IRENA REPORT

IRENA

International Renewable Energy Agency

ROAD TRANSPORT: THE COST OF RENEWABLE SOLUTIONS

Preliminary Findings

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organization that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low carbon economic growth and prosperity.

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ROAD TRANSPORT:
THE COST OF RENEWABLE SOLUTIONS

June 2013

PREFACE

Of all the sectors of global energy use, renewable energy currently contributes the least to the transport sector. Often, efforts to promote renewable energy focus heavily on the power-generation sector. While renewable power is critical to a sustainable global energy future, achieving this calls for a far more integrated approach, taking into account all of the ways we consume energy in our diverse economies and daily lives.

The analysis presented in this report – the latest in an expanding series of cost studies from the International Renewable Energy Agency (IRENA) – suggests that the outlook for renewable energy in transport to 2020 could be very positive, as long as current policy support is enhanced and expanded.

Significant policy efforts across a wide-range of countries have resulted in rapid growth for conventional biofuels since 2000, starting from very low levels. The growth rate has slowed lately, with production costs for conventional biofuels – linked to food-based feedstocks – rising in line with global food prices.

However, policy support for advanced biofuels, including a wider range of feedstock sources, has prompted research, development and demonstration projects that have led to the construction of the first commercial-scale advanced biofuels plants. With as many as 15 commercial-scale advanced biofuels plants to come online within a few years, more meaningful cost data is starting to emerge. The signs are promising: a range of technology pathways are being explored, amid competition to prove the efficiency, reliability and "up-scalability" of innovative new renewable transport fuels. These plants, if successful, will lead to larger more economic plants that could provide large reductions in greenhouse gas emissions at costs equal to or less than fossil fuels by 2020 if policy support is expanded.

Electric vehicles are also part of the intensifying competition, with mass-produced plug-in hybrids and pure electric vehicles appearing from a range of manufacturers, amid encouraging signs for mass commercialisation. Costs will come down with further deployment, making the outlook for electric vehicles in 2020 promising, as long as support policies are enhanced and investment in the necessary recharging infrastructure grows. Biomethane could be an important transport fuel, but similarly may need investment in refueling infrastructure to promote uptake.

These rapid developments in transport are mirrored in other sectors and IRENA's costing work - notably on power generation, but in the future for stationary applications as well – is designed to ensure policy and investment decisions are based on up-to-date, verifiable data. We are deepening our engagement with industry through the IRENA Renewable Costing Alliance in an effort to collect the data that will allow more comprehensive and detailed analysis of these issues in the future.

The findings for the transport sector are preliminary, given we are only just seeing commercial deployment of advanced biofuels and electrification for road transport. The next 18 months will reveal critical information about these technologies and their costs. IRENA will follow these exciting developments closely and will revisit the costs of these technologies once more data emerges.

However, what is clear is that these important breakthroughs can only be achieved if support policies are enhanced and expanded. Delaying, or rolling back, support for advanced biofuels would endanger the progress made towards aspirational targets for future years. Yet the growing body of cost data and analysis is highly encouraging. While the road just ahead is challenging, we can now see the beginnings of widely available, competitive renewable options for transport.

Adnan Z. Amin
Director-General, IRENA

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Executive Summary

The costs of advanced biofuels, electric vehicles, and biomethane for transport could be competitive with fossil fuel options by 2020 in an increasing number of market segments, as long as support policies are enhanced and expanded.

Although the current climate for renewables in transport is challenging, the analysis in this report highlights that the outlook for the future is increasingly positive. If support policies are expanded and enhanced, advanced biofuel technologies to produce biodiesel and ethanol could be competitive with fossil fuels by 2020, while plug-in hybrid electric vehicles (PHEVs) and pure electric vehicles (EVs) could provide mobility at comparable overall costs to internal combustion engine (ICE) powered vehicles by 2020 in an increasing range of market segments. Biomethane expands the renewable options for transport and when produced from wastes can provide a very competitive transport fuel.

These recent developments are welcome, as the transport sector currently lags other sectors in terms of the penetration of renewables.

In 2010, renewables accounted for just 2.5% of total transport and 3.3% of road transport energy consumption. This is the lowest penetration of renewables of any end-use sector. Significant policy efforts across a wide-range of countries to boost the use of renewables have resulted in rapid growth in the use of conventional biofuels since 2000, although the rate of growth in conventional biofuel use, worryingly, has slowed to very low levels in the last two years.

With ethanol production of around 80 billion litres and biodiesel production of around 24 billion litres in 2012, conventional biofuels dominate total biofuels production, as well as the overall contribution of renewables to road transport.

However, new renewable solutions are emerging as advanced biofuel plants have started to be built at commercial scales, PHEVs and EVs are now being mass produced, and biogas can provide a low-cost fuel from wastes. Question marks remain about which advanced biofuels pathways will offer the least cost fuels and how fast battery costs for PHEVs and EVs will come down. Even so, the fact that today we can measure progress on these two issues in the market place, with actual prices, represents significant progress from a year or two ago.

Conventional biofuels, derived essentially from food-based feedstocks, have seen their production costs increase in recent years due to high food prices. The outlook to 2020 for conventional biofuels is mixed, as food prices are projected to remain high.

Total production costs for conventional ethanol and biodiesel plants are dominated by feedstock costs. This makes the economics of production heavily dependent on movements in the local and global markets for the feedstock used. Between 2005 and 2012, global corn prices rose by around 120%, while between 2007 and 2012, the sugarcane prices paid by ethanol producers in Brazil increased by two thirds. The feedstock costs of biodiesel also increased between 2005 and 2012; by 87% for soybean oil and 49% for rapeseed oil.

In 2012, conventional ethanol produced from corn in the United States was therefore estimated to have cost between USD 0.9 and USD 1.1 per litre of gasoline equivalent (lge) to produce, while Brazilian sugar cane ethanol was estimated to have cost between USD 0.7/lge and USD 0.9/lge (Figure ES.1). The cost of ethanol from other grains (e.g. wheat) was higher. This compares to average refinery wholesale prices in the United States, with monthly averages between USD 0.72/litre and USD 0.84/litre in 2012 for gasoline.

Conventional biodiesel production costs from soybean and rapeseed oils in 2012 were estimated to have averaged around USD 1.3/litre of diesel equivalent produced. Biodiesel produced from palm oil in Malaysia and Indonesia was estimated to have lower production costs, around USD 1/litre.

Current projections of global food prices to 2020 – and hence also the main production costs for conventional biofuels – are for prices to remain high and even increase for some food crops. The outlook for 2013 is slightly better than this long-term view, with expectations that prices for corn and some other food crops will ease from 2012 levels on the back of higher production in 2013. The outlook for conventional biofuels to 2020 is therefore for modest growth in production costs, albeit with some reductions in costs from 2012 levels anticipated within the next few years.

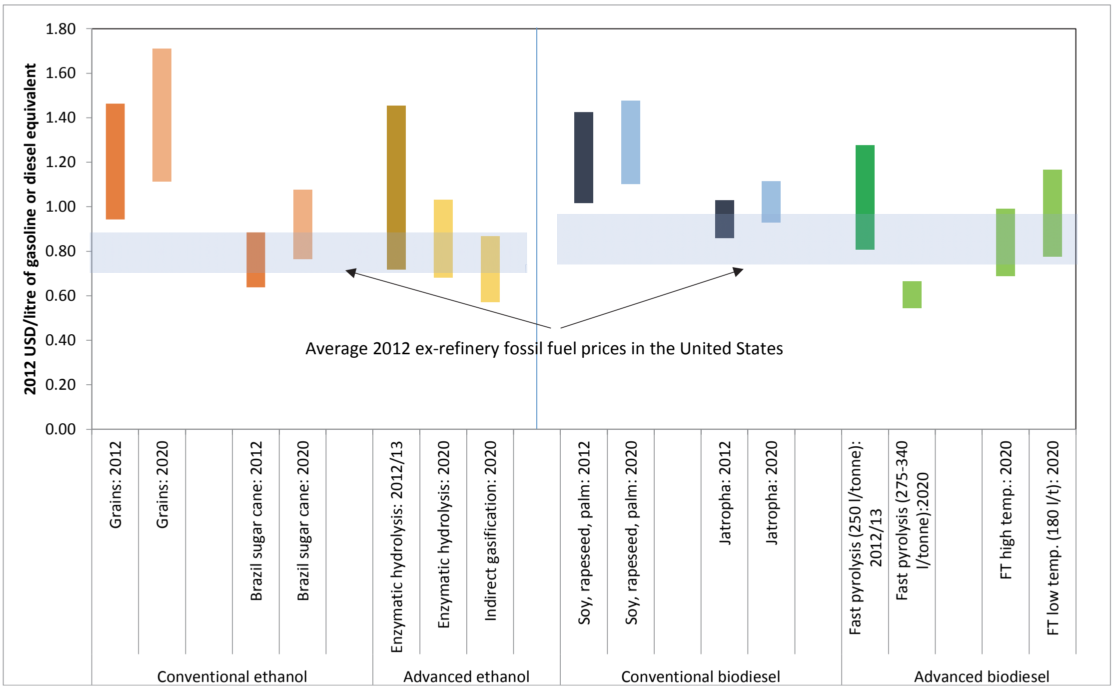

Figure ES.1: Summary of conventional and advanced biofuel production costs, 2012 and 2020

