investments will undoubtedly be higher than these studies allow for, in the longer term, given successful demonstration of the technology at scale and stable regulatory frameworks, there is some prospect that capital costs could be reduced. Ecofys reported in 2016[20] that for onshore wind projects the weighted average cost of capital in Europe had fallen as low as 3.5% for projects in Germany, although it was still as high as 12% in other Member States. This demonstrates that if the perception of technical and regulatory risk for a given project type can be largely eliminated, capital costs can be dramatically reduced. None of the potential regulatory incentives currently on the table, however, look likely to deliver such confidence to electrofuels investors in the near term.

One possibility to reduce the effective cost of capital to developers in the near term would be government measures to support financing, for instance through grants, low-interest loans or loan guarantees. There are parallels for such measures in the EU's 'NER 300' funding programme[21] and in various U.S. programmes (Miller et al., 2013), and government funding has supported existing pilot and demonstration facilities[22]. The leverage of public support to drive investment has not been without challenges, however, and it is not clear that any existing EU funding mechanism is well suited to accelerate the deployment of electrofuels. An advisory group to the European Commission's Sustainable Transport Forum concluded that, "NER300 has failed to promote several promising technologies from the pilot/demonstration to the first-of-a-kind plants status," and that, "If the aim is to promote and support promising technologies for first-of-a-kind plants any new similar programme (e.g. NER400[23]) should be re-designed."

Discussion

It is clear that cost of production represents a significant barrier to the deployment and expansion of electrofuels technologies. The most optimistic cost projections identified in the literature are built on very aggressive assumptions about cost of electricity, cost of capital and the achievement of cost reductions over time. Even if cost estimates at the low end of the documented range could be achieved, very significant public support through implicit or explicit carbon pricing would be required to deliver competitiveness in 2050 – and proportionately more support would be needed to grow the industry between now and then.

At the heart of the cost challenge for electrofuels is the cost of electricity. Whether considering grid electricity prices, or the potential cost of production of renewable electricity from attached power plants, electrofuels will not be able to compete on price with fossil fuels, or indeed the prices expected for advanced biofuels (Peters et al., 2016), without exceedingly low electricity prices and/or substantial government policy interventions (for instance in the form of carbon pricing, cap and trade schemes or utilisation mandates).

20 https://www.ecofys.com/en/press/mapping-the-cost-of-capital-for-renewable-energy-investments-in-the-eu/

21 https://ec.europa.eu/clima/policies/lowcarbon/ner300_en

22 See e.g. https://www.ngva.eu/etogas-delivers-worlds-largest-methane-production-plant-to-audi

23 Now renamed 'the innovation fund', http://ner400.com/

The cost of electrofuel production is highly sensitive to electricity prices, and thus it is reasonable to assume that if renewable electrofuel deployment at scale happens, it will happen preferentially in regions in which electrofuel producers have access to the lowest renewable electricity prices. At the moment, considering grid electricity prices to large industrial consumers, Sweden, France, Finland, Greece and Bulgaria would be the most attractive EU States for electrofuel production. Focusing on the cost of renewable energy production rather than current grid prices, solar PV in the south of the EU looks promising – but some analysts expect onshore wind to have lower levelised costs than PV energy. Some analysts see CSP as the lowest cost long term renewable electricity supply option, and CSP in regions of high solar irradiance is certainly likely to offer the most annual operating hours for electrofuels facilities directly connected to single renewable power facilities. However, as will be discussed further below there is some prospect that offering grid balancing services by operating for a smaller fraction of the year could improve the economics of electrofuel operation, in which case there may be an advantage to siting plants on the electricity grid in the EU rather than in the North African desert. The underlying cost profile of renewable power generation will no doubt also be distorted by differentiated levels of government support for investment and electricity generation. In short, it seems difficult to pre-empt at this point in time which regions will truly have the long-term competitive advantage for electrofuel production.

Whichever locations have the advantage, it is clear that given the high sensitivity of electrofuel production costs to electricity prices a difference of a few €cents/kWh in achievable electricity costs could make a major difference to the prospects of the industry. At 3 €cent/kWh, electrofuel production has the potential to be competitive with advanced biofuel production. At 5 €cent/kWh, electrofuels will be an expensive option. It may be that one of the most important actions government can take to support the eventual development of electrofuels is to continue to invest in reducing the cost of renewable electricity generation.

The flipside of the high contribution of electricity price to the cost of electrofuel production is that, compared to advanced biofuels, the cost of electrofuel production will be less sensitive to investment costs. This means that electrofuel producers may have more flexibility in terms of operating hours and contributing to grid balancing than some commentators expect. In the section below, we further discuss the potential for electrofuels to contribute to grid balancing through demand management, or even through supplying power back to the grid.

Whichever way you look at it, production cost is a major challenge in the short to medium term, when very low electricity prices are unlikely to be available. Schmidt, Zittel, et al. (2016) argued that, "In the light of further cost reductions in renewable power generation from wind and solar, the realistic level of exploitation of [electrofuel] potentials is rather limited by the public acceptance than costs." This sentiment appears premature given the evidence currently available. While it is of course true that with an adequate level of public acceptance it would be possible to develop even very expensive climate solutions, the truth is that for the immediate future there is only a very limited prospect of electrofuels becoming deliverable for the sort of carbon dioxide prices that are currently considered acceptable for advanced biofuels, which are themselves already an order of magnitude or more above current carbon prices in the EU ETS, and similarly an order of magnitude above carbon prices anticipated in the CORSIA offsetting scheme for aviation (ICCT, 2017).

As has been mentioned several times above, part of the reason that electrofuels are of interest as a long term decarbonisation technology is that they can be used to reduce fossil fuel combustion in parts of transport where it is difficult to deliver deep decarbonisation with other technological solutions, notably in parts of heavy duty road and off-road transport where electrification is most difficult and in aviation. It is highly unlikely that adequate volumes of sustainable biofuels would be available to eliminate fossil fuel use from these modes (given expected levels of demand) and therefore electrofuels present one of the only apparent scalable solutions to reduce oil use for these vehicles. If electrofuels are understood as the 'only' option to allow the operation of these vehicles in the context of deep decarbonisation, then arguably the industries in question will need to cover the costs of electrofuels, even if they are indeed very high compared to current fuel costs.

The question of willingness to pay for electrofuels is, in the end, not a technical question but a policy question. With adequate commitment, electrofuel is a technology that could be developed, but that may not be able to compete with fossil fuel on production cost at any point in the foreseeable future. Before relying on the sector to deliver on future policy aspirations Government and industry should carefully consider the business models proposed for electrofuel production, the prospect for longer term cost reductions, how electrofuels will fit into future electricity supply and demand, and what other options are available for difficult to decarbonise modes.

Resource requirements of a growing electrofuels industry

Power

As noted above, several studies have identified electrofuels as a potentially important component of a future decarbonised economy in Europe. A large scale up of renewable electrofuel production would also, however, require a large increase in renewable electricity generation. In this chapter, we consider the power requirements of increasing use of drop-in electrofuels to meet a range of indicative volume targets, and what such additional power requirements might mean for the EU electricity grid. Given that in the medium term conversion of electricity to liquid fuels is expected to achieve only about 50% conversion efficiency[24] of electricity into liquid fuel[25], delivering a significant fraction of transport energy from power to liquids technologies would represent a large additional source of electricity demand. Indeed, as noted in the introduction for on-road applications the use of electrofuels in internal combustion engines is likely to require about 5 times more total electricity generation than would be required to move the same distance with a battery electric vehicle, when combining the electrofuel production efficiency with the difference in powertrain efficiencies. Delivering transport decarbonisation through electrofuel production is therefore fundamentally more power intensive than delivering it through vehicle electrification.

The European Commission's Energy Roadmap 2050 (European Commission, 2011) lays out scenarios[26] for decarbonisation of the EU energy supply that are designed to be consistent with reducing 2050 EU greenhouse gas emissions by 80-95% compared to 1990 levels. The Roadmap includes five scenarios: high energy efficiency; diversified supply technologies; high renewable energy sources; delayed CCS; and low nuclear. None of these scenarios include significant demand for electrofuels, but they do include increased use of electric vehicles. In this section, we use the average energy demand values across these scenarios as a basis for identifying the potential electricity demand that would be associated with growth in drop-in electrofuel production to meet a given fraction of transport energy demand.

In the Roadmap's decarbonisation scenarios, total European transport energy demand reduces from about 4,300 TWh in 2020 to about 2,700 TWh in 2050, including aviation energy demand[27] in 2050 of about 660 TWh (reduced from 720 TWh in 2020). This compares to total electricity generation in 2015 of 3,600 TWh, and to total predicted 2050 non-thermal renewable electricity generation in those scenarios ranging from 2,300 to 3,700 TWh.

To provide a sense of the scale of the challenge of achieving a ramp up of electrofuel fuel

24 Assuming SOEC electrolysis and mid-range assumptions on individual process efficiencies.

25 With the commercialisation of SOEC electrolysis, and further improvements in FT synthesis or other synthesis technologies, this could be improved towards 60% over time.

26 The Roadmap also includes a 'reference' scenario in which no additional policy measures are taken, and a 'current policies' scenario in which only already agreed policies are implemented. The results from these scenarios are not used in this section.

27 Including both domestic and international flights.

production, Table 7 shows the required additional renewable electricity generation that would be required in 2050 to meet four levels of aspiration for electrofuel supply (assuming electrofuel facilities are supplied by fully renewable electricity generation in Europe). The four cases considered are:

1. 10% of total transport energy demand;
2. 50% of total transport energy demand;
3. 50% of truck energy demand;
4. 50% of aviation energy demand.

In the case of supplying 50% of truck energy as electrodiesel and 50% of aviation energy as electrojet, the modelling assumes a fuel selectivity of 75% for the FT synthesis process - i.e. that 75% of the output fuel is diesel/jet, and that there is an additional 25% output as naphtha and other molecules. This means that total energy demand in these scenarios is a third higher than the energy needed to supply fuel only for the mode in question. The absolute electricity demand for each of these levels of electrofuel production is then compared for context to current total gross EU electricity generation, including fossil, renewable and nuclear power[28].

Table 7. Additional non-thermal renewable electricity generation required in 2050 to deliver a given amount of transport energy, and compared to current gross EU electricity generation

	10% transport energy	50% transport energy	50% trucks energy	50% aviation energy
Required electricity (TWh)	540	2,720	1,310	880
Fraction of current gross EU electricity consumption	15%	75%	36%	24%

To deliver 10% of all transport energy across all modes from drop-in electrofuel would necessitate an additional 540 TWh of renewable electricity generation, equivalent to 15% of total current EU electricity generation. Delivering 50% of transport energy across all modes through drop-in electrofuel would require 2,720 TWh of additional renewable electricity generation, equivalent to 75% of current total EU power generation.

Given that much interest in electrofuels is driven by the desire to provide low carbon fuels to modes that are harder to electrify, two single-mode scenarios are also considered. To meet 50% of 2050 EU aviation energy demand with electrojet would take 880 TWh of additional renewable electricity generation, equivalent to 24% of the current EU electricity supply. Delivering 50% of truck energy would require 1,310 TWh of renewable electricity, equivalent to 36% of current EU electricity supply.

The decarbonisation scenarios in the 2050 Roadmap already imply considerable ambition and investment to deliver the additional renewable electricity capacity required to decarbonise

28 Based on the 2015 electricity generation identified by European Commission (2011).

the electricity supply for homes and industry, and for a growing fleet of electric vehicles. The large capacity additions required to meet a large fraction of transport energy supply, even for a single mode, would therefore be, at best, extremely challenging to deliver.

Previous reports similarly find that delivering a large fraction of transport energy from electrofuels would require massive additional renewable electricity generation. Schmidt, Zittel, et al. (2016) consider cases in which EU demand for electricity for transportation (including electrofuel and electric vehicles) reaches up to 13,000 TWh. This would result in total EU electricity demand 3 to 4.5 times higher than current total EU electricity generation. This would be a profound increase in the level of ambition for the expansion of the renewable power sector. Similarly, Bünger et al. (2014) find that a scenario in which power to gas or power to hydrogen fuels met a large fraction of German transport energy demand "would be associated with an electricity demand on the same order of magnitude as all other sectors combined (industry, private households, commerce, trade and service sectors)." This study comments that such an electricity demand increase would require, "enormous planning, economic and infrastructure efforts. It is therefore vital to explore all available options for the reduction of energy demand and increase of vehicle efficiencies."

Land

As will be discussed in the environmental impacts section below, electricity generation electrofuel production is considerably more land efficient than the agriculture required for biofuel production. The land requirement for solar or wind farms to supply renewable electricity for a large electrofuels industry could still be considerable though. Assuming that electrofuel production using EU solar electricity can deliver at least 500 GJ per hectare per year (Bracker, 2017; Schmidt, Weindorf, et al., 2016), the maximum land requirements for the production scenarios discussed in the previous section are shown in Table 8.

Table 8. Maximum land requirements for renewable electricity for electrofuel production scenarios

Scenario:	10% transport energy	50% transport energy	50% trucks energy	50% aviation energy
Land requirement at 500 GJ per hectare per year (million hectares)	5	24	12	8

For the case of delivering 50% of aviation energy in 2050, this is equivalent to the entire area of the Czech Republic devoted to wind farms or solar PV installations.

This is a major commitment, but is comparable to the 6.1 Mha area in the EU that is currently devoted to bioenergy cropping at a reported areal yield of 121 GJ/ha[29]. Supplying 50% of aviation energy from biofuels at those areal yields would require 33 Mha. On the other side, delivering the same amount of useful transport energy through electric vehicles would require

29 The European Commission estimates 6.1 million hectares were devoted to bioenergy crops in 2011, producing 17,600 ktoe of renewable energy from primary biomass http://ec.europa.eu/eurostat/statistics-explained/index.php/Agri-environmental_indicator_-_renewable_energy_production

much less land. For instance, given the factor five difference discussed above in overall efficiency of use of electrical energy between electric vehicles and drop-in electrofuels, supplying 50% of EU truck energy through direct supply of electric power would require only about 2.4 Mha, while doing so through electrofuels would take 12 Mha, and doing so with biofuels would take 50 Mha. While significant, the areas required to supply the fractions of transport energy detailed in Table 8 are still smaller by orders of magnitude than areas that are identified as 'available' for bioenergy production by some studies (see e.g. Searle & Malins, 2015).

Investment and operating costs

The scale of electrofuel deployment that would be necessary to meet a significant fraction of EU transport fuel demand would not only challenge the capacity of renewable power generation to keep up, but would also require a very significant ongoing level of investment. Based on investment costs for currently available technology given by Brynolf et al. (2017), a plant capable of 100 million litres per year of output electrodiesel production (if operating 8000 hours a year) using PEM electrolysis and FT diesel synthesis could require about €900 million of investment. By 2030, this could have fallen to €340 million. For a more efficient facility using SOEC electrolysis, this investment cost would fall below €300 million. There are significant uncertainties around all these values. The 2030 investment costs are high compared to the *n*th of a kind investment costs expected for cellulosic ethanol by Peters et al. (2016), about €140 million per 100 million litres capacity, but on the same scale as costs estimated for an FT BtL facility (about €370 million per 100 million litres of capacity). To deliver half of EU aviation fuel in 2050 would require about 600 facilities of this scale, implying a total required investment of the order of €160-325 billion, depending on the rate of investment cost reduction.

Schmidt, Zittel, et al. (2016) consider the case of a wholly renewable EU transport energy supply in 2050, with a large share of EU fuel coming via PtL technologies. Their scenarios would require significantly more electrofuel production than required for any of the scenarios presented in this report in Table 7. For their high-electrofuel scenario, between €2 and 3 trillion of cumulative investment would be required in cumulative investment in electrofuel plants, plus between €5 and 6.5 trillion of investment in additional renewable power generation. For an alternative scenario presented by Schmidt, Zittel, et al. (2016) with greater use of electric vehicles, the required investment in electrofuels plants would be reduced to €1.5 to 2 trillion, with €3.5 to 4 trillion of investment in additional renewable power. These investments would average on the order of 1-2% of the annual GDP of the EU over 35 years.

These investments are clearly enormous, but these very ambitious scenarios for delivering electrofuels are unlikely to be achieved in practise. Based on these investment numbers it is possible to make an alternative estimate of the potential investments required to deliver the more modest electrofuel scenarios presented in Table 7 of this report. The scenario that would require €3 trillion of cumulative investment in electrofuel facilities would deliver 2050 drop-in electrofuel production of about 4,300 TWh per annum, at an average investment of €670 million per TWh, with renewable power capacity increased at an investment cost of €510 million per TWh. At this investment rate, delivering 50% of EU aviation fuel would require €290 billion of cumulative investment in electrofuel facilities, which is within the range suggested above based on Brynolf et al. (2017), plus another €450 billion of renewable power investment. Delivering 50% of truck energy from electrofuels would require investments of €440 billion in electrofuel facilities, and of €670 billion in renewable power.

A gradual expansion of the electrofuels industry in order to support technology development and gradual cost reductions would also imply a considerable cost burden on either taxpayers, industry or fuel consumers (or some combination of all of these). Returning to the case of delivering 50% of EU aviation fuel from renewable electrofuels by 2050, we have modelled a very simple case in which production grows linearly to 600 million litres per year by 2025 and then exponentially to 2050, while production costs reduce exponentially from 3000 €/toe to 1500 €/toe, which is consistent with the lower end of most cost expectations. This would involve an additional €200 billion of cumulative additional fuel costs as compared to the continued use of fossil jet fuel at 500 €/tonne[30]. For this simple comparison we have assumed a flat price for fossil jet fuel. Commentators can be found to predict both increases and reduction in carbon-unadjusted petroleum fuel prices over this period – clearly dramatic changes in oil price would affect these illustrative cost estimates. By 2050, under these simple assumptions, the aviation industry in the EU would spend twice as much overall on aviation fuel as it would in the absence of regulations to force the use of electrofuels. According to IATA, fuel costs represent about 20% of operating expenses for the global aviation industry[31]. Moving to 50% electrofuel by 2050 might therefore be expected to add roughly 20% to the cost of flights by 2050.

30 See http://www.iata.org/publications/economics/fuel-monitor/Pages/price-analysis.aspx

31 https://www.iata.org/pressroom/facts_figures/fact_sheets/Documents/fact-sheet-fuel.pdf

Electrofuels as a grid balancing tool

In a decarbonised future, it is generally anticipated that European electricity generation will be increasingly dependent on renewable technologies such as wind and solar power that experience a high level of supply intermittency compared to traditional power generation technologies (fossil fuel combustion and nuclear fission). There is therefore considerable interest in identifying technologies and policy strategies that could be used to balance out intermittent energy supply through energy storage and demand management (Hart, Bertuccioli, & Hansen, 2016). Options for energy storage include pumped hydro, battery storage of electricity, compressed air storage, flywheels and electrofuel production.

In principle, electrofuel production has the appeal of offering elements of both demand management and energy storage (assuming that the electrofuel facility and any renewable energy facility connected to it are also connected to the grid). An electrofuel production facility could be set up to produce and store excess hydrogen during periods of high supply (and potentially low price) of renewable electricity. During periods of low availability of renewable electricity, the facility could cease hydrogen production (potentially continuing to operate fuel synthesis using stored hydrogen), and even potentially feed stored hydrogen into fuel cells and output electricity back to the grid. Alternatively, synthesised fuels could be stored at lower cost than hydrogen and potentially combusted for electricity later, although this would introduce more energy losses to the system than in the case of hydrogen storage.

While there is no question that it is technically possible to use electrofuel production as a grid balancing tool, the more difficult question is whether it is likely to be economically viable to do so (or, to put it the other way round, what the cost/benefit of doing so would be to electrofuels producers). In general, it is economically rational to run any expensive capital intensive industrial facility for as much of the time as possible in order to maximise production, and therefore revenues. On the other hand, as discussed above electricity costs are a major component of the costs of electrofuels production. If spot electricity prices show a high level of variation between periods of low supply and high supply of renewable energy, then it may be beneficial to electrofuels producers to cease production during periods of high electricity cost, or even to sell electricity back to the grid at these times. This assumes that electricity suppliers offer variable electricity pricing to industrial customers, which may currently be limited by regulation (MJ Bradley, 2013).

The simplest way for electrofuels to contribute to grid balancing would be to reduce or cease electrofuel production when renewable electricity supply is limited – or, to put it another way, to run electrofuel production only when there is excess renewable electricity available in the system. Bracker (2017) argues that, "Production plants for synthetic fuels will usually be operated 24 hours per day ("baseload"), as the chemical processes are difficult to interrupt and the high investments in the plants require a maximum usage of the available production capacity." However, given the large contribution of electricity costs to overall costs, larger than the investment cost in most models, this may be an over-simplification of the situation.

As one example, Brynolf et al. (2017) consider a relatively extreme case of demand management through electrofuel production, in which the capacity factor[32] of an electrofuel facility is reduced from 80% to 20%, but the presumed price of electricity is reduced from 5

32 This is the fraction of the year for which the plant is operating.

€cents per MWh to nothing. For the base case, even with zero electricity cost, operating at reduced capacity factor makes the facility less economically viable, increasing estimated production costs by 60% for a small facility at current estimated costs, and by 26% for a medium scale 2030 facility. This result is, however, sensitive to assumptions about investment costs. For low-end assumptions about required investment, the grid balancing model delivers 27% *lower* costs for a 2015 facility, and 35% lower costs for a 2030 facility. This is suggestive that for at least some scenarios there may be opportunities to deliver benefits through providing some sort of grid balancing service.

A more active way to use electrofuel production as a grid balancing tool would be to treat electrofuels as energy storage, and to export energy (instead or as well as electrofuels) during periods of low renewable electricity supply. The economic viability of this type of energy storage is strongly influenced by the conversion efficiencies of electricity to electrofuel, and then electricity generation efficiency. The most energy efficient option for electrofuels as energy storage would be to store excess hydrogen for use in fuel cells during periods of low renewable electricity availability. For a low temperature electrolysis efficiency of 66% (Brynolf et al., 2017) and a fuel cell electricity generation efficiency of 60% (US Department of Energy, 2006), electricity would need to be sold back to the grid at an absolute minimum of 250% of the purchase price to make this model work (in practice, given the cost of hydrogen storage and of the fuel cells, the price for sale back to the grid would need to be even more than this). It is unclear whether grid balancing services will be valuable enough to support this type of price differential. As one indicator of potential electricity price variation, we have considered price variability statistics for the German/Austrian day-ahead wholesale electricity market (Wozabal, Graf, & Hirschmann, 2016). Assuming normally distributed prices, in 2013 the average price of electricity for the 20% of the time when prices are highest was about 80% higher than the average price for the other 80% of the time. This level of price variability would likely not be adequate to support power re-supply to the grid – however, with twice the level of price variability, the average price for the most expensive 20% of the time would be 3 times the average price for the rest of the year. With that type of price differential, a model in which electrolysis is curtailed for 20% of the time, during which fuel cells were used to supply electricity back to the grid, may be worth at least assessing in more detail. The actual level of price variability due to intermittent renewable supply in the future grid will of course depend on how effectively other grid balancing measures are introduced.

For 80% efficiency for the electrolysis and fuel cell, potentially achievable by 2050, the picture is more promising, with a potential system efficiency of 64%, which would require an electricity price to sell electricity that was at least 160% of the price to buy. Even so, solutions such as battery storage will offer a significantly lower energy loss through the system (IRENA, 2015 report effiiciencies around 80%), potentially enabling them to provide much lower-cost balancing services.

Scenario model for financial impact of demand curtailment

In order to allow additional investigation of sensitivity of electrofuel production costs to key parameters, a simplified cost model has been developed for FT electrodiesel/electrojet, using data primarily from Brynolf et al. (2017). This model is used to produce the results in this section.