Advanced biofuels from lignocellulosic feedstocks are just beginning to be produced at first-of-a-kind plants at commercial production scales. The capital costs of these plants are, as would be expected, higher than for mature conventional plants. However, with around 15 plants planned to be online within the next few years, emerging cost data suggest a positive outlook. If current support policies can be enhanced and accelerated, advanced biofuels could become cost competitive with fossil fuels by 2020, assuming some of the technology pathways now being explored will prove to be reliable at commercial scales.

Policy support for advanced biofuels – from lignocellulosic feedstocks based on biomass, such as wood and agricultural residues – has stimulated the construction of the first commercial-scale advanced biofuels plants, notably in Europe and the United States. Although production is in its infancy, the outlook to 2020 and beyond for commercially viable advanced biofuels is increasingly positive.

Advanced biofuels offer some clear advantages over conventional biofuels derived from food crops. Advanced biofuel feedstocks do not have to be grown on pasture or arable land. They do not, therefore, compete with food supplies. Advanced biofuels also have the potential for much higher levels of production, very low greenhouse gas (GHG) emissions and reduced production-cost volatility.

With commercial-scale plants coming online, real cost data for advanced biofuels has started to emerge and will continue to grow. As competition spurs innovation, advanced biofuel developers are exploring various technology pathways to demonstrate the efficiency, reliability and potential for up-scaling plants. The capital costs for such first-of-a-kind plants, at relatively small commercial scales, are still relatively high. The key challenge remains to prove that the efficiency and reliability of production processes can be maintained while achieving continuous output at planned capacity levels.

Although advanced biofuels are only just at the early stage of commercialisation, and estimated production costs are still high, the cost reduction potential is good, and higher than for conventional biofuels. The key challenge is proving which technology pathways will work reliably at commercial production scales, with the significant technical and commercial risks these first-of-a-kind plants incur.

The first-of-a-kind commercial plants currently being deployed, sometimes at relatively small-scale, can require high investment costs, although some plants appear much cheaper than others. Advanced biofuel plants that recently became operational, are under construction or are planned to be online by 2015 have capital costs in the range USD 1.5 to USD 4.6 per litre per year of capacity (Figure ES.2).

Current production costs for ethanol via the enzymatic hydrolysis of lignocellulosic feedstocks may be in the range of USD 0.75/lge to USD 1.45/lge, based on the investment-cost data emerging for operating, under-construction and planned plants that should be online

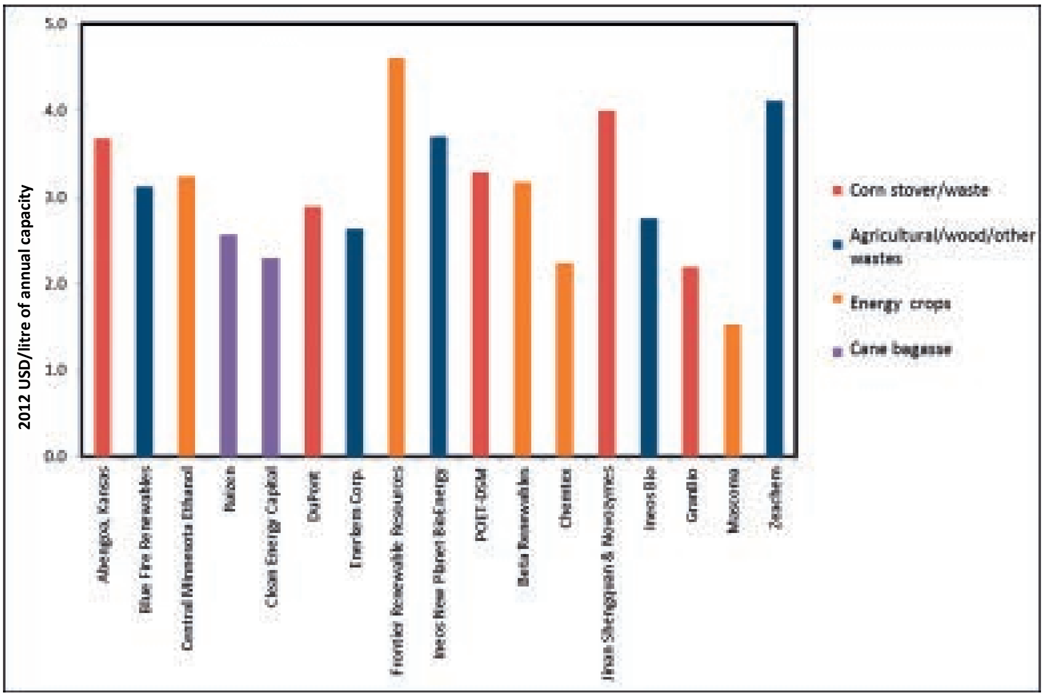

Figure ES.2: Capital costs for current or near future commercial-scale advanced ethanol plants

by 2015 (Figure ES.1). This cost estimate is tentative, as data gaps remain and the plants are yet to prove their reliability and capability to operate continuously and efficiently at design capacity. Solid data will start to emerge in the next 18 months and will be incorporated into future analysis by IRENA.

Advanced biodiesel productions costs could fall from between USD 0.8 to USD 1.3/litre of diesel equivalent to between USD 0.6 to USD 1.1/litre of diesel equivalent by 2020. However, these pathways are generally less advanced than those for ethanol.

Ongoing investment in research and development, funded by both public and private sources, is still essential to perfect different pathways and identify promising new production methods. However, the key immediate challenge is to gain experience with commercial-scale projects in each of the most promising pathways, now that commercialisation is beginning. This will require more risk sharing between public and private sector partners and enhanced deployment policies.

Biomethane is an oft overlooked transport fuel that can play an important part in the global road fuel mix. Biomethane produced from wastes (e.g. sewage, animal effluent, etc.) using the process of anaerobic digestion can provide low-cost renewable transport fuels today.

Biogas is composed mostly of methane and carbon dioxide produced from organic material. Like natural gas, it is a versatile fuel and can be used directly to generate electricity, to provide low- or high-temperature heat, or to power vehicles. For transportation, it can be upgraded, compressed and used in a dedicated or flex-fuel vehicle.

The key challenges for biogas are to grow the market and reduce costs. The use of biogas requires natural or biogas-based fuelling infrastructure and flex-fuel or dedicated natural/biogas vehicles.

Biomethane upgraded for use in vehicles can be produced for between USD 0.45/lge and USD 0.55/lge from wastes, but this range increases to USD 0.65-0.75/lge when maize silage is also purchased.

The commercialisation of mass-produced PHEVs and EVs is only just beginning, with a handful of vehicles available from selected manufacturers. The key challenge for electrifying transport is to reduce the cost of battery packs, from around USD 650/kilowatt hour (kWh) in 2012, and improve the performance of batteries. However, despite high incremental costs and the early stage of development, some PHEV and EV offerings are already close to competitiveness. Costs will have to continue to fall and ranges increase, but the outllook for 2020 is that EVs and PHEVs could be close to, or already will be, cost-competitive with conventional ICE vehicles powered by fossil fuels.