Wozabal et al. (2016) provide descriptive statistics of daily electricity price variation for day-ahead electricity futures for Germany/Austria from 2007 to 2013. For 2013, the average price was reported as 0.45 €cents per kWh, with a standard deviation of 0.15 €cents. Using these price variation data and the cost model we have investigated the potential to improve the business model for electrodiesel production by shutting down electrolysis during periods of low electricity supply, and high wholesale price. For the analysis, we have modelled a medium-term technology configuration, using PEM electrolysis and FT fuel synthesis, with 100 MWe electricity consumption, based on mid-range parameters from Brynolf et al. (2017). The conversion efficiency of electricity to syndiesel is 41%. The baseline utilisation rate for both electrolysis and FT facility is 8000 hours per year (91% capacity factor). CO_2 is air captured, assuming 138 € per tonne of CO_2 (Brynolf et al., 2017), and the cost of capital is 12%. The baseline grid electricity price is 8 €cent/kWh. The resulting baseline modelled cost of fuel production is 3,600 €/toe, as detailed in Figure 8.[33]

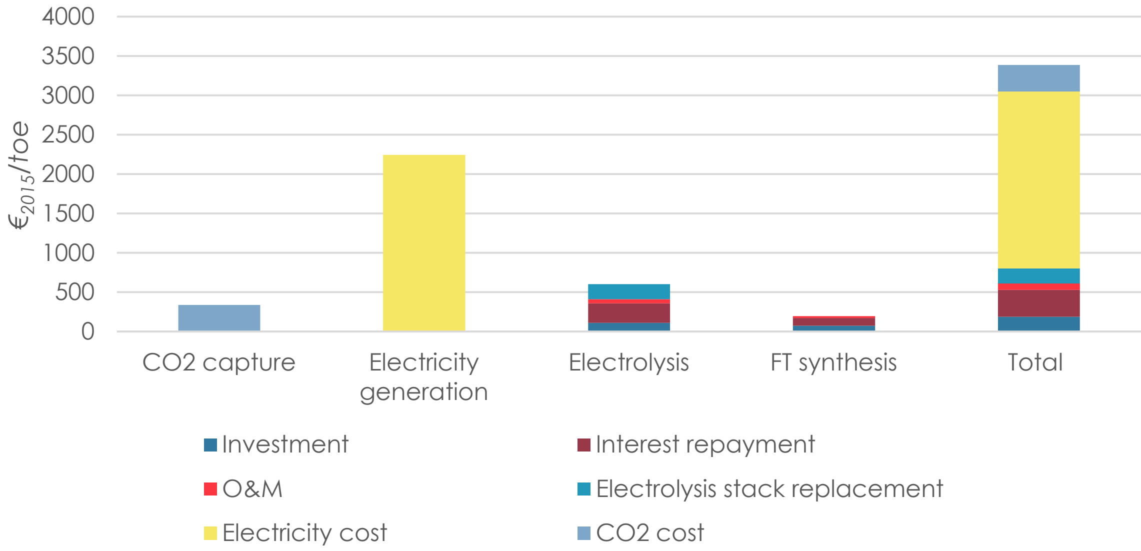

Figure 8. Cost breakdown for modelled 2035 electrodiesel production pathway34

For the modelling, it is assumed that wholesale price constitutes two thirds of the average grid electricity price to large industrial consumers[35], and that only the wholesale price element is variable over time. We assume that the electrofuel facility is exposed to these variations in wholesale electricity price, and is able to start and stop production relatively quickly without

33 The primary purpose of the modelling here is to investigate the financial impact of limiting production to assist grid balancing, so the reader is encouraged to focus on the difference between cases rather than the result for absolute cost of this modelled technology scenario.

34 The total estimated fuel production cost here is in fact higher than the 'base' case for 2015 from (Brynolf et al., 2017). This is largely due to a higher presumed average electricity price, but also due to a higher cost of capital and the use of atmospheric carbon capture.

35 The European Commission (European Commission, 2016c) found that for medium sized industrial electricity consumers (5,000-20,000 MWh per annum) wholesale price averaged 60% of consumer price in the period 2008-2015.

excessive additional costs. Wholesale prices are assumed normally distributed about the mean. As in the day-ahead market in Germany, price are allowed to go negative in the calculation. Two price variability cases are modelled, the first with the same fractional standard deviation as reported for the day-ahead market 2013 by Wozabal et al. (2016), the second with twice that standard deviation. For this simplified modelling, only the utilisation of the electrolysis facility is adjusted.[36]

Table 9 shows the average price experienced by an electrofuel facility that curtails electrolysis for a given % of the time when electricity prices are highest, given the level of price variability described in the German day-ahead market for 2013. For instance, shutting production for 20% of the time would reduce the average electricity price from 8 to 7 €cent/kWh. Running only for the 20% of the time with lowest prices would reduce average electricity price from 8 to 5 €cent/kWh. The potential savings from part-time production are sensitive to the level of variability around the average price. Given twice the variability, the average price paid for electricity could be reduced to 2 €cent/kWh by 80% curtailment of electrolysis.

Table 9. Average price of electricity to electrofuel facility (€cent/kWh), given curtailment of electrolysis for the X% of the time when wholesale electricity price is highest

	Average electricity price paid by electrofuel producer (€cent/kWh) given…					
	Full utilisation	20% curtailed	40% curtailed	50% curtailed	60% curtailed	80% curtailed
Price variability of 2013 day-ahead German electricity market	0.080	0.072	0.066	0.063	0.059	0.050
Double price variability	0.080	0.065	0.052	0.045	0.038	0.019

Figure 9 and Figure 10 show the modelled outcomes for curtailing electrolysis during high prices. For the case with the same variability of electricity price as documented for the 2013 German day-ahead market (Figure 9), there is a marginal production cost reduction achieved by curtailing electrolysis for 40% of the time. Any further reductions in production rate increase costs again. For the case with increased price variability, the optimum case is to operate only 50% of the time (Figure 10).

36 The FT plant could be made smaller with the addition of extra hydrogen storage, run for less time, or fed with additional hydrogen from other locations – we have not attempted to model these possibilities here.

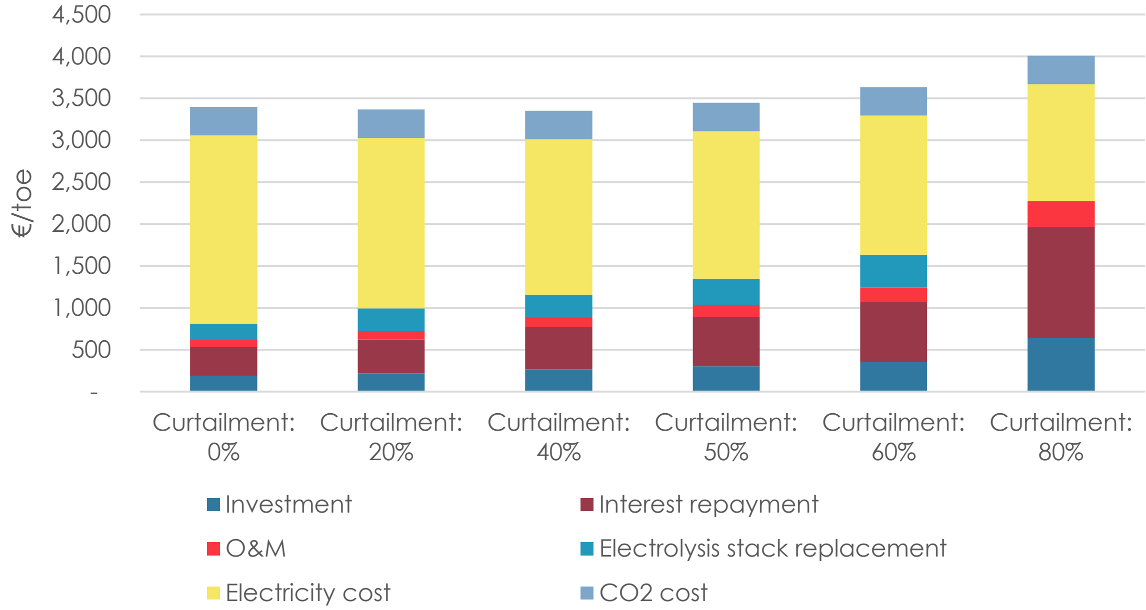

Figure 9. Modelled electrodiesel production cost given wholesale electricity price variability documented for 2013 German day-ahead market

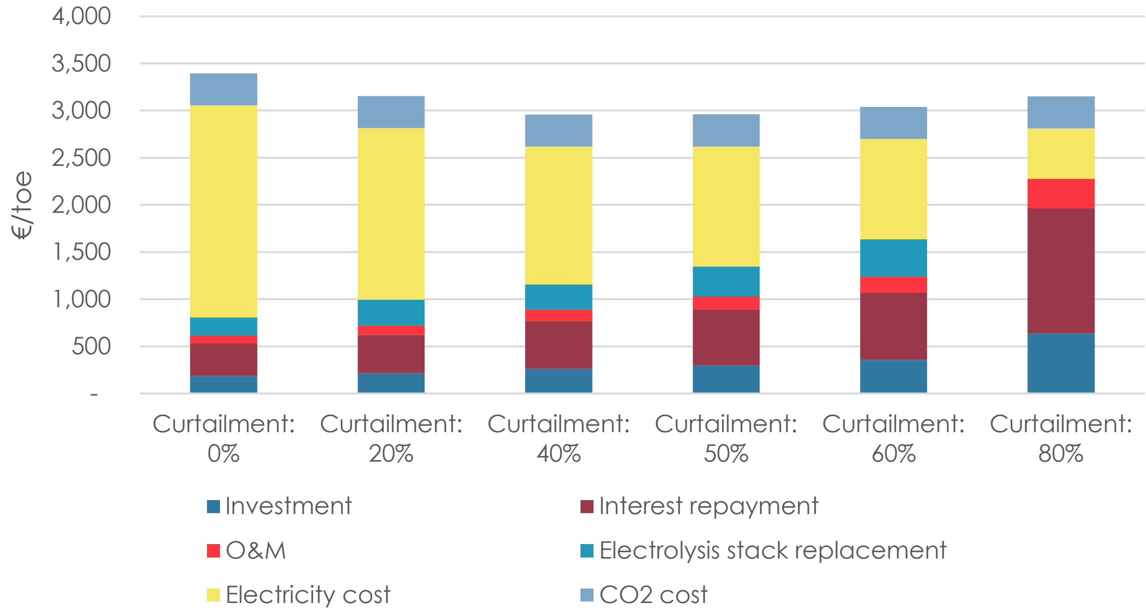

Figure 10. Modelled electrodiesel production cost given double the wholesale electricity price variability documented for 2013 German day-ahead market

A note of caution should be sounded regarding the interpretation of this modelling. The model is highly simplified, and does not consider the interaction between rate of electrolysis utilisation, rate of syndiesel synthesis and required H_2 storage. Given that the cost outcomes are quite similar in all cases, a modest change in assumptions could change the direction of the results. For instance, with a lower baseline assumption on cost of grid electricity (5 €cent/kWh) the benefits of curtailing electrolysis disappear, given the current level of price variability. Disclaimers aside, these results do suggest that it at least might be financially beneficial to operate electrofuel production in a way that is sensitive to electricity supply intermittency, assuming that intermittency is reflected in hourly electricity prices. Operating in this fashion could reduce the burden to the electricity supply more generally of an expanded electrofuels industry.

Discussion

As the fraction of renewable electricity generation in the EU electricity supply increases, mechanisms will be required to handle intermittency in power generation. Depending on how its use of electricity is structured, a growing electrofuels industry could make this problem worse, or could play a role in handling it.

As with any high capital expenditure industrial facility, there will be a clear advantage to running an electrofuel facility at full capacity with as few shut-downs as possible. This model of operation would imply a constant power demand, and therefore would hinder rather than help electricity suppliers to deal with variable supply. Several commentators assume that this mode of operation will be the most profitable for electrofuel producers, in which case the electrofuels industry would have to be understood as a 'problem' from the point of view of grid balancing.

This picture would change if electrofuel producers were able to access electricity more cheaply during periods of high supply, and conversely were forced to pay more during periods of low supply. Cost modelling presented above shows that for observed levels of wholesale electricity price variability, it may be economically rational for electrofuel facilities to limit production during periods of highest electricity prices. In that case, provided they are exposed to variable electricity prices, electrofuel producers could be one of a number of industrial electricity consumers able to contribute to grid balancing through demand management.

It is less clear whether electrofuel producers will be competitive in an active energy storage capacity. In the active-storage model, instead of simply reducing hydrogen production at points of low renewable electricity supply, electrofuel producers could feed stored hydrogen into stationary fuel cells and supply electricity back to the grid. This is a more complicated business model, requiring additional investment, and may be limited by the lower efficiency of conversion of electricity to hydrogen and back as compared to storage of electricity in batteries. It is beyond the scope of this report to undertake detailed comparison of this active storage model against other electricity storage approaches, but we suspect that such a model could only work economically in the event of large increases in grid electricity price variability compared to the current paradigm. Certainly though it is a question that merits further assessment.

Environmental impacts of an expansion of electrofuel technologies

Any expansion of electrofuel production and use in Europe would be predicated on delivering lower environmental impact than is associated with the use of fossil fuels, and indeed some biofuels. It is therefore important to consider the potential environmental impacts of an expansion of electrofuel production, both on greenhouse gas emissions and on other environmental indicators.

Carbon sources

One of the more controversial questions in the current discourse about renewable electrofuels is the source of carbon dioxide used for fuel synthesis. Potential carbon dioxide sources can be grouped into three categories:

1. Carbon dioxide captured from the atmosphere;
2. Carbon dioxide captured from point source industrial processes that emit biogenic carbon;
3. Carbon dioxide captured from point source industrial processes that emit fossil carbon.

The prevailing convention in lifecycle analysis for electrofuels is to treat the combustion of the fuel as carbon neutral, on the basis that the carbon atoms were either a) extracted from the atmosphere or b) extracted from a waste gas stream that would otherwise have been emitted to the atmosphere. This treatment has parallels in emissions reduction accounting (for instance crediting projects that capture excess methane and use it for energy instead of flaring it (Malins, Searle, Baral, et al., 2014) and in biofuel accounting, where the emissions from fuel combustion are conventionally ignored on the basis that the carbon atoms emitted were recently absorbed from the atmosphere. This treatment is appropriate provided the counter-factual (the assumption that the CO_2 would otherwise have been emitted) remains accurate. This will generally be true at present, but in future as decarbonisation moves forward and technologies such as carbon capture and storage become more widespread, it may be appropriate to reconsider what the appropriate counter-factual is.

Different carbon capture systems will have different associated energy intensity. In general, more concentrated CO_2 streams require less energy to capture and concentrate. Von der Assen et al. (2016) provides a characterisation of the energy intensity of different CO_2 capture options, if undertaken using average EU electricity. Average reported values for a variety of different CO_2 sources are detailed in Table 10.

Table 10. Average energy use estimates for different CO2 capture options

Source	Concentration	Electricity demand ($MJ/kgCO_2e$)	Heat demand ($MJ/kgCO_2e$)
Air capture	0.04%	1.29	4.19
Gas power plant	3-4%	1.6	0
Coal power plant	12-15%	1.22	0
Kraft integrated pulp and paper mill	7-20%	0.04	1.57
Iron and steel	17-35%	0.87	0.95
Cement	14-33%	0.09	3.35
Ammonia	~100%	0.4	0.01

Source: (von der Assen et al., 2016)

Atmospheric capture of CO_2 is more energy intensive than the capture of CO_2 from concentrated industrial sources, and therefore it is currently more efficient to use industrial CO_2 sources as feedstock for electrofuels. Some analysts and commentators, however, have argued that carbon dioxide from fossil sources should be treated differently in lifecycle analysis and regulation to carbon dioxide from biogenic sources or from atmospheric capture. Bracker (2017) argues that, "a fossil carbon source is by nature not renewable and therefore synthetic fuel production that uses fossil carbon does not adhere to the concept of a circular economy," and that, "in the medium- to long-run on the pathway towards a decarbonised economy, fossil carbon sources will become scarce." On this basis, it is argued that, "Sustainability requirements for carbon-based synthetic fuels should therefore require the use of atmospheric CO_2 either via direct air capture or via biogenetic sources." Similarly, Naims, Olfe-Kräutlein, Lorente Lafuente, & Bruhn (2015) assert that, "using CO_2 generated mainly from fossil sources as a feedstock in industrial processes is not consistent with existing policy definitions of 'renewable', such as those established in the promotion of renewable energies," and Fasihi et al. (2016) state that, "To have a sustainable energy system with carbon neutral products, CO_2 needs to be obtained from a sustainable CO_2 source."

While it is true that in a highly decarbonised economy the availability of CO_2 from point sources will be dramatically reduced, at the current time it seems premature to be concerned about the provenance of CO_2 utilised for electrofuel production. As discussed above in the section on the cost of capturing carbon dioxide, based on the CO_2 availability estimates from von der Assen, Müller, Steingrube, Voll, & Bardow (2016) even a very large electrofuel industry would not start to exhaust unabated point CO_2 sources for some time to come. Indeed, Naims et al. (2015) also observe that:

> *"Even if all coal and gas-fired power plants were decommissioned, the total CO_2 emissions from other sources (e.g. the cement, iron and steel industry or refineries) would still be large enough to cover the demand for CO_2, according to optimistic long-term scenarios for the development of CCU."*

In short, there is no immediate danger of Europe running out of carbon dioxide emissions to feed into electrofuels plants. As the energy transition moves forward, fossil CO_2 sources will begin to disappear, and in some case electrofuels facilities may be forced to look for new CO_2 sources, such as atmospheric capture. There may also at some point be a need for regulatory revisions to encourage a transition from the use of point CO_2 sources from fossil fuel combustion to alternative sources such as direct air capture.

In the near term, there is no clear environmental benefit from a requirement to use only non-fossil CO_2 sources. Indeed, such a requirement would impose unnecessary costs on electrofuels production, increase overall energy consumption by the electrofuel industry for no environmental benefit, and tend to eliminate fossil fuel burning companies as potential project financers, thus creating an unnecessary barrier to growth in an industry already facing an uphill struggle to commercialise. In the existing Renewable Energy Directive (RED), the emphasis is correctly on the renewability of the energy supply, not on the source of carbon dioxide as a process feedstock. We see no reason to change this emphasis in the development of the revised directive, RED II, for application in the period 2020-2030.

Double counting emissions reductions

While we see no compelling case to regulate against the use of CO_2 from fossil fuel combustion in electrofuel production, there is a legitimate concern among some stakeholders that the emission savings delivered from using electrofuels instead of conventional fossil fuels should not be counted twice. By capturing and recycling CO_2 from industrial facilities, it is possible to produce a transport fuel that can be combusted without adding to the net atmospheric CO_2 loading. This does not prevent the emissions of the CO_2 from the original combustion. Given the extra value placed by European policy makers on delivering emissions reductions in the transport sector, it is reasonable to count electrofuels towards compliance with targets for renewable energy in transport. Certainly, without the enhanced value of decarbonisation in the transport sector, it is difficult to see an electrofuels industry developing. Greenhouse gas emissions reductions rewarded in the transport sector should not then be counted a second time by crediting the industrial facilities at which the carbon was captured, such as by giving a second credit under the ETS.

If captured emissions were credited under ETS and then also allowed to be counted as carbon neutral under renewable energy legislation for transport, this would result in inconsistent carbon accounting, and in over-incentivisation of electrofuels compared to other decarbonisation options. Indeed, Helseth, Whiriskey, & Serdoner (2017) argue that with this type of double counting,

> *"A perverse incentive could develop; instead of being incentivised by CO_2 pricing to actually reduce emissions per tonne of product, EU industries get an incentive to maximise CO_2 for subsidised synthetic fossil fuels production."*

It is hardly realistic to believe that the value of CO_2 to electrofuels production would be adequate to incentivise active increases in CO_2 production from industrial facilities, but it is correct to note that if carbon capture for electrofuels production results in credits under the ETS, then the incentive to reduce CO_2 emissions instead of capturing them would disappear, with deleterious consequences for long term decarbonisation plans.

In contrast, if industrial CO_2 emitters are still required to pay the carbon price of their emissions under the ETS, options for CO_2 utilisation, sequestration and reduction can compete on an even footing, resulting in the delivery of the most cost-effective climate solutions.

Lifecycle analysis of greenhouse gas emissions

The greenhouse gas emissions associated with electrofuels production are driven almost entirely by the greenhouse gas emissions intensity of the electricity used for the electrolysis stage, and to a lesser extent for the fuel synthesis. Given the use of renewable electricity, there is agreement in the lifecycle literature that electrofuels can have a very low carbon intensity. The Joint Research Centre's Well to Wheels study (Edwards et al., 2013), for instance, calculates a lifecycle carbon intensity of 1.3 gCO_2e/MJ for a pathway to electrodiesel via methanol. This is 99% lower than the carbon intensity of fossil diesel consumed in the European Union, 94 gCO_2e/MJ (European Commission, 2016b). The JRC analysis assumes that renewable electricity is used for all process power, not only for electrolysis, and that process heat from fuel synthesis is utilised for processes that require heat.

This result only holds for the use of renewable electricity though. Because of the efficiency losses in the fuel synthesis process, for non-renewable energy the greenhouse gas intensity per unit of delivered energy for electrofuels is proportionately higher than for the electricity source. Electrodiesel from coal, based on the JRC data and efficiency assumptions[37], would have a carbon intensity of nearly 600 gCO_2e/MJ, 6 times worse than fossil diesel. With the current EU electricity mix, the greenhouse gas intensity would be 307 gCO_2e/MJ, three times higher than a fossil fuel comparator. The carbon intensity of electrodiesel given various electricity sources is shown in Figure 11. In all cases except zero-carbon[38] renewable power electrodiesel has a higher carbon intensity than fossil diesel. Even for efficient natural gas power with carbon capture and storage, and for example pathways for biomass power[39], the resulting electrofuels would have higher greenhouse gas intensity than the fossil fuel comparator. It is therefore of the utmost importance for the environmental performance of electrofuels that the electricity for electrodiesel should be supplied solely from the lowest carbon renewable sources.

37 JRC assumes that 2.45 MJ of electricity input is required for the overall process for every 1 MJ of fuel delivered.

38 By 'zero-carbon' renewables, we refer to renewable power that is not associated with any operational carbon emissions, such as wind and solar power. Emissions associated with facility construction are not counted towards the lifecycle by convention, but are relatively small over the lifetime of one of these facilities.

39 Greenhouse gas intensity of biomass electricity taken from European Commission (2016b). Other electricity greenhouse gas intensity values taken from (Edwards et al., 2013).

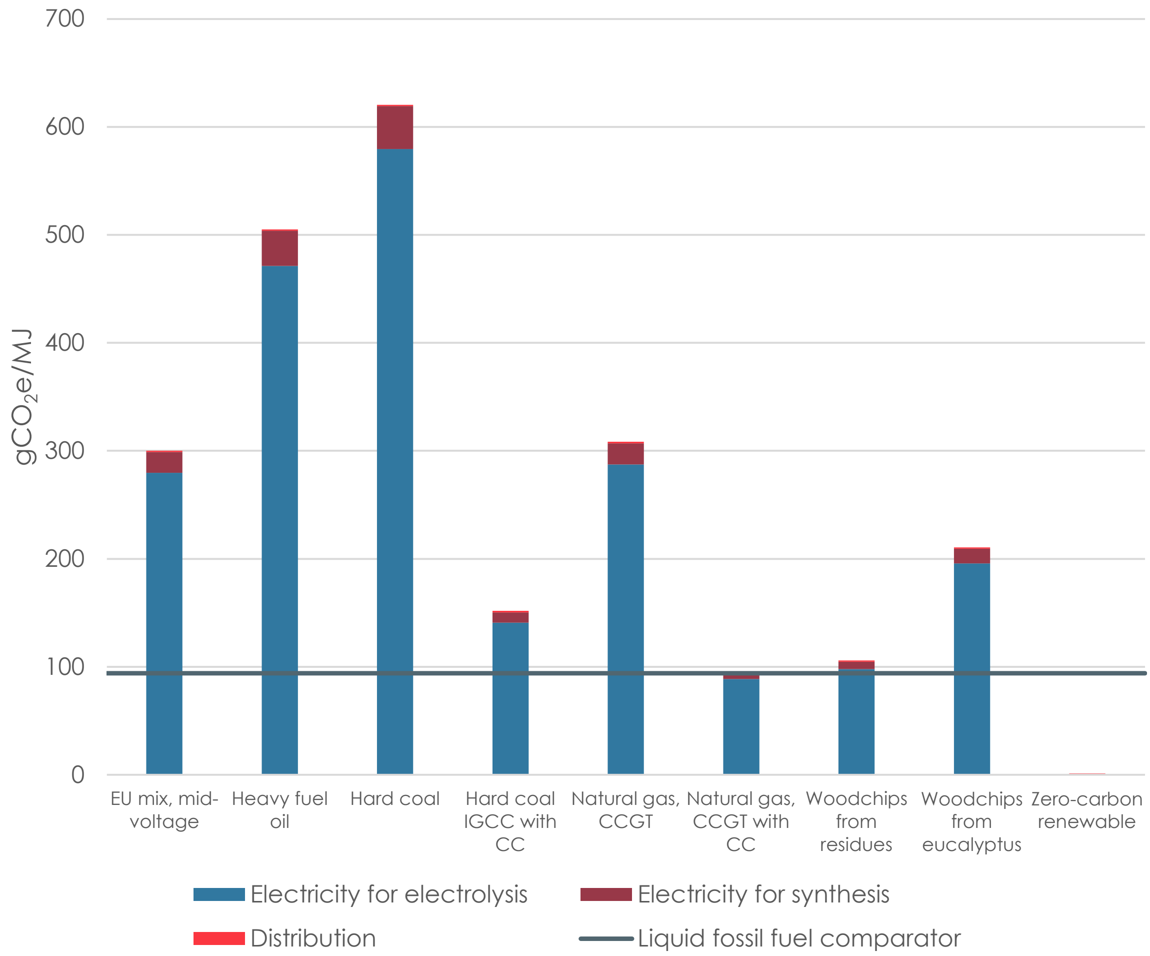

Figure 11. Lifecycle carbon intensity of electrodiesel production via methanol, based on energy consumption and electricity carbon intensities taken from the JRC well-to-wheels study

Schmidt, Weindorf, et al. (2016) report similarly low lifecycle emissions for renewable electrofuels, but note that construction emissions for renewable power generation facilities, which are generally excluded from the system boundary of alternative fuels lifecycle analyses, may represent a significant contribution to the lifecycle. They report an additional 10 gCO_2e/MJ associated with developing and constructing additional wind power, and 27 gCO_2e/MJ associated with developing and constructing additional PV capacity.