The average cost of gasoline saved with the first-of-a-kind mass production PHEVs now being offered for sale varies depending on incremental costs by manufacturer, retail gasoline prices, driving patterns and a range of other factors. However, with average retail gasoline prices

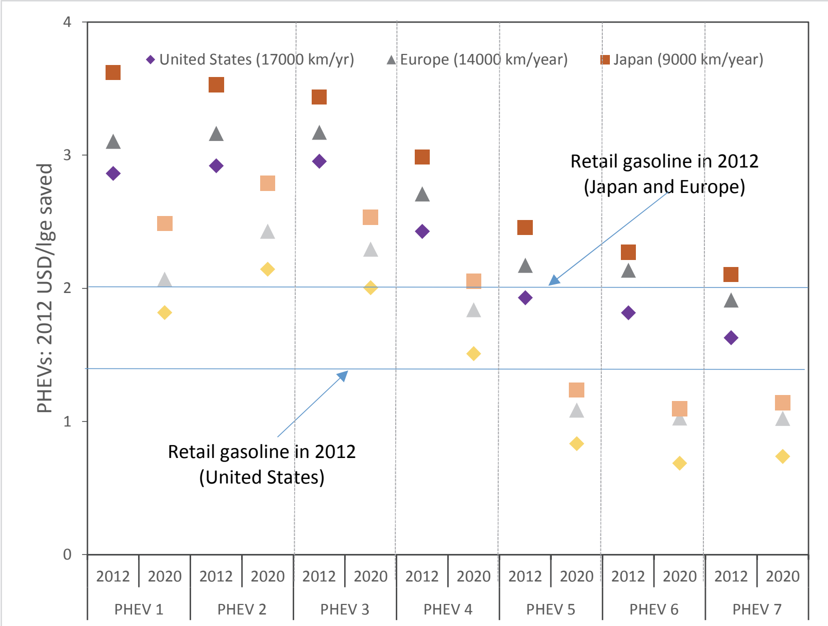

Figure ES.3: PHEV cost of gasoline saved, 2012 and 2020

of around USD 2/litre in 2012 in Europe and Japan, the cost of the gasoline saved is close to or less than the retail price for a number of PHEV offerings (Figure ES.3).

For EVs, the total cost of ownership, rather than cost of gasoline saved, is examined and compared to conventional ICE vehicles. Where the base ICE model is not the most fuel-efficient in its class, EVs look particularly attractive, even with the low production volumes of today's models. However, the economics are much more challenging when the base ICE model is more efficient (Figure ES.4). Improving battery performance will reduce costs and help increase the range of EVs, a key concern for many consumers.

Cost reductions for PHEV and EV batteries by 2020 could also be significant. The consensus from multiple sources puts future battery-pack costs in the range of USD 300-400/kWh for EVs by 2020, although more optimistic projections also exist. Assuming battery costs decline to USD 350/kWh for EVs and USD 500/kWh for PHEVs by 2020, then the cost of battery packs could fall by USD 5 500 per vehicle (for a 23 kWh pack) or more for larger batteries. At the same time, improvements in battery performance should see vehicle ranges increase.

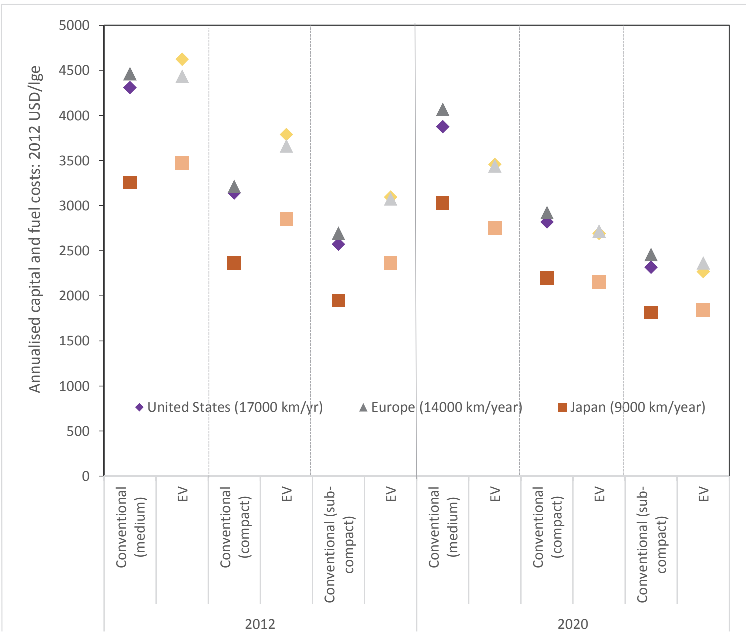

Figure ES.4: Total ownership costs for electric vehicles, 2012 and 2020

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1. INTRODUCTION

Road transport accounts for around a quarter of final energy consumption, and renewable energy technologies and fuels can help countries meet their policy goals for secure, reliable and affordable energy and reduced price volatility. They can also promote social and economic development. However, governments will find it difficult, if not impossible, to accurately assess which renewable options are best for their circumstances without reliable information on the costs and performance of renewable energy technologies available for road transport.

The aim of this report is to assist government decision-making by ensuring that decision makers have access to up-to-date and reliable information on the costs, benefits and relative performance of renewable energy technologies for road transport.

The use of renewable energy sources and technologies in the transport sector is not yet widespread. Renewables accounted for around 3% of road transport energy consumption in 2010, mostly conventional biofuels.[1] The range of renewable use for road transport by country varied from a low of zero in many countries to a high of 22% in Brazil (IEA, 2013a).

In the past, the adoption of renewables in transport has been hampered by a number of barriers. These include high costs (Brazil is an exception), misconceptions about the sustainability of biofuels and electric vehicles, and a lack of supporting policies in many countries.

However, the policy support that has been in place over the past decade and the gradual commercialisation of advanced biofuels (e.g. from biomass crops or waste) and electric vehicles mean there is a realistic prospect that renewable solutions could be competitive with incumbent technologies and fuels by 2020, as long as policy support for deployment is reinforced and expanded.

The accelerated deployment of these renewable technologies will lead to significant cost reductions due to progressive learning effects, research and development (R&D) advances and economies of scale in manufacturing. The increased production of both advanced biofuels and electric vehicles will help identify the technologies and processes appropriate for different markets, and which biofuel production processes work reliably and efficiently at commercial scale. The increasing size of the global market for renewable transportation technologies and fuels will help encourage a diversity of suppliers. It will also intensify the competitive pressures and beneficial effects this will have on innovation and costs.

In the seven sections that follow, this report outlines the principal findings of the latest analysis by IRENA of options available for road transport. These include a range of biofuel, biogas and electrification options. These results for renewable solutions for road transport are preliminary findings in what is a fast moving and dynamic situation for advanced biofuels and electrification of transport. The analysis will be updated in 2013 and integrated into an assessment of the cost of renewable solutions for air and sea transport to provide a more complete picture of the costs for the transport sector. This will also include additional data that is likely to emerge over the coming year from the first-of-a-kind advanced biofuels plants that are just starting up, and from more widespread distribution of plug-in hybrid electric vehicles (PHEVs) and pure electric vehicles (EVs).

The analysis summarised in this paper represents a static analysis of costs. Yet finding the optimal mix of renewable transport solutions in a country's transport energy mix requires dynamic modelling, not just of the transportation system, but of the energy system as a whole. Dynamic modelling takes into account the complexities of energy supply and use, as well as competing demands for bioenergy feedstocks (e.g. from power generation and heat production) and the increasing penetration of renewables in electricity generation. This modelling also needs to take into account the interplay between electricity supply, the grid and the role of PHEVs and EVs as sources of electricity demand, but also system flexibility when these vehicles batteries supply electricity to the grid. This presents challenges but also opportunities to attain higher levels of renewable electricity generation. An energy system approach is the only way to analyse these complex interactions between technologies, users and the system itself.

This analysis of the costs of renewable solutions for road transport – based on the latest available data and

1 Biofuel is a generic term that is typically applied to liquid fuels produced from agricultural (e.g. sugar cane, soya beans), forestry (e.g. black liquor, forestry residues) or other organic feedstocks (e.g. animal fats, algae). It can also be used as a term to include biogas and biomethane and, in future, biohydrogen from a variety of renewable sources.

information – supports the transparent assessment of the role different renewable solutions for road transport can play in decarbonising the transport sector, improving energy security and promoting economic growth.

1.1 Scope of the analysis and background of renewable solutions

This report examines the role of renewable solutions for road transport that are commercially available today, or that are likely to be commercialised by 2020 at reasonable cost. The analysis therefore focuses on conventional and advanced liquid biofuels, biomethane and electrification of transport using renewable power generation.

Liquid biofuels are not new. Their use goes back to the earliest era of the use of internal combustion engines in the 19th century, and Brazil has had significant shares of ethanol use for decades. However, the growth in biofuels production over the last 13 years has been driven by government policies. These aim to improve energy security and the diversity of fuel supplies, reduce oil and/or refined product imports, promote rural economic and social development and reduce greenhouse gas (GHG) emissions. This policy support began in Organisation for Economic Co-operation and Development (OECD) countries, but more and more developing countries have already enacted support policies or are developing them.

Biofuels can be split into two broad categories: conventional biofuels derived from food or animal feed crops[2] and advanced biofuels which use lignocellulosic feedstocks (Figure 1.1 and Figure 1.2). Since this report examines conventional and advanced biofuels that have already been commercialised or will be before 2020 at a reasonable cost, the analysis does not examine biohydrogen (via gasification and reforming or electrolysis using electricity from solar or wind) or biofuels from algae, which are at an earlier stage of research, development and demonstration (Figure 1.2).

Conventional bioethanol and biodiesel, also referred to as first-generation liquid biofuels, are produced from

2 For simplicity, biofuels produced from the wastes of the food or animal feed component of the crops are included in this category (e.g. used vegetable oil, yellow grease, etc). The reason for this is that their supply is essentially limited to the food and animal feed crop.

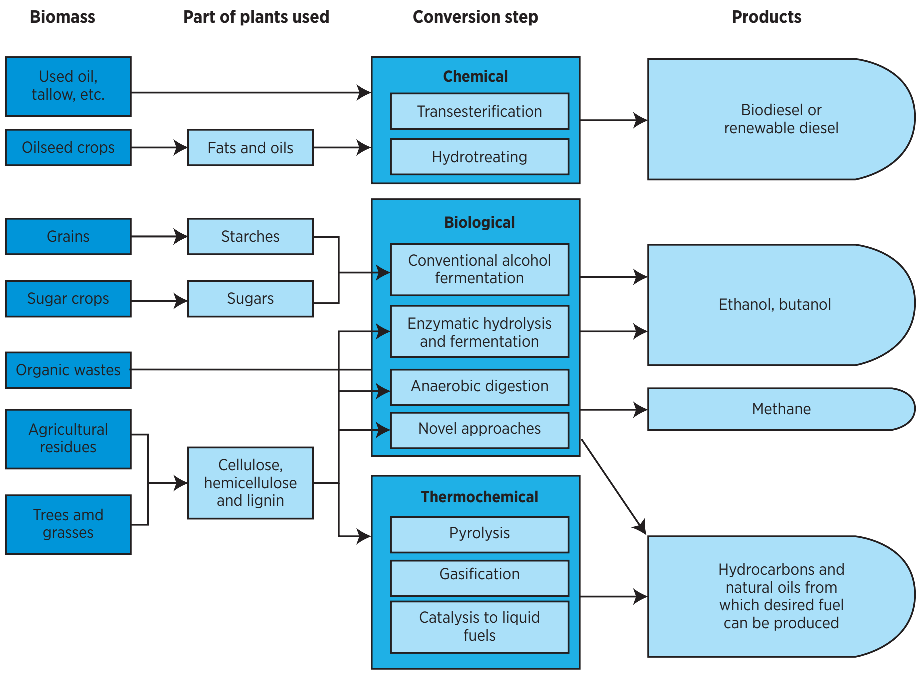
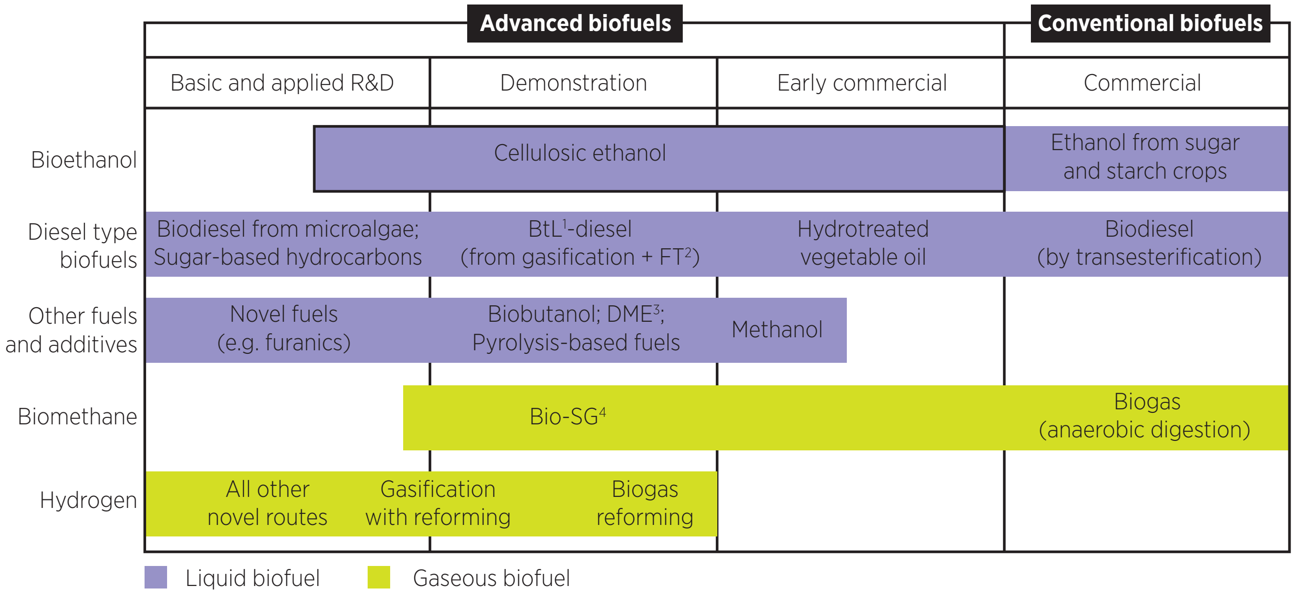


Figure 1.1: Biofuel pathways from feedstock to products

Source: Based on Schwaiger, 2011.



1. Biomass-to-liquids; 2. Fischer-Tropsch; 3. Dimethylether; 4. Bio-synthetic gas.

Figure 1.2: Maturity of different biofuel pathways

Source: Based on IEA, 2011.

mature processes at commercial scales. For bioethanol, the process comprises the conversion of sugar or starch derived from cereals/grains, sugarcane, sugarbeet, cassava, and others, via fermentation into alcohol and subsequent distillation to ethanol. For biodiesel, the feedstocks used include vegetable oil derived from oil palm, soybeans, rapeseed, Jatropha seeds and others, as well as waste cooking oil, animal fats and other sources of vegetable and animal fats and oils. The feedstock can either be converted into Fatty-Acid Methyl Ester (FAME), via transesterification of the raw material, or processed via hydrotreatment into a biodiesel with properties close to that of fossil diesel. Conventional biofuels also include methanol and butanol produced from starch or sugar through similar processes, and biomethane production from anaerobic digestion.

Advanced bioethanol and biodiesel, also referred to as second-generation biofuels, are produced using conversion technologies that are only just being commercialised or are still in the research and development (R&D), pilot or demonstration phase. This category includes bioethanol produced from the biochemical conversion of lignocellulosic feedstock such as wood, straw, bagasse and similar materials of biological origin into sugars followed by the fermentation into alcohol and distillation into ethanol. Methanol and butanol produced via similar processes are also included in this category, as well as any gasoline-type biofuels produced via thermochemical conversion of biomass (i.e. gasification followed by a fuel synthesis), or through processes using micro-organisms such as algae and bacteria.

Advanced biodiesel includes synthetic diesel or kerosene-type fuels derived via gasification and subsequent catalytic fuel synthesis or via pyrolysis and subsequent upgrading/refining. Also included in this category are algae-based fuels and diesel-type biofuels produced from sugar using microorganisms.

Virtually all biofuels produced today are conventional, whereas advanced biofuel production is entering the early phase of commercial deployment. A range of commercial-scale plants are online or coming online in the next three years (Bacovsky, 2013 and Brown and Brown, 2013).

Biofuels derived from food crops have net benefits in terms of emissions reductions and energy balance.[3]

3 The Global Bio-Energy Partnership (GBEP) has extensive analysis and recommendations of the sustainability issues surrounding biofuels.

However, they are extremely sensitive to food price movements and there is little opportunity for cost reduction, as the technology is relatively mature; only incremental improvements in process economics can be expected. Looking further into the future, the reliance on food crops will limit the potential contribution of these types of biofuels to total transport demand.