Renewability and additionality for electrofuels

It is clearly important for the environmental performance of electrofuels that production should be powered by low-carbon, renewable electricity sources. However, there is not yet a consensus at the policy level on how the renewability of electrofuels should be determined in the long term. Under existing European legislation in the RED, 'renewable fuels of non-biological origin', including renewable electrofuels, are eligible to be counted towards compliance with targets for the use of renewable energy in transport. However, at present the renewable content of electrofuels must be based on the average renewable content of electricity in the national or European grid. This represents a barrier to deployment of renewable electrofuels, as it precludes electrofuel producers from accessing the full value-per-litre of the incentives available to biofuel producers. For instance, an electrofuel producer in a state with 25% renewable electricity could only claim support for 25% of the volume of fuel supplied, effectively only receiving a quarter of the support available to a biofuel producer (analogously, this can be thought of as reducing the implied carbon dioxide price from the regulation by 75%).

The proposal for a RED II beyond 2020 includes a plan to alter this system, so that:

> *"electricity obtained from direct connection to an installation generating renewable electricity (i) that comes into operation after or at the same time as the installation producing the renewable liquid and gaseous transport fuel of non-biological origin and (ii) is not connected to the grid, can be fully counted as renewable electricity for the production of that renewable liquid and gaseous transport fuel of non-biological origin."*

This would represent an important step forward, allowing renewable electrofuel producers to receive support for the full volume of fuel supplied. It is not clear though that this proposal represents the best or only way to treat accounting or renewability for electrofuels.

The requirement that to be counted as fully renewable an electrofuel facility should be connected to a renewable electricity generating facility that is not grid connected is arguably an unnecessary barrier to efficient use of renewable electricity generating potential. Much renewable electricity generation, notably PV and wind power, suffers from intermittency. Constructing a fuel synthesis plant able to utilise maximum power generation from an off-grid renewable electricity plant would result in excess capacity that could not be utilised most of the time. This would increase investment costs relative to fuel output, making projects more difficult to finance. On the other hand, constructing a fuel synthesis facility smaller than the maximum power generation capacity would result in renewable electricity being wasted during times of peak generation, as excess electricity could not be exported to the grid under the accounting rules.

There is therefore a strong case to allow added flexibility in the rules for assessing renewability. The flip side of the flexibility question, however, is that if the rules are made too flexible it may be difficult to have confidence that electrofuel capacity deployment is actually linked to an increase in renewable electricity generation. As noted above, electrofuel production based on grid average electricity (in most countries) would deliver no environmental benefit. As noted by Bracker (2017), "To ensure synthetic fuel production does not lead to significant CO_2 emissions, the production process needs to be based on renewable electricity and cannot simply be operated by electricity from the grid."

One option that might be considered to demonstrate renewability would be the allocation of renewable 'guarantees of origin' to renewable electrofuels facilities to match the quantity of electricity consumed. This would create an association between the electrofuels facilities and renewable electricity generation, which could either occur at new or at existing renewable electricity plants. However, the assignment of guarantees of origin in this way does not create a requirement for any overall increase in renewable electricity generation, and so "the simple use of Guarantees of Origin, as they are currently used in Europe, does in no way ensure that power consumption for synthetic fuel production is based on additional renewable generation" (Bracker, 2017).

A proposal for an approach to allow identification of 'additional' renewable energy generation linked to specific consumers is provided by Tempe et al. (2017). This paper identifies two cases in which renewable electricity production utilised by an electrofuel facility could be considered additional supply, rather than supply already required to meet other policy goals:

- In the first case, they argue that a facility not receiving financial support from public support schemes for renewable electricity generation could be considered additional.
- In the second case, they argue that any renewable surpluses that would otherwise have been curtailed (due to oversupply) could be considered additional.

These would be managed by the issuance of what they refer to as 'GO-plus' certificates to confirm additionality of renewable electricity production.

The outline for GO-plus in Tempe et al. (2017) focuses on the case of new renewable electricity production facilities, however the same logic could be applied to existing facilities opting out of renewable electricity incentives in order to be able to trade GO-plus certificates to an electrofuel producer. In the case that EU targets for renewable energy production are binding (i.e. that electricity suppliers are forced by renewable energy targets to make investments that they may not otherwise have made in order to meet targets), this award of GO-plus certificates and cancellation of some amount of renewable electricity supply from the renewable electricity consumption inventory would force additional renewable power investment somewhere in the market, ensuring additionality. Such an approach would be analogous certification schemes in place in some Member States to allow flexibility in meeting biofuel targets.

If well-implemented, a system along the lines of the GO-plus proposal ought to be able to ensure environmental integrity of the EU renewable power market in the context of electrofuel capacity deployment. The key characteristics of an effective system would be that it effectively prevented a given megajoule of renewable power from being counted twice towards European targets or provided double incentives at the Member State level, and that electricity transferred into the transport market would have to be replaced by additional generation.

Renewability and additionality in the proposed Renewable Energy Directive

As applied to electrofuels, the first of the GO-plus criteria partly reflects language in the proposed Directive (European Commission, 2016b) that is intended to prevent renewable energy being double counted in renewable inventories. Article 7.1 of the proposal states that, "Gas, electricity and hydrogen from renewable energy sources shall be considered only once in [gross final consumption of electricity; gross final consumption of energy for heating and cooling; or final consumption of energy in transport]," and Article 7.4 clarifies that renewable electrofuels, "that are produced from renewable electricity shall only be considered to be part of the calculation [of the final consumption of electricity]." In practice, it is our understanding that this means that a Member State using the maximum possible supply of renewable electrofuels meeting its Article 25 target for use of renewable energy in transport would need to increase the supply of renewable energy for either electricity or heat and cooling compared to a Member State meeting its Article 25 obligations using only advanced biofuels. This language would not, however, require such a stringent additionality as called for by the GO-plus concept, due to the conflation of final consumption of energy as electricity vs. final consumption of energy as electrofuel. The overall conversion efficiency for electricity into electrofuels will likely fall around 40% for current facilities. At that efficiency, for every megajoule of renewable electricity diverted to electrofuel production, only 0.56 additional megajoules of renewable electricity generation would be required to meet Member State targets.

It's useful to take a moment to work through an example to show why this is the case under the proposed rules. Table 12 shows two cases for a simplified Member State with 100 TWh of energy consumption in transport and 300 TWh of energy consumption in other sectors. In the baseline case (middle column), the full transport renewable energy target is met with advanced biofuels (6.8 TWh worth, row 1). In the electrofuel case, the maximum allowable part of the renewable energy in transport target is met with 'renewable' electrofuels (3.2 TWh worth, row 2), with the remaining 3.6 TWh met with advanced biofuels.

Table 11. Example of renewable energy accounting for electrofuels in proposed RED II

Row no.	Final energy	Baseline	Electrofuel case
1	**Transport advanced biofuel**	6.8	3.6
2	**Transport electrofuel**	0.0	3.2
3	**Transport fossil**	93.2	93.2
4	**Total transport energy (final consumption)**	*100.0*	*100.0*
5	**Non-transport energy (final consumption)**	*300.0*	*300.0*
6	**'Renewable' electricity for electrofuel**	*0.0*	*8.0*
7	**Total energy (final consumption)**	**400.0**	**404.8**
8	**Non-transport renewable energy**	101.2	97.7
9	**Non-transport fossil**	198.8	202.3
10	**Renewables in transport**	***6.8%***	***6.8%***
11	**Renewable energy (final consumption)**	***27%***	***27%***
12	**Increase in renewable electricity generation / electricity used for electrofuels**		***56%***

Under the RED II rules, the supplied electrofuel is not counted towards overall final energy consumption, but the electricity input to the electrofuel production process is. Total final energy consumption in the EU is therefore higher in the electrofuel case by 4.8 TWh (8 TWh required as input to electrofuel production, minus the 3.2 TWh reduction in advanced biofuel use compared to the baseline). Under the overall renewable energy target, 27% of final energy consumption must be renewable. To meet this target in the baseline, 101.2 TWh of further renewable energy generation is needed. In the electrofuel case, however, only 97 TWh of further renewable energy generation is needed, because so much renewable electricity is already being consumed for electrofuel production. The flipside of this is that fossil energy generation remains higher in the electrofuel case than it does in the baseline, by 3.5 TWh.

The result, given the accounting rules in place, is that even if the 8TWh of electricity for electrofuel production meets the requirement for renewability in the proposed legislation (direct connection to electrofuel facilities), increasing the use of electrofuels instead of using advanced biofuels would allow the Member State to require less renewable energy generation in other sectors, and still meet its EU targets. Across the system as a whole, only 56% of the electricity for electrofuel production is truly additional renewable electricity.

This failure to set accounting rules in the RED to guarantee truly additional renewable electricity generation could severely undermine the climate benefit delivered by renewable electrofuel deployment. As shown in Figure 12, renewable electrodiesel produced with only 56% zero-carbon renewable power would have a greenhouse gas intensity of over 100 gOC2e/MJ, worse than fossil diesel. This result highlights the importance of developing a regulatory framework in which it is guaranteed that electrofuel production will be associated with a matching increase in renewable power capacity.

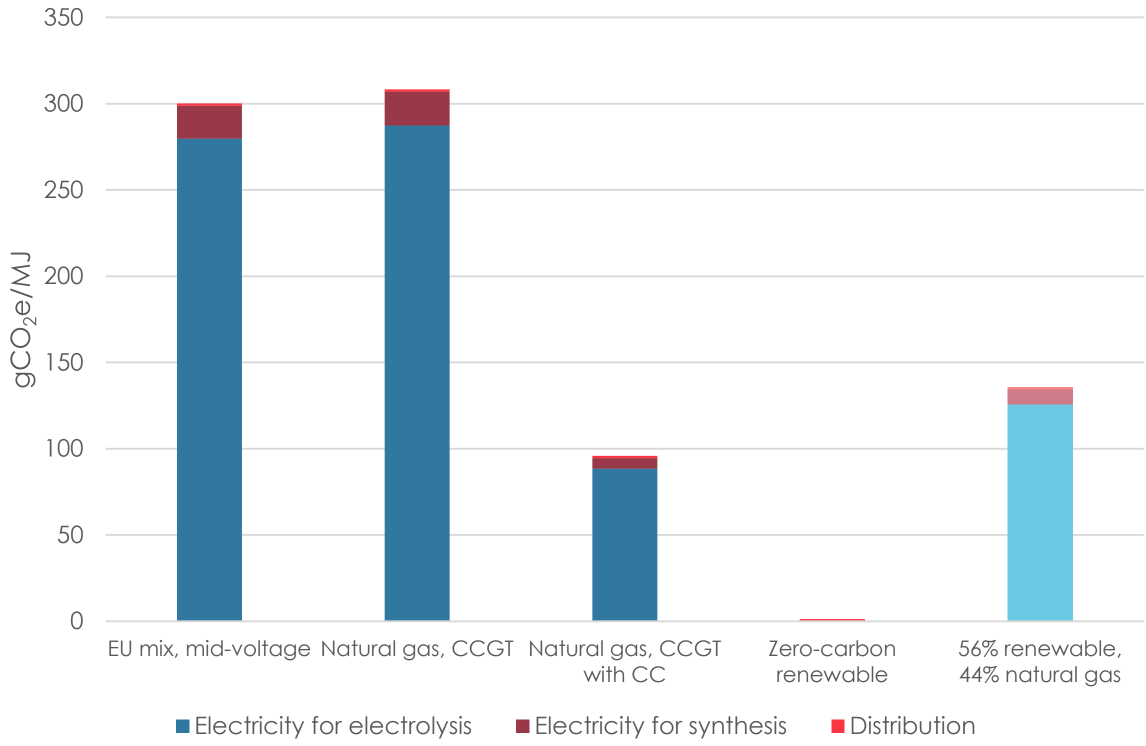

Figure 12. Lifecycle carbon intensity of electrodiesel produced from 56% renewable electricity, with comparators

This type of interaction between nested targets in renewable energy legislation is discussed in more detail as the 'renewable rebound' by Malins (2017), and emphasises the importance of policy that is coherent across different targets. It is important to emphasise that the fictional electrofuel producer(s) in the example above have themselves done nothing wrong. Our example assumes that they have made the appropriate investments (or worked with partners making the appropriate investments) to install new renewable electricity capacity. A lifecycle analysis at the facility level would still determine that the individual electrofuel producers were delivering greenhouse gas emission reductions. It is only at the policy level, because of poorly defined accounting rules, that we find that there is no real CO_2 benefit.

Non-CO2 impacts of aviation

In general, when considering the greenhouse gas footprint of fossil fuel use, the dominant climate impact is from the combustion of the fuel to produce carbon dioxide. For renewable alternative fuels, it is normally assumed that the carbon in the fuel would have also been in the atmosphere as carbon dioxide in a counter-factual scenario.

For aviation, however, there are additional climate impacts beyond the global warming potential of the carbon dioxide released. The formation of contrails and aviation induced cloudiness also has a significant global warming effect, and while there is considerable uncertainty in the estimation of these effects, they are believed to be on the same scale as the climate impact of fuel combustion (Hassink, 2012). Recent work by Moore et al. (2017) provides a basis to believe that the use of synthetic fuels in aviation, such as electrofuels, may result in a reduction in cloud formation, due to reductions in fine particle emissions from aviation engines, which are linked to cloud formation. The paper notes however that,

> *"Understanding the implications of these findings for future aviation-related effects on upper tropospheric clouds is complicated by the idea that, despite these potential reductions in the number of ice crystals, the frequency and ice mass of contrails may actually increase, owing to the 8% increase in the hydrogen content of the biofuel blend compared to petroleum-based fuel. However, it remains to be seen whether this increased water vapour in the early plume is relevant to contrail evolution after the vortex mixing phase, where the supersaturation of ambient water vapour with respect to ice is the primary driver of the persistence and ice mass of contrails."*

While additional research is required to provide a useful estimation of the magnitude and even sign of the effect of synthetic jet fuel use on non-CO_2 climate impacts of aviation, it is a question of considerable importance to a fuller evaluation of the relative merits of using alternative fuels in aviation vs. road transport applications.

Relative efficiency of low carbon options

One criticism that has been levelled at electrofuels is that in transport they represent an inefficient use of electrical energy when compared to use of electricity directly in electric drivetrain vehicles. Bracker (2017) comments that, "As the direct use of electricity is much more effective than synthetic fuels in terms of energy required for reaching a certain mobility output, the direct use of electricity via battery electric vehicles should be preferred to the less efficient use of synthetic fuels." The NGO Bellona has been more forcefully critical, noting for instance that, "powering Europe's road transport with such fuels would require well more than the entire current EU electricity generation. In comparison, a total shift to electromobility would add just ~24% to current electricity demand" (Helseth et al., 2017).

The basic observation that electric drive vehicles are more efficient than internal combustion engines (ICEs) is clearly correct. Similarly, it is also clearly true that the energy losses involved in supplying renewable electricity to homes to charge electric vehicle batteries are much lower than the losses involved in converting electric energy into liquid fuels and supplying those to ICE vehicles. For instance, Transport and Environment (2017) estimate that for representative cases, direct supply of electricity for battery charging delivers an overall 73% efficiency from electricity production to energy use in transport, while use of hydrogen in a fuel cell vehicle delivers only 22% energy efficiency and PtL electrofuels deliver only 13% overall efficiency. While it is reasonable to look to efficiency improvements in future for both electrofuel production technologies and the ICE, there is no prospect of this hierarchy of efficiency between battery electric vehicles and ICE vehicles running on PtL electrofuels being reversed.

The scenarios for fully renewable European transport in Schmidt, Zittel, et al. (2016) provide further characterisation of the limitations of electrofuels as an alternative to transport electrification. In their scenario with maximum e-mobility total electricity demand is reduced by 30% and total required investment by 25% (2 trillion Euros) compared to the scenario with the highest use of electrofuels.

This difference in overall efficiency likely proscribes electrofuels as a long-term energy solution for passenger vehicle transport. Several authors therefore emphasise electrofuels as a potential solution for aviation and marine applications that cannot be readily electrified (Bracker, 2017; Schmidt, Weindorf, et al., 2016). That said, while some decarbonisation roadmaps assume full electrification of passenger vehicles at least, many other projections anticipate significant ongoing liquid fuel demand for road transport in Europe in 2050, even in passenger cars. For instance, Schmidt, Zittel, et al. (2016) present a 'balanced' scenario for renewably powered transport in 2050 in which 70% of new registrations are still range-extended electric vehicles (i.e. electric drivetrains coupled to backup gasoline or diesel combustion), the DG Energy 'Energy Roadmap to 2050' assumes that only 65% of passenger vehicles will be electric by 2050, and the ECF *Roadmap 2050* assumes that 20% of passenger car sales in 2050 will be plug-in hybrids (the rest being fully electric) (Pavlenko, Takriti, Malins, & Searle, 2016). It is therefore reasonable to assume that there may be an opportunity for liquid electrofuels to contribute to road transport decarbonisation in the 2050 timeframe.

Water use

For biofuels, water consumption and water pollution is an important sustainability concern, due to the high water requirements of some bioenergy systems, and the risk of water pollution by agricultural production systems (Yeh et al., 2011). For electrofuels, water demand is likely to be much lower, and hence in general less of a concern. Electrofuel production uses water as a feedstock for electrolysis. Based on stoichiometric assessment, it can be calculated that about 1.4 litres of water will be required as an input for every litre of synthetic liquid fuel produced (Bracker, 2017; Schmidt, Weindorf, et al., 2016). This compares to between 1,400 and 20,000 litres of total water required per litre of first generation biofuel production (Dallemand & Gerbens-Leenes, 2013). The use of concentrating solar power (CSP) may however add significant additional water demand in the case of the use of wet cooling. Wet cooled CSP requires about 3 cubic metres of water per MWh of electricity produced (Hernandez et al., 2014). This is equivalent to 73 litres of water for every litre of output electrodiesel. This can be reduced by 90-95% by employing dry cooling, to between 4 and 7 litres per litre of fuel. Incidental water use associated with other renewable electricity generation (for instance for cleaning PV panels) may similarly represent a comparable or higher rate of water use than is required for the actual electrolysis.

While the water requirement of electrofuels production is very low compared to biofuels, there may be some case in which electrofuels could still cause additional water stress in already stressed regions. A 100 million litre per year PtL electrofuel plant using energy from dry-cooled CSP would require about 150 million litres per year of water for electrolysis, plus perhaps 500 million litres per year for the CSP. Developing a PtL industry based on concentrating solar power able to meet a large fraction of European transport energy demand would require hundreds of such plants. For instance, Schmidt, Zittel, et al. (2016) consider concentrating solar electricity production in North Africa as a low cost renewable electricity generation option. Bracker (2017) notes that, "The Middle East and North Africa (MENA region) are already today among the world's driest regions, and climate change will lead to a further increase in aridity in many regions of the world."

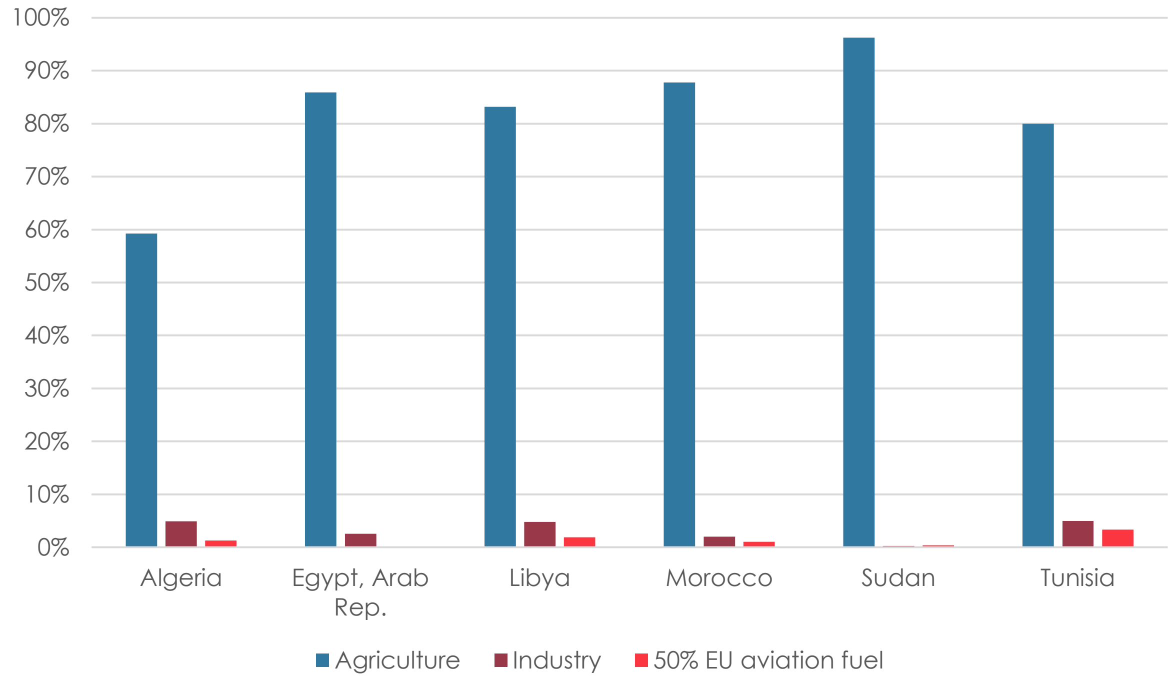

Figure 13. Percentage of national freshwater withdrawals used by agriculture and industry in 2014, and required to supply 50% of EU aviation fuel from electrokerosene

While the water availability issues facing arid regions in a future of climate change are serious, the development of electrofuels industries would not fundamentally alter the scale of water demand compared to existing patterns of water use, at least at the national level. Figure 13 shows that even for a very large electrofuels industry in any given country, producing an amount of electrofuel equivalent to half of European aviation fuel demand, freshwater removals for electrofuels production would be comparable to total existing industrial water use in any given North African country, but small compared to water use for agriculture.

Given the very large export revenue that would be associated with electrofuels export on this scale (of the order of 30 billion euros per annum, comparable to or above the total value of agricultural production in any of these countries), the water use required might be considered proportionate to the economic benefits derived to the national economy. Nevertheless, it is clear that for a very large electrofuels industry, water withdrawals could become significant enough to require careful oversight.

While water use for electrofuel production is unlikely to be problematic at the national level, there is still potential for rapid development of electrofuel production associated with concentrating solar power to impact water availability at a more local level, given that areas of highest solar irradiance may also be particularly dry. In the U.S., water availability issues associated with concentrating solar power production in arid areas of Southwestern States area have been investigated for the National Renewable Energy Laboratory (National Renewable Energy Laboratory, 2015). The report suggests that it might be appropriate for U.S. regulators to limit the use of wet cooling for CSP in order to reduce water demand, and notes that regulators in California in particular have shown a preference for projects using dry cooling. This would seem an appropriate sustainability requirement for any very arid area. More generally, it would seem appropriate to require that the local water supply impacts of any facility supplying fuel to the EU should be assessed against appropriate standards, analogously to the use of water sustainability rules in some existing biofuel certification schemes.

Bracker (2017) suggests that for arid areas, there could be a blanket requirement that new electrofuels facilities should utilise water from desalination. Given the relatively modest water demand of electrofuels production, such a requirement seems unduly stringent, but desalination may be an appropriate solution in specific cases where a proposed project site is in an area in which additional groundwater removals would be impossible or unduly environmentally problematic.

Land use and related issues

As in the case of water use, one appeal of electrofuels compared to biofuels is that they are dramatically less land intensive, given the much higher solar energy conversion efficiency of artificial renewable energy technologies compared to plant growth. For instance, Bracker (2017) reports that electrofuels production using photovoltaic or wind power in Germany should be able to deliver at least 500 gigajoules per hectare per year. This compares to areal yields for biofuels of around 100 gigajoules per hectare for sugar beet, 60 gigajoules per hectare for wheat or 40 gigajoules per hectare for rapeseed oil.[40] There is no requirement to use high quality agricultural land for renewable electricity generation, and indeed lower value land is likely to be more appealing to project developers for economic reasons. Renewable electricity generation facilities for electrofuels should be treated using the same planning rules that are applied to renewable electricity facilities generally. Renewable electricity generation is the most land intensive aspect of electrofuel production – facility siting should present no issues fundamentally different from those associated with siting any industrial facility, and in Europe should be dealt with adequately by existing planning systems.