Advanced biofuels are still expensive today and only just being commercialised. However, they offer the potential for significantly lower and more stable feedstock costs and could meet a much larger proportion of transport demand, given that feedstocks can be sourced from a wide range of biomass sources. This is because advanced biofuels use lignocellulosic feedstocks from wastes/residues or from energy crops that do not have to be grown on pasture or arable land. The challenge is still to prove the efficiency, reliability and commercial attractiveness of the different pathways for advanced biofuels.

Biogas is composed mostly of methane and carbon dioxide produced from organic material. It can be upgraded and purified to become biomethane for use as a transport fuel in internal combustion engine (ICE) powered vehicles. It is compressed, to improve the energy density, and used in a dedicated biomethane vehicle or dual-fuel vehicle.

The key challenges for biogas are that to be used as a transport fuel, it requires natural gas or biomethane-based fuelling infrastructure and flex-fuel or dedicated natural/biomethane vehicles. Alternatively, existing vehicles can be converted to run on biogas, but at a cost and with a loss in storage space and range to accommodate the storage tank.

The two most promising routes for the production of biogas for transportation are anaerobic digestion (AD) of organic matter and the gasification of woody biomass to produce synthetic biogas. AD is commercially mature and is already used around the world to produce biogas from organic wastes (e.g. refuse, sewage and other effluents) and this is the option examined in this paper.

The use of electricity from renewable sources as an energy source for vehicles, either in PHEVs or EVs, is an important option to decarbonise the transport sector.[4] It also has significant co-benefits in terms of reducing local pollutant emissions and reducing the negative health impacts of local pollutant emissions from internal combustion engine powered vehicles.

4 Hybrid electric vehicles (HEV) combine a battery with an electric motor and an ICE. However, there is no external electricity source, as the battery is charged from the ICE or with regenerative breaking. These are therefore not in the scope of this report.

The key challenge is to improve the performance of the batteries used in PHEVs and EVs to provide greater range than today at lower costs. PHEVs combine an often downsized ICE with the capability for all-electric driving in charge depleting mode from a battery recharged from the grid. Depending on battery size and driving patterns, PHEVs can cover a majority of vehicle kilometres on electricity alone. Meanwhile, the retention of an ICE means that the total range of the vehicle on electricity and liquid fuels is comparable to today's ICE vehicles.

With EVs, the ICE is dispensed with and electricity from the battery provides all of the energy required for driving through one or more electric motors. The EVs battery is recharged from an electricity source (grid-connected or off-grid), from regenerative braking and potentially from integrated PV panels. The main advantages of EVs are that:

- they have zero local pollutant emissions;
- they are much quieter than a vehicle with an internal combustion engine (ICE); and
- their electric motors are much more efficient than an ICE and cheaper as well.

These advantages have to be offset by the early stage of vehicle battery technology development, with their low energy and power densities compared to liquid fuels, and relatively high costs. However, cost reduction potentials are good given that commercialisation of mass-produced PHEVs and EVs is only just beginning. An advantage of the electrification route is that the basic technology components are relatively mature, with the exception of batteries, while the existing experience with batteries from consumer products means that there are a range of potential battery suppliers and significant investment in innovation and R&D to develop battery technologies optimised for PHEVs and EVs.

1.2 Methodology and boundaries for the analysis

The foundations of an investment decision are made based on the costs of renewable fuels and technologies. This is critical to understanding the competitiveness of renewable energy options for transport.

Road transport costs can be measured in a number of different ways, with each approach providing its own particular insights. By setting clear boundaries and methodologies for its analysis, IRENA aims to ensure transparency in the methodology and assumptions used to make cost calculations. This minimises any confusion about the comparability of data and allows the debate to focus on the underlying assumptions.

Cost analysis can be very detailed, but for comparison purposes, the approach used here is a simplified one. This allows greater scrutiny of the underlying data and assumptions and improves transparency and confidence in the analysis. It also facilitates the comparison of costs by country or region for the same technologies in order to identify the key drivers in any differences.

This paper focuses on the cost of renewable solutions from the perspective of investors, whether they are a public or private company, individual or a community looking to invest in renewable options for transportation. The analysis excludes the impact of government incentives or subsidies, as well as any energy system-wide costs or cost reductions except where noted (e.g. additional electricity infrastructure for EVs). Furthermore, the analysis does not take into account CO_2 pricing or the benefits of renewables in reducing other externalities (e.g. reduced local air pollution or contamination of the natural environment). Similarly, there is no quantification of the benefits from renewables being insulated from volatile fossil fuel prices.

The analysis required to calculate the external costs of fossil fuel use from climate change and local pollutant emissions is important, but is beyond the scope of this report. The range of uncertainty surrounding estimates of external costs can also be a distraction from the underlying cost data, while local pollutant emission external costs obviously vary significantly regionally. However, it is clear that including these costs would improve the economics of the renewable options presented here.

The data used for the comparisons in this paper come from a variety of sources, such as governments, industry associations, business journals, manufacturers, project developers, consultancies and other private companies. Every effort has been made to ensure that these data are directly comparable and are used with the same system boundaries. Where this is not the case, the data have been corrected on a common basis using the best available data or assumptions.

It is important to note that, although this paper tries to examine costs, strictly speaking, the data available are usually prices. They are often not even true market average prices, but price indicators. The difference between costs and prices is determined by the amount above, or below, the normal[5] profit that would be seen in a competitive market.

5 The idea of "normal profits" is an economic concept where the level of profit results in a return on investment equal to the risk adjusted rate of return for the industry.

The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis in time, taking into consideration the time value of money. As a result, the weighted average cost of capital (WACC- often also referred to as the discount rate) used to evaluate the project has a critical impact on the cost of the option being examined.

All costs presented in this paper are in real 2012 USD; that is to say, after inflation has been taken into account unless otherwise stated.[6] A standard discount rate of 10% real (i.e. after adjusting for inflation) is used to discount all financial flows to a common basis in this report (unless explicitly noted that another value has been used). This assumption is consistent with all the previous costing analysis conducted by IRENA (IRENA, 2012a-e and IRENA, 2013).

Unlike power generation, where one relatively simple methodology was possible,[7] analysis of the transport sector requires several different methodologies to accurately reflect the very different technologies. The methodologies and boundaries used to assess the costs of biofuels and biogas, PHEVs and EVs are described below.

Biofuels and biogas

The analysis of biofuels and biogas shares a common methodology and is based on a DCF analysis of the capital, operations, maintenance and fuel costs of producing biofuels and biogas. This methodology is similar to that used for power generation, but requires additional data about the process technology to determine the yields of biogas and biofuels from a given feedstock. Different processes and feedstocks will therefore have quite different final costs for the feedstock component.

The formula used for calculating the cost of biofuels and biogas is:

Biofuel or biogas cost (per litre of gasoline equivalent)

$$= \frac{\sum_{t=1}^{n} \frac{(I_t + M_t + F_t - CP_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(E_t)}{(1+r)^t}}$$

6 An analysis based on nominal values with specific inflation assumptions for each of the cost components is beyond the scope of this analysis. Project developers will build their own specific cashflow models to identify the profitability of a project from their perspective.

7 See IRENAs most recent analysis of power generation *Renewable Power Generation Costs in 2012: An Overview* for a discussion of the methodology used. This is available as a free download at www.irena.org/publications.

Where:

- I_t = investment expenditures in the year t for the production plant;
- M_t = operations and maintenance expenditures in the year t;
- F_t = Net feedstock expenditures in the year t (based on process yields and feedstock prices, less revenues from co-products or gate fees for waste);
- CP_t = The value of non-feedstock co-products (e.g. surplus electricity sold to the grid);
- E_t = energy produced in the year t (based on plant capacity, availability and yields from feedstock);
- r = discount rate; and
- n = economic life of the system.

Given liquid biofuels and biogas are direct competitors with liquid fossil fuels, the costs are presented per litre of gasoline equivalent for ethanol and biogas, and per litre of diesel equivalent for biodiesel. This adjustment is necessary because the volumetric energy content of ethanol is around two-thirds of that of fossil fuel-based gasoline. This needs to be taken into account in order to analyse gasoline and ethanol on a comparable basis. The energy content of a litre of biodiesel is around 90–94% of conventional fossil fuel diesel. The analysis for biogas is based on a normalised cubic metre of gas, which is the volume of gas for a normalised temperature and pressure of 0°C and 1.01325 bar A respectively given that this is the standard unit for the industry. However, for the final cost of biogas the data is also presented per litre of gasoline equivalent to provide a direct comparison with the incumbent fossil fuel option.