40 https://www.forestry.gov.uk/fr/beeh-absfpx

Outside Europe there may be a higher likelihood of weak governance in existing systems, and therefore it may be appropriate to consider additional sustainability criteria on project siting that would apply to all projects supplying electrofuels to Europe. In general, there needn't be undue conflict between renewable electricity generation and environmental goods. Komendantova, Patt, Barras, & Battaglini (2012) report that stakeholders generally consider concentring solar power projects in North Africa to represent a low environmental risk, while Hernandez et al. (2014) note for the case of South Africa that 548 GW of concentrating solar power capacity could be developed in principle without affecting "habitats supporting endangered or vulnerable vegetation". McCrary, McKernan, Schreiber, Wagner, & Sciarrotta (1986) reported that mortality rates among birds were low in relation to solar power facilities compared to other anthropogenic causes of mortality, but Kagan, Viner, Trail, & Espinoza (2014) report on avian deaths associated with solar flux at a concentrating solar facility in California. They recommend several strategies to reduce the risk to birds from the facility in question, which may be applicable in some cases to new facilities in North Africa and elsewhere:

- Increase cleared area around solar tower to decrease attractive bird habitat in vicinity of tower.
- Fit visual cues to panels.
- Suspend power tower operation during peak migration periods.
- Avoid vertical orientation of mirrors when possible (e.g. tilt when cleaning).
- Place perch deterrents where appropriate in vicinity of tower.
- Prevent bat roosting.

Overall, while some negative impact is clearly possible, Hernandez et al. (2014) conclude that "[utility scale solar energy] systems have low environmental impacts relative to other energy systems, including other renewable energy technologies."

Suggested regulatory environmental safeguards

Above, we outlined a range of potential environmental issues that could be associated with an expanding electrofuels industry. This section proposes a set of measures that could be implemented at the regulatory level, or voluntary by operators, to guarantee the sustainability and environmental benefits of growing the renewable electrofuel industry.

Renewable energy accounting

As detailed above, it is vital for the climate performance of electrofuels that they are produced using truly additional renewable electricity. If expansion of electrofuel capacity uses fossil electricity from the grid, it will not deliver climate benefit. If expansion of electrofuels is associated with new renewable power capacity, but due to renewable energy accounting rules this results in less renewable power capacity being deployed elsewhere, the policy framework will not deliver climate benefits.

The GO-plus concept detailed by Tempe et al. (2017) appears to provide a flexible, readily implementable approach to ensure additionality of renewable electricity for electrofuel production in the context of broader renewables policy. Renewable energy accounting rules in the RED should be adjusted so that the use of renewable electricity for renewable electrofuel production is not counted as 'final consumption' of renewable energy. By removing renewable electricity used to produce electrofuels from both the numerator and denominator of overall renewable energy targets, additionality of generation could be demonstrated. Renewable electricity suppliers would be permitted to register their output for 'GO-plus' certificates[41], which would require the same amount of electricity generation to be excluded from receipt of other renewable power generation incentives. Renewable electrofuel producers would be required to obtain and relinquish a number of GO-plus certificates corresponding to their electricity consumption for electrofuel production. This system could be applicable to the case of facilities connected to a single power generation facility, but would also allow facilities connected to the grid to demonstrate that they were using additional renewable electricity (i.e. additional to the renewable electricity generated to meet other targets). This system ought to be extended to any production of electrofuels outside Europe, which should be clearly linked to additional renewable electricity capacity that is demonstrably not being registered for compliance with climate policy in third countries. In the absence of such a certification system for renewable electricity, requiring direct connection of electrofuel facilities to renewable power facilities would create some impetus for additional renewable electricity generation, but would be likely to deliver only 56% renewability across the system as a whole.

Carbon dioxide sources

As discussed above, in the short to medium term there is little prospect of the supply of carbon dioxide from point sources in Europe being exhausted either by reduced emission or by

41 Or some analogous tracking scheme in which the electricity supplied for electrofuel production was otherwise rendered ineligible for other renewable support.

increases in carbon sequestration and storage. In terms of net CO_2 fluxes to the atmosphere, there is therefore no difference in the short to medium term between renewable electrofuels produced using CO_2 containing fossil carbon collected from point sources as opposed to renewable electrofuels produced using CO_2 containing biogenic carbon from point sources or CO_2 from atmospheric capture. For this reason, in the period 2020 to 2030 it is proposed that the origin of CO_2 for fuel synthesis need not be regulated, except to prohibit the purposeful combustion of material to produce carbon dioxide for electrofuel production. We differ in this respect from several previous studies, mentioned above, which have argued that only CO_2 from atmospheric capture and/or CO_2 from oxidation of biogenic material should be permitted as a feedstock for fuel synthesis. It would be appropriate to grandfather the eligibility of point CO_2 sources to be treated this way until 2040, in order to provide investment confidence. Beyond then, facilities may reasonably be expected to transition to atmospheric capture, if it is determined that it is no longer appropriate to assume continued CO_2 emission from a given point source in a counter-factual scenario.

While we consider this appropriate in the short to medium term, likely until at least 2040 given the likely respective pace of industrial decarbonisation and even a relatively rapid deployment of electrofuels, in the longer term concerns about a renewable electrofuels industry becoming an excuse not to deliver deep decarbonisation are valid. It is therefore suggested that the European Commission should signal, first through communications and later through regulation, that beyond a chosen year (such as 2040) only renewable electrofuels produced using CO_2 from non-fossil sources should be eligible for policy support. Providing a clear indication of a proposed switchover date well in advance would allow electrofuel developers to take advantage in the short term of the flexibility of being permitted to utilise fossil CO_2 streams, while planning in the long term for investments to install atmospheric capture capacity (or otherwise switch to an alternative CO_2 stream). This phased approach ought to guarantee environmental integrity, while not placing unnecessary barriers in the way of industrial development.

Carbon dioxide accounting

While allowing electrofuels to be produced using fossil carbon dioxide need not undermine climate goals in the short to medium term, it is important that carbon dioxide used by electrofuels should be correctly accounted, and in particular that any utilisation of fossil carbon dioxide should only be credited once towards EU climate policy. It is likely that some industrial operators capturing CO_2 for supply to electrofuel synthesis plants will argue that they should receive ETS credit for doing so, as if the CO_2 were to be sequestered permanently. If such a credit were given, it would be consistent to treat the CO_2 as sequestered (from an LCA point of view) when it reaches the system boundary of the electrofuel production facility – and therefore fully count combustion emissions for the fuel against the electrofuel facility, eliminating any potential to account carbon savings to the fuel.

As this consistent treatment would eliminate the possibility to credit electrofuels as a transport sector decarbonisation tool, it would be better for industrial facilities should be held accountable under ETS for any CO_2 supplied to electrofuel production, in order that the fuel itself may consistently be treated as carbon neutral. This would create a fair market competition between carbon sequestration and electrofuel production as users of captured CO_2. Failing to introduce such accounting rules would result in inaccurate overall inventories, and perverse incentives to industrial operators to choose CO_2 utilisation pathways that result in emission above those that result in sequestration.

Greenhouse gas intensity

The primary mechanism to guarantee a low greenhouse gas intensity for renewable electrofuels is to ensure that the electricity consumed for electrolysis represents additional renewable capacity. When zero carbon renewables (wind, PV, concentrating solar, hydropower, tidal power) are utilised, electrofuels will have a very low greenhouse gas intensity. *Provided that condition is met,* we are not aware of any further risks of indirect emissions or of high direct emissions comparable to the high emissions seen for some biofuel pathways (Malins, Searle, & Baral, 2014).

The case of renewable electricity from biomass combustion is a special case, as renewable electricity from biomass combustion is not generally zero carbon (Baral & Malins, 2014). Given the inefficiencies in fuel synthesis from electricity, the carbon intensity of electrofuels will be 2 to 3 times higher than the carbon intensity of the input electricity. An electricity supply with a low carbon intensity of 25 gCO_2e/MJ would result in electrofuels with a disappointing carbon performance (20-47% carbon savings). As noted above, even with almost 100% carbon savings, renewable electrofuel production will need a very high implied carbon price from policy support to be viable. In that context, anything other than near-carbon-neutrality should not be considered acceptable.

The question of carbon accounting for biomass combustion is controversial, and well beyond the scope of this paper. Given the significant possibility that, due to carbon debt and land use change issues, biomass power in Europe and elsewhere will not be close to carbon neutral, it is suggested that only 'zero carbon' renewable electricity sources should be allowed to be used for renewable electrofuel production (for instance by providing GO-plus certificates). *Provided electrofuels are produced only with demonstrably additional zero-carbon renewable electricity, a low greenhouse gas intensity should be guaranteed.*

Water use

Water use is considerably less of a concern for electrofuel production than it is for biofuel production. Nevertheless, responsible water consumption should be a precondition of access to EU support for electrofuels. Concentrating solar power in arid climates appears to be the highest risk case for excessive water use in the electrofuel production chain. It is therefore suggested that facilities using concentrating solar power as renewable electricity source should be required to undertake basic water availability assessments, and that where water availability is limited more substantial water use plans should be required. Existing biofuel sustainability schemes may provide useful examples of how this requirement could be implemented.

Other

The other environmental risks associated with electrofuels, and renewable electricity generation for electrofuels, are common to industrial facilities and renewable electricity generation facilities generically. Because of the much smaller land footprint of electrofuels than biofuels, and the option to place renewable energy production on non-agricultural land, the environmental risks are proportionately smaller. Within the EU, these issues ought to be addressed through planning rules and existing biodiversity protections. If issues arise, rules should be implemented applicable to all renewable power generation, not only to electrofuels.

Outside the EU, there may be less stringent environmental and biodiversity protection. It may therefore be appropriate to require environmental impact assessment and biodiversity monitoring, especially for any ecosystems identified as at high risk from development. Again, these issues will be common to electrofuels and other renewable power facilities, and mechanisms appropriate to electrofuels should ideally be applied for any renewable energy imports to the EU.

Summary

In order to limit the environmental impact and ensure the environmental integrity of future electrofuels production, the following regulatory rules requirements are suggested:

1. Renewable electricity used for renewable electrofuels should be additional to renewable electricity generated for compliance with existing EU targets. This could be implemented by providing certificates to renewable electricity generators for opting out of being counted and incentivised in existing renewable electricity policies, to be redeemed for compliance by electrofuel suppliers. With such a certificate system in place, direct connection to renewable power generators may not be necessary.
    a. For imported electrofuels, a comparable requirement should be imposed that renewable electricity consumed for electrofuels supplied to Europe should not be counted towards any domestic targets.
2. The provenance of CO_2 for electrofuel production should not be limited to either atmospheric capture or biogenic combustion.
    a. This rule should be reviewed in 2030, with the possibility of requiring atmospheric capture after 2040.
3. Greenhouse gas emissions reductions from electrofuels should be attributed to either the electrofuel or the facility capturing the carbon dioxide, and never to both.
4. To guarantee that renewable electrofuels should have low lifecycle greenhouse gas intensity, only zero-carbon renewable power generation should be eligible for certification and use in renewable electrofuel production.
5. For any electrofuel facility using renewable solar power generated in an arid environment, a water use impact assessment should be required. For concentrated solar power in arid environments, dry cooling should be required.
6. The EU should consider requiring environmental impact assessment for facilities importing energy to the EU, either directly as electricity, or as electrofuels.

What would be required to accelerate the deployment of a renewable electrofuels industry?

As detailed above, the relatively high cost associated with electrofuel production represent a significant short-term barrier to the development of a successful electrofuels industry. The embryonic industry will not be able to match or come close to the relatively low production costs of fossil fuels, and likely would also not be competitive with advanced biofuel production until at least 2030. For an electrofuels industry to take off, it is clear that considerable public support will be required.

Renewable electrofuels in RED II

As a starting point, it is worth considering the policy framework that is currently proposed to apply to electrofuel production in the period 2020 to 2030. Under the proposal for a new Renewable Energy Directive (European Commission, 2016b), electrofuels would be eligible to count towards targets for advanced renewable transport fuel use, and the electricity fed into electrofuel production would also be eligible for renewable electricity production support. As currently drafted, the full rate of support would only be available to facilities with a, "direct connection to an installation generating renewable electricity that comes into operation after or at the same time as the installation producing the [electrofuel]." Facilities connected to the grid would only be able to claim renewability on the "average share of electricity from renewable energy sources in the Union or the share of electricity from renewable energy sources in the country of production".