It is important to note that in this equation for biofuels and biogas plants the feedstock costs are net of the value of co-products arising from the feedstock. This includes, for instance, dried distiller grain for grain-based liquid biofuels and any gate fees for waste disposal or revenues from fertiliser production at biogas plants. Co-products not associated with the feedstock, such as surplus electricity exported to the grid, are treated separately.

For both biofuels and biogas, the system boundary for which costs are examined are ex-plant. The rationale for this is that the transportation and distribution costs for liquid biofuels and biogas are very similar to the equivalent liquid fossil fuels and natural gas.

Plug-in hybrids and electric vehicles

PHEVs and EVs require separate methodologies. For PHEVs the cost of gasoline/diesel saved is considered. This can then be directly compared to the retail cost of gasoline or diesel to determine the competiveness of the PHEV compared to an equivalent vehicle equipped with an internal combustion engine. The formula for PHEVs is:

Cost of gasoline/diesel saved =

$$= \frac{\sum_{t=1}^{n} \frac{(I_t + EC_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(FS_t)}{(1+r)^t}}$$

Where:

- I_t = additional investment per vehicle (over a conventional vehicle) in the year t;
- EC_t = electricity cost in the year t (as a function of km travelled using electricity and the electricity consumption per km);
- FS_t = fuel saved in litres as a result of electric km driven in the year t (based on fuel efficiency of a comparable conventional vehicle);
- r = discount rate; and
- n = economic life of the vehicle.

For EVs the annualised total cost of ownership for the vehicle including purchase price and electricity costs is examined and then compared to the annualised total ownership costs for an equivalent conventional vehicle. The reason for this approach is that it doesn't make sense to talk about the cost of gasoline saved when there is no internal combustion engine and that most EVs available today are purpose-designed vehicles and a direct comparison with an identical equivalent ICE vehicle is often not possible.

As far as EVs and PHEVs are concerned, this report discusses the costs of electrical charging infrastructure, but does not attempt to fully integrate this into the cost analysis. The wide range of possible infrastructure deployment strategies and their varying costs are beyond the scope of this report. Infrastructure deployment patterns and their costs, given their complexity, merit their own analysis.

2. ENERGY CONSUMPTION FOR TRANSPORT

In 2010, land, air and sea transport together accounted for around 26% of total final energy consumption, down from around 27% in 2000.[8] The energy consumption for transport increased by 1.9% per year between 2000 and 2010, increasing from 79.5 EJ to 96.3 EJ in 2010 (Figure 2.1) (IEA, 2013a).

Energy consumption in the transport sector is dominated by road transport, which accounted for 76% of total transport demand in 2010. Aviation accounted for 11% of energy consumption in the transport sector in 2010, with 62% of this consumption coming from international aviation, up from 52% in 2000. Sea transport also accounted for around 11% of total transport consumption in 2010, up from 10% in 2000.

8 The statistical convention is that the energy used for pipelines is also included under transport. However, because this does not relate to the conveyance of people or goods from one point to another it is excluded from the analysis in this report.

2.1 Road transport energy consumption

Land transport energy consumption is dominated by road transport, which accounts for 76% of energy consumed and is the focus of this report. Oil products dominate the road transport sector, although their share has fallen from 99% in 2000 to 95% in 2010. In 2000, 59 EJ of oil was consumed for road transport globally, compared to 0.4 EJ of biofuels and biogas, 0.1 EJ of natural gas and virtually no electricity.

By 2010, oil consumption globally for road transport had grown to 70 EJ, but biofuels had risen almost sixfold to 2.4 EJ and accounted for 3.3% of road transport energy consumption. Natural gas consumption grew sevenfold between 2000 and 2010 to reach 0.9 EJ in 2010. Electricity consumption for road transport actually fell between 2000 and 2010 (IEA, 2013a).

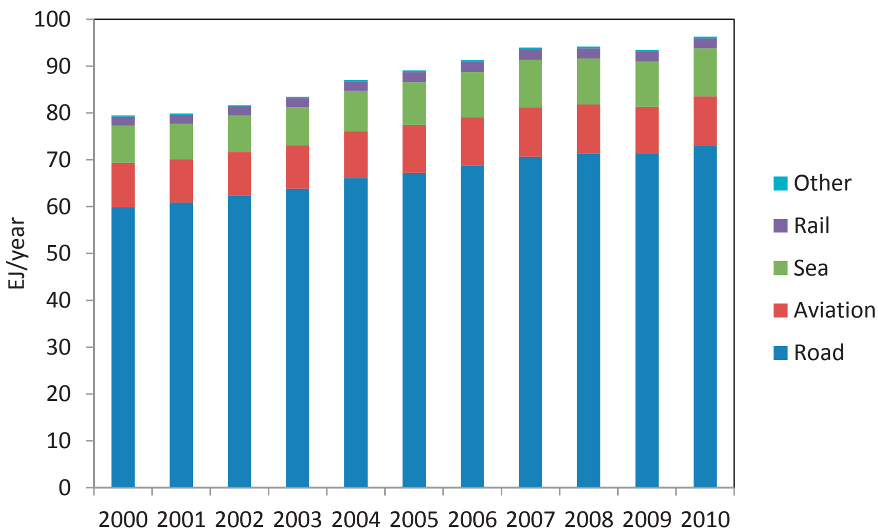


Figure 2.1: Transport energy consumption by sector, 2000 to 2010

Source: IEA, 2013a.

Figure 2.2: Energy consumption for road transport by fuel, 2000 to 2010

Source: IEA, 2013a.

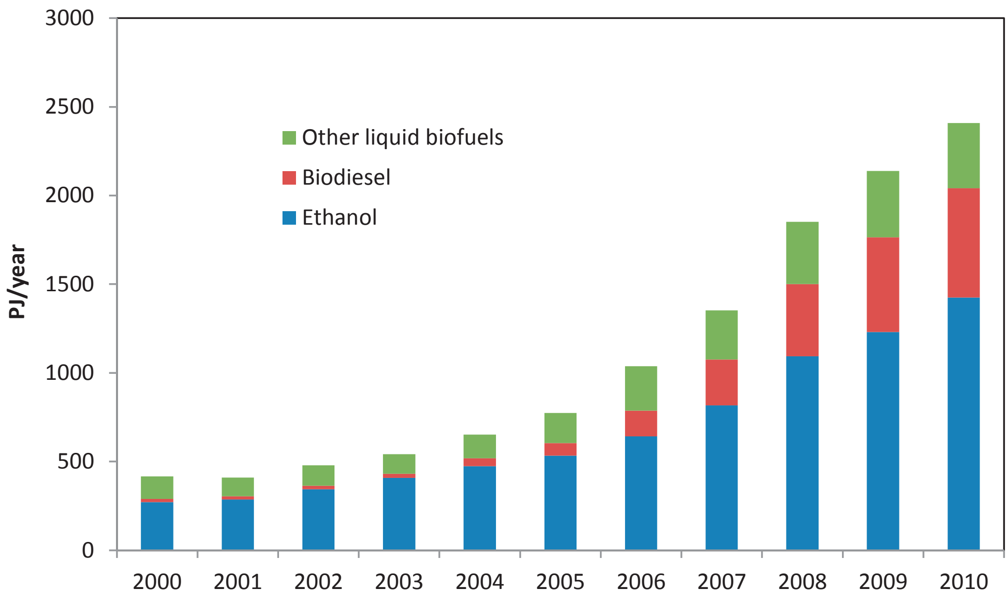


Figure 2.3: Biofuel consumption for transport by fuel, 2000 to 2010

Source: IEA, 2013a.

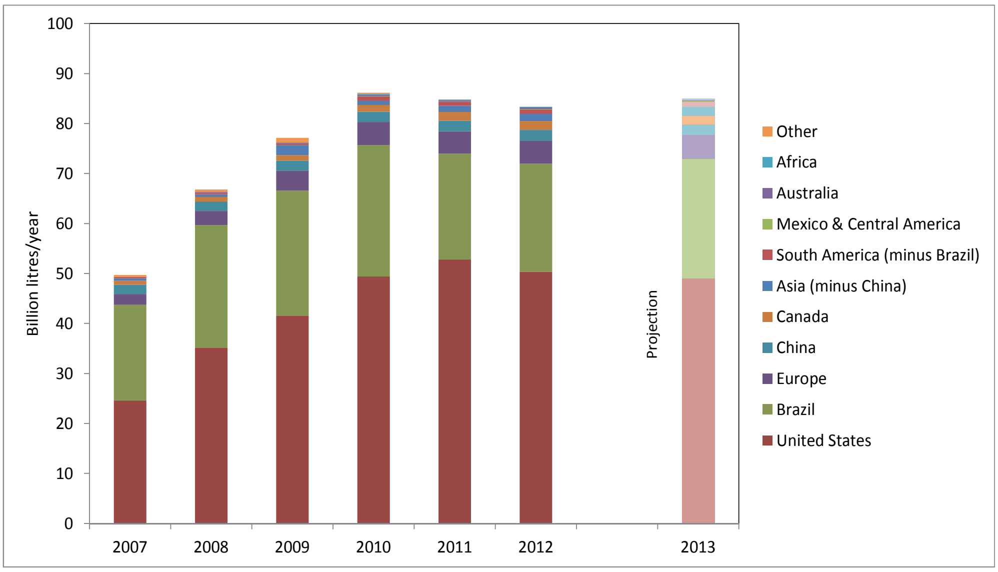


Figure 2.4. Global ethanol production by country and region, 2007 to 2012

Note: *Data for 2013 are projections of full year output. One billion litres of ethanol contains around 21 PJ of energy.*
Sources: F.O. Licht and Renewable Fuels Association, 2013.

Total consumption of biofuels – ethanol, biodiesel, other liquid biofuels and biogas – for road transport grew from around 417 PJ (0.42 EJ) in 2000 to 2 410 PJ (2.41 EJ) in 2010.[9] Ethanol consumption grew from 272 PJ in 2000 to 1 426 PJ in 2010, a growth rate of 18% per year. Biodiesel growth was even more impressive, from just 18 PJ in 2000 to 616 PJ in 2010, a rate of 42% per year. Other liquid biofuels also increased, but at a more modest rate of 11% per year from 126 PJ in 2000 to 368 PJ in 2010 (Figure 2.3).

Recent data for biofuels production suggest that consumption may have increased slightly from 2010 levels, given that production has grown from 1.83 million barrels per day (mb/d) in 2010 to 1.87 mb/d in 2011 and 2012. The outlook for 2013 is for total liquid biofuels production to grow to 2.02 mb/d (IEA, 2013b).

2.2 Conventional biofuel production trends

The largest producers of ethanol are the United States and Brazil (Figure 2.4). Estimates indicate the United States produced 61% of the global total in 2012, with Brazil producing just over a quarter. Europe, China and Canada are other major producers. However, Europe, the third largest producer, only accounts for around 5% of global production. Production of ethanol in the United States is based almost exclusively on corn, while sugar cane is used in Brazil. Global ethanol production declined in 2011 and in 2012 from record production levels in 2010. In 2011, production growth slowed in the United States as corn prices climbed, while high sugar prices contributed to a contraction in Brazilian output of around one fifth. In 2012, Brazilian ethanol production remained flat compared to 2011, but production declined by around 5% in the United States. Projections for 2013 suggest a global increase in production (F.O. Licht, 2013), as production increases in Brazil are expected to offset a contraction of around 3% in the United States compared to 2012.

Global biodiesel production grew by 29 times its original size between 2000 and 2012 (Figure 2.5).[10] Europe, where biodiesel production has grown from very low levels in 2000 to 10.4 billion litres in 2012 (IEA, 2013a and F.O. Licht 2013), has led the global increase. The rapid growth in biodiesel has been driven in part by the

9 The different types of biofuels are defined in Section One.

10 In this section, biodiesel production includes hydrogenated vegetable oil (HVO) that is produced in Europe the United States and Singapore. Total production was around 2.7 billion litress in 2012.

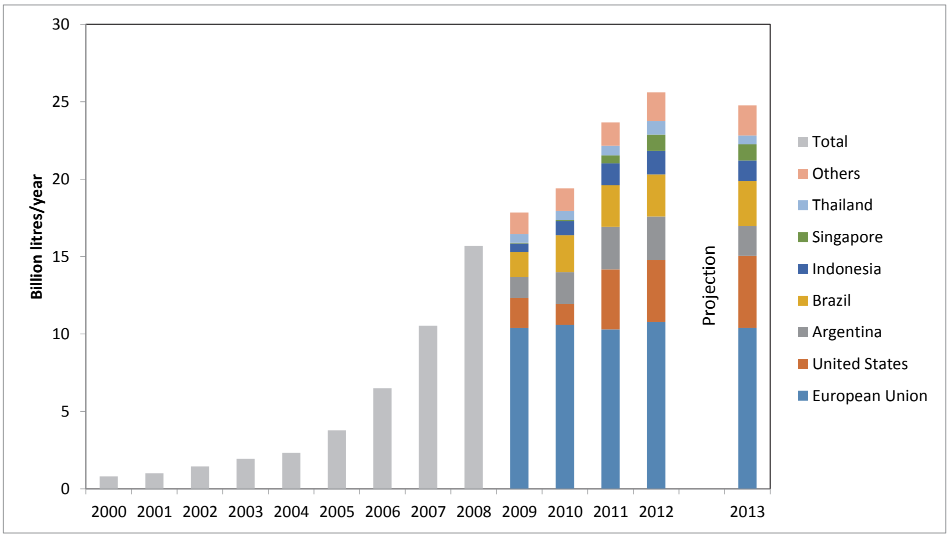


Figure 2.5: Global biodiesel production, 2000 to 2012

Sources: IEA, 2013 and F.O. Licht, 2013.

biofuels mandate.[11] The United States is the second largest biodiesel producer with output of around 4 billion litres in 2012. Argentina is the third largest producer of biodiesel with production of 2.8 billion litres in 2012. Brazil is the fourth largest producer. Biodiesel production began in 2005 and rose to just over 2.7 billion litres in 2012. Indonesia is the next largest producer with output of 1.5 billion litres in 2012.

Global biodiesel production grew by 7% in 2012, with most of this growth occurring outside of Europe, the United States, Brazil and Argentina. FAME biodiesel production declined in Europe in 2012 to around 9 billion litres leaving significant underutilised production capacity. However, growth in hydrogenated vegetable oil production to 1.5 billion litres offset this decline and resulted in net growth of around 0.35 billion litres (F.O. Licht, 2013 and European Biodiesel Board, 2013).

Biodiesel production in North America fell by at least a quarter in 2010 compared to 2009 after the biodiesel tax credit expired (F.O. Licht, 2013 and U.S. EIA, 2012). However, the retrospective reinstatement of the credit at the end of 2010 saw this decline dramatically reversed in 2011, and production increased to around 3.8 billion litres in 2011 and to 4 billion litres in 2012 (F.O. Licht, 2013). Production in 2012 was therefore three times higher than in 2010.

11 European production also helps to reduce diesel imports, as Europe has a structural deficit in its refining capacity for diesel and a surplus for gasoline.

2.3 Advanced biofuel production trends

With ethanol production of around 83 billion litres and biodiesel production of around 26 billion litres in 2012, conventional biofuels dominate total biofuels production. By the beginning of 2013, global advanced biofuel production capacity had reached an estimated 230 million litres/year (Ml/year) (F.O. Licht, 2013). Advanced biofuel production of 76 000 litres was recorded in the United States in 2012 (U.S. EIA, 2013a), which was the location for almost 120 million litres of the global advanced biofuels capacity. In the United States, the KiOR company's fast pyrolysis biomass-to-liquids first commercial facility has a production capacity of around 50 Ml/year. Ineos' Florida facility has production capacity of around 30 Ml/year, with the balance of the 120 million litre/year in total coming from several smaller plants. In Europe, around 70 Ml/year of production capacity is divided between Borregrad's cellulosic ethanol plant (20 Ml/year) in Norway and Beta Renewables Italian plant (50 Ml/year). Additional cellulosic capacity is also onstream in Canada and China. China could become a significant player in the short-to medium-term, with as much as 90 Ml/year of production capacity to be added in 2013 (F.O. Licht, 2013).

By 2015 global advanced cellulosic biofuels capacity could reach 1.3 billion litres/year (F.O. Licht, 2013), with around two thirds of this capacity located in the United States. Although this represents dramatic growth from today's level, it will still mean that advanced biofuels contribute just 1-2% of total biofuels production in 2015 and a smaller contribution to total energy demand in the road transport sector.