Some insight into the potential value from policy for renewable electricity generation can be inferred by looking at the past value of renewables certificates under existing legislation. Research for the European Parliament (European Parliamentary Research Service, 2016) found that in 2012 the average value of support for renewable electricity generation in the EU was 12 €cent/kWh.

As a specific Member State example, under the UK Renewables Obligation, the reported value of a 'Renewables Obligation Certificate' in October 2017 was about €55 per certificate[42]. Different numbers of certificates are awarded to different technologies; based on current banding, the value of policy support for largescale solar PV is about 7 €cent/kWh, the value of support for onshore wind is 5 €cent/kWh and the value of support for offshore wind is about 10 €cent/kWh. These are very significant incentives, with the value of policy support being comparable to the wholesale electricity price. For a zero-carbon solar PV plant displacing natural gas power, we calculate that the Renewable Obligation Certificate provides an implied carbon abatement value of about 200 €/tCO_2e. For an integrated electrofuel facility with on-site solar PV, the value of the incentive is effectively multiplied (as at current efficiencies each megajoule of output fuel inherits the incentive from two and a half megajoules of input power). We calculate that under the Renewables Obligation system, such an integrated

42 http://www.epowerauctions.co.uk/erocrecord.htm

electrofuel facility would benefit from an implied carbon price of about 550 €/tCO_2e. At that level, renewable electricity credits would clearly be extremely valuable to electrofuel production, dramatically reducing the effective cost of electricity to the electrofuel facility.

While this is the case under the existing Renewables Obligation system, in the UK the support system for renewable electricity is changing (for new plants) from the Renewables Obligation to a system of Contracts for Difference (CfD), in which renewable power generators are guaranteed a certain minimum price for their electricity. As noted above, the published 'strike prices' for renewable electricity under this system go as low as 6.4 €cent/kWh for offshore wind. The premise of the CfD system is that renewable power generators will offer strike prices similar to their cost of production, and that government support will only be necessitated in the event that wholesale electricity prices do not cover that strike price. Unlike the Renewables Obligation system, this system would not support very low-price subsidised electricity to an electrofuel operator – rather it could guarantee a moderate electricity price. Calculating the implied carbon abatement price for such a scheme is more complicated than for a renewables credit, but certainly it would not be as potentially valuable to an electrofuels operator as the previous system. It is beyond the scope of this paper to review renewable electricity support schemes across the whole EU, but the takeaway message from comparing the old and new UK schemes is that there is potential for eligibility for renewable electricity credits to provide a large value to electrofuels producers, but that the actual value proposition will be highly dependent on how support is structured. Historical support value may be a poor guide to the value of renewable electricity support in the next decade,

For the value of policy for renewable energy in transport, one can look to the case of advanced biofuels, likely to be the primary competitor for renewable electrofuels if the RED II was passed as currently proposed. Peters et al. (2016) point to carbon abatement costs of 160 – 310 €/tCO_2e for *n*th of a kind advanced biofuel plants. For advanced biofuel production to expand at the sort of rate necessary to meet the proposed 3.6% minimum share of transport energy by 2030, and to fill some of the additional 3.2% share for which biofuels will compete with renewable electrofuels and waste-based fossil fuels, it can reasonably be assumed that the value of support offered by policy would need to be above this range, so implied carbon prices of the order of 350-450 €/tCO_2e are certainly not out of the question.

Taken together, under the proposed RED II framework it is not at all out of the question that the combined value of renewables support available to electrofuels could reach 600 €/tCO_2e or more, in some Member States at least. In principle, this could make electrofuel production viable for expected production costs up to about 3,000 €/toe, although as noted earlier it is important to bear in mind that investment happens based not on the actual value of policy support, but on a number based on the expected level of support, discounted for the uncertainty that arises from variable certificate values, risk of political change, and not being able to precisely forecast the success (or failure) of competitor industries. Just as advanced biofuel production has failed to meet target rates under valuable existing policies in both the U.S. and EU (Miller et al., 2013; Peters et al., 2016), so there is considerable risk that the proposed RED II framework will fail to deliver the level of investment that it should if investors had full confidence in its value proposition.

It is also vital to recognise that, as discussed above, the proposed RED II likely is not adequate to ensure that electrofuel production actually results in additional renewable electricity generation. The implied carbon prices detailed above are predicated on a renewable electrofuels industry with very low carbon intensity. Because of the interaction of the various targets in the proposed legislation, this may well not be the case – the net impact of electrofuels development on the EU electricity sector would be a combination of additional renewables and additional (new, or more likely not discontinued) fossil fuelled power generation. For that case, there may well be no system wide carbon saving at all, or else an implied carbon price an order of magnitude higher if savings are very small.

A possible alternative framework for electrofuels in RED II

The policy framework proposed for electrofuels under the RED II has several limitations. Firstly, there is the problem detailed above that even with the requirement for direct connection of facilities to renewable power facilities, given the way the overall targets are structured electrofuels need not be associated with additional renewable power capacity. Secondly, there is the opposite issue that by tying electrofuels production to specific renewable power plants, the legislation may eliminate some options for electrofuel production to assist with grid balancing that could be delivered with a robust system of renewability certification. Thirdly, there is the issue that the proposed framework in which electrofuels producers would be eligible for two sets of incentives may over-compensate electrofuel producers as compared to biofuels producers (and other emissions reduction projects), and adds complexity to the regulatory framework for all concerned.

There are few perfect answers in policy, but we believe that it would be possible to develop an alternative system of accounting and incentives for the RED II that would be more transparent, provide a clearer value proposition, better guarantee renewability of additional electricity production and provide more flexibility for electrofuels facilities to provide demand management services to the grid. Such as system would have the following characteristics:

- Use of electricity as an input feedstock for electrofuels would not count as final energy consumption under the REDII, either for the calculation of total EU final energy consumption or of total EU final renewable electricity consumption. Electrofuels would therefore count and be incentivised entirely within the transport target of RED II.
- To implement this accounting principle, there would be a system under which renewable power facilities were required to opt either to receive renewable electricity generation incentives, ***or*** to provide electricity to electrofuels facilities. This could be administered through a system comparable to the 'GO-plus' certificates concept developed by Tempe et al. (2017).
- Excess renewable electricity that would otherwise be curtailed should also be counted as additional (Tempe et al., 2017).
- Electrofuel facilities would be required to demonstrate the additional renewability of their electricity supply by obtaining and redeeming these additionality certificates from renewable power generators. Assuming such a system is implemented, the renewable power generators need not be directly connected to the electrofuels plants.
- Alternately, additionality could be guaranteed in a less flexible fashion by requiring direct connection to non-grid-connected facilities that opt out of receiving renewable electricity generation incentives.

- Renewable electrofuels should be eligible to count towards some part of the target for advance alternative fuels in the transport sector.
- Government should seek to ensure that electrofuel suppliers have access to variable electricity price markets, in order that they can provide grid balancing services by responding to relevant price signals.
- Research and development support should be provided to key technologies to improve the efficiency of electrolysis, such as solid oxide electrolysis.

Under this system, the primary value signal to electrofuel production would clearly come from the eligibility of electrofuels for alternative transport fuel targets. Electrofuel production would not be eligible for multiple incentives on the same renewable energy production. It is our opinion that requiring electrofuels to rely on a single incentive provides more transparency and clarity to both policy makers and economic operators. It is clear that disqualifying electrofuel production from incentives for renewable electricity generation will potentially reduce the strength of the business case for electrofuel development. The system under the proposed RED II, however, would over-incentivise electrofuel production compared to the environmental benefits delivered, and could be seen to create a perverse incentive to maximise the use of renewable electricity for electrofuel production instead of in direct supply for electrified transport modes.

Policy makers need to assess the evidence on the role that electrofuels can and should play in a future energy system, and come to an explicit conclusion on whether they feel electrofuels warrant greater support than other alternative fuels, such as advanced biofuels. ***If*** policy makers conclude that electrofuels warrant a higher value of support, then this enhanced support should be given explicitly, for instance through ring-fencing part of the renewable energy in transport target under the RED II, or by devising an entirely new support system. Additional support ***should not*** be given surreptitiously by rewarding both the consumption of the renewable electricity to produce the electrofuel and the consumption of the electrofuel itself, as such a double-counting system undermines environmental integrity and lacks transparency.

Discussion

Creating an EU electrofuels industry will not happen without significant government intervention. Based on our understanding of the costs of electrofuel production, it is impossible to imagine liquid electrofuels beating fossil fuels on carbon-unadjusted price in the period to 2050, and difficult to see them competing directly with advanced biofuels in the next decade. As things stand at the time of writing, we would be surprised to see electrofuels make a significant contribution to 2030 targets for renewable energy in transport, although this could in principle change as the proposed RED II is amended before its final adoption.

The primary policy support mechanism that is on the table for electrofuels is the Renewable Energy Directive, through the mandate for renewable advanced fuels in transport. Mandates of this sort have a history of being effective in supporting and expanding the supply of fuels that have already been commercialised and have a low technology risk and a clearly understood cost profile. The record of mandates in promoting the development of unproven technologies that require high capital expenditure is rather more questionable. As noted by Miller et al. (2013), no attempt to date to expand advanced biofuel production through support under an energy mandate has come close to delivering the levels of supply hoped for when the mandate was introduced. There is a strong case to be made that mandates of this sort are not effective policy tools for developing new technologies, due to the value uncertainty built into mandates by design. From the point of view of minimising the cost to taxpayers and consumers of renewable energy policy, it is appealing to create a market system under which the value of the incentive is intended to be minimised through competition. When considering a twenty year investment in a first-of-a-kind facility, this same value uncertainty is potentially insurmountable. European policy makers and regulatory officials would be well advised to consider seriously the options to introduce additional long-term value certainty into renewable fuel policy for specific cases in which new technology development is prioritised. This could include finding ways to set caps and ceilings on the value of policy support, setting defined long term tax incentives instead of or as well as mandates, or offering long term guarantees on subsidised renewable electricity to electrofuel facilities.

With the right investment support and production incentives, an electrofuel industry could undoubtedly be developed. Perhaps the most important question for policy makers at this time is how serious they are about electrofuels as a significant contributor to EU decarbonisation, what price they are willing to pay for that contribution, what time frame they expect electrofuels to become important within and why (if at all) electrofuels should be prioritised for development above other less costly decarbonisation options. In undertaking this review, we have not found evidence to clearly convince us that policy makers yet have an adequate understanding of the costs and benefits of electrofuels to make these decisions in an informed way.

As we have reiterated *ad nauseam* in the body of this report, the biggest element of the cost equation for electrofuels is the cost of electricity. It may be that it is premature to make significant investment in electrofuel production until business models can be more clearly presented that would deliver renewable electricity at 3 €/kWh or less to electrofuel producers. This would require confidence that the lower end of cost projections for levelised cost of renewable electricity production could be delivered, or else a much clearer and more fully explored vision for the valorisation of grid balancing services by electrofuels producers. At the point where there is a clearly understood pathway in place to 3 €cent/kWh renewable electricity supply, the case to invest heavily in electrofuels will be profoundly more compelling.

Even if the costs of electrofuel production are considered proportionate to the benefit, policy makers must also be realistic about the strain that a largescale electrofuel industry could place on the decarbonised electricity supply. To supply 50% of EU aviation fuel from electrofuels in 2050 would require a quarter as much electricity as is currently generated in the whole of the EU. This is a very large expansion to deliver decarbonisation of half of the energy supply for one mode of one economic sector. At this level of electricity demand, the grid that electrofuels could help balance would have to be significantly larger than it would be otherwise. This said, it remains true that it is unclear what other options there are to reduce the greenhouse gas intensity of aviation fuel use, except to reduce fuel burn entirely by reducing rates of demand growth. Notwithstanding the challenges, drop-in electrojet may be the best technological option available to deliver deeper decarbonisation of EU transport than is possible through efficiency improvements, operational measures and advanced biofuels alone.

For the foreseeable future, electrofuels are likely to be a more expensive climate solution than efficiency standards, electrification or advanced biofuels from sustainably available waste and residues. To reiterate the point made by Bünger et al. (2014), electrofuels might best be seen as the weapon of last resort to decarbonise activities for which there are truly no less costly alternatives, and "it is therefore vital to explore all available options for the reduction of energy demand and increase of vehicle efficiencies."

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