3. THE COST OF RENEWABLE SOLUTIONS FOR ROAD TRANSPORT: AN OVERVIEW

Conventional biofuels derived from food or animal feed crops dominate the renewable contribution to road transport demand today. Conventional biofuels, both ethanol and biodiesel, have seen their costs increase as food prices have risen, particularly since 2005. The outlook to 2020 is for little change in food prices, and hence in feedstock costs for conventional biofuels.

Although the current climate for renewables in transport is challenging, the analysis in this report highlights that the outlook for the future is increasingly positive. If support policies are expanded and enhanced, advanced biofuel technologies to produce biodiesel and ethanol could be competitive with fossil fuels by 2020, while PHEVs and EVs could provide mobility at comparable overall costs to internal combustion engine (ICE) powered vehicles by 2020 in an increasing range of market segments. Biomethane from biogas expands the renewable options for transport and when produced from wastes can provide a very competitive transport fuel even today.

The key challenges for advanced biofuels, biomethane and PHEVs and EVs are to reduce their costs and improve their performance in order to achieve competitiveness with fossil fuels. The opportunities for cost reductions are good, particularly for advanced biofuels and PHEVs and EVs, which are only just beginning to be commercialised at scale. The data emerging from these first commercial advanced biofuel projects and EV offerings from manufacturers are very encouraging, and the cost reductions from R&D efforts, "learning by doing", larger economies of scale and a wider range of technology suppliers could be significant by 2020. However, to unlock this potential will require the expansion of existing support policies and their enhancement in the coming years, to 2020 and beyond.

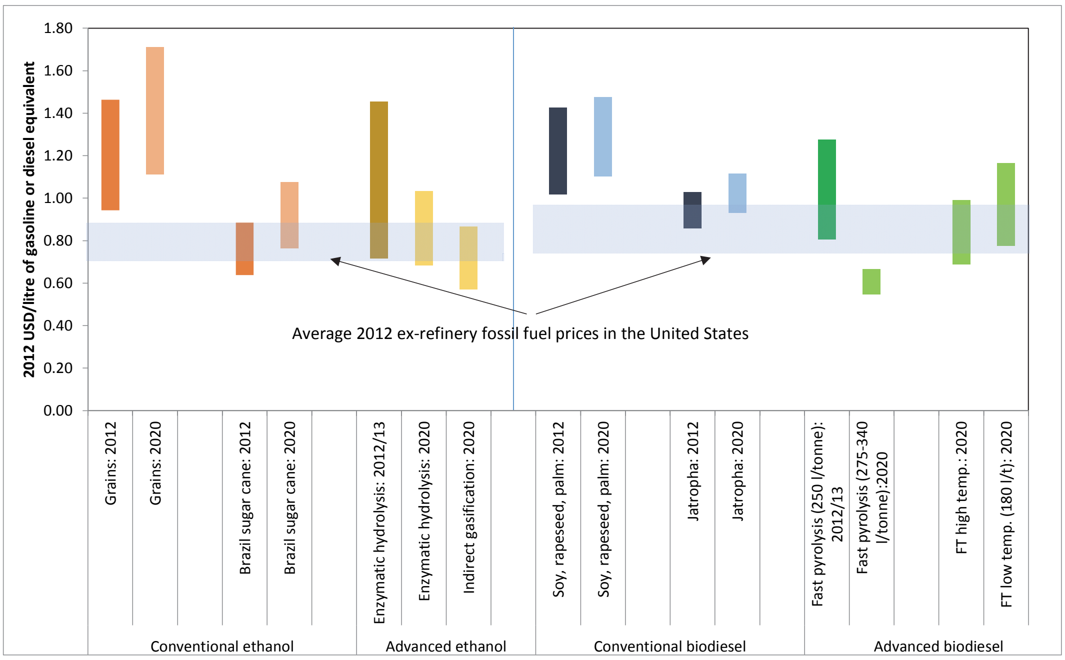


Figure 3.1: Summary of conventional and advanced biofuel production costs, 2012 and 2020

Sources: See sections Four, Five and Six.

The road ahead for renewables in transport is challenging, but the positive signs from early commercialisation mean that the world may be witnessing the beginning of an era of competitive renewable options for road transport across a range of modes and vehicle technologies.

3.1 The current costs of liquid biofuels and biomethane and the outlook to 2020

The production costs of conventional liquid biofuels derived from food or animal feed crops are dominated by the feedstock cost, both for ethanol and biodiesel (Figure 3.1). As a result, the cost of conventional biofuels from food-based feedstocks is very sensitive to changes in the prices of the feedstocks used. For ethanol, feedstock costs over the past three years have typically accounted for 60-80% of the total production cost, while high feedstock costs in 2012 mean that has averaged around 80% for corn ethanol in the United States.[12] For biodiesel the situation is even more pronounced, with feedstock costs making up almost 90% of production costs. For biofuels using food-based feedstocks, this means production costs will be volatile, as global market prices for these foodstuffs experience significant variations over time due to changes in demand and supply. If income received for these conventional biofuels do not also move with these input costs, then the profitability and economic viability of their production may be adversely affected.

In 2012, conventional ethanol production from corn in the United States was estimated to have had production costs of between USD 0.94 to USD 1.0/litre of gasoline equivalent (lge), while Brazilian sugar cane ethanol was estimated to have had production costs of between USD 0.69 to USD 0.88/lge. This compares to average refinery wholesale prices in the United States of between USD 0.72 and USD 0.84/litre in 2012.[13]

Conventional biodiesel production costs from soy and rapeseed oils in 2012 were estimated to have averaged around USD 1.3/litre of diesel equivalent. Biodiesel produced from palm oil in Malaysia and Indonesia was estimated to have lower production costs, of around USD 1/litre of diesel.

12 The United States Agriculture Department forecasts that corn prices in 2013/2014 will average 30% less than in 2012. This would mean feedstock costs will be around 75% of total production costs (USDA, 2013)

13 This monthly average data data is from the U.S. EIA and provides a price benchmark against which ethanol producers' production costs can be compared.

The initial deployment of advanced cellulosic biofuels is hampered by many of the same problems that face any new technology. Capital costs are currently two to six times higher than for corn ethanol plants and the production processes are only now being proven at commercial scale. This means there is currently no certainty or clarity over what pathways represent the most promising development options. However, data is beginning to emerge from the first operational plants, while some data for projects under construction or planned to be online by 2015 is also becoming available. The key challenge remains to prove the efficiency and reliability of these processes can be maintained while achieving continuous production at planned capacity levels.

One of the key advantages of advanced biofuels is that, in contrast to conventional biofuels, feedstock costs for advanced biofuels that use cellulosic feedstocks are expected to range between 30-45% of total production costs in the long term. Advanced biofuels will therefore be less sensitive to variations in feedstock prices. They will also be able to secure biomass feedstocks in long-term contracts that also significantly reduce the feedstock price volatility compared to conventional food-based feedstocks. However, the high capital costs for these early commercial-scale cellulosic biofuels plants are a significant barrier to their deployment. This is also true of the uncertainties concerning the ability of different process pathways to reliably, continuously and efficiently convert cellulosic feedstocks into biofuels.

Current production costs for ethanol via the enzymatic hydrolysis of lignocellulosic feedstocks may be in the range of USD 0.75 to USD 1.45/lge, based on the investment cost data for operating, under-construction and planned plants that should be online by 2015. These data are tentative, as the processes are yet to prove those plants' reliability and capability to and operate continuously and efficiently at design capacity. It also assumes "other" operating costs are a quarter higher than the long-term optimised level (Humbird, 2011) and that feedstock costs are USD 65/dry tonne for agricultural and forestry residues or for energy crops, while municipal solid wastes and sugar cane bagasse costs are half to a quarter of this. These assumptions are necessary, as the actual data on the other operating costs and feedstock costs are not yet clear. The cost estimates will remain indicative until further data is available.

Conventional liquid biofuel production costs are projected to rise to 2020 as the result of modest increases in feedstock prices. Although food price increases are expected to slow compared to that experienced since 2005, the OECD-FAO outlook for the agricultural sector to 2020 projects increases in corn prices of around 1% between 2012 and 2020, 11% for global wheat prices and 25% in the cost of sugar cane in Brazil (OECD-FAO,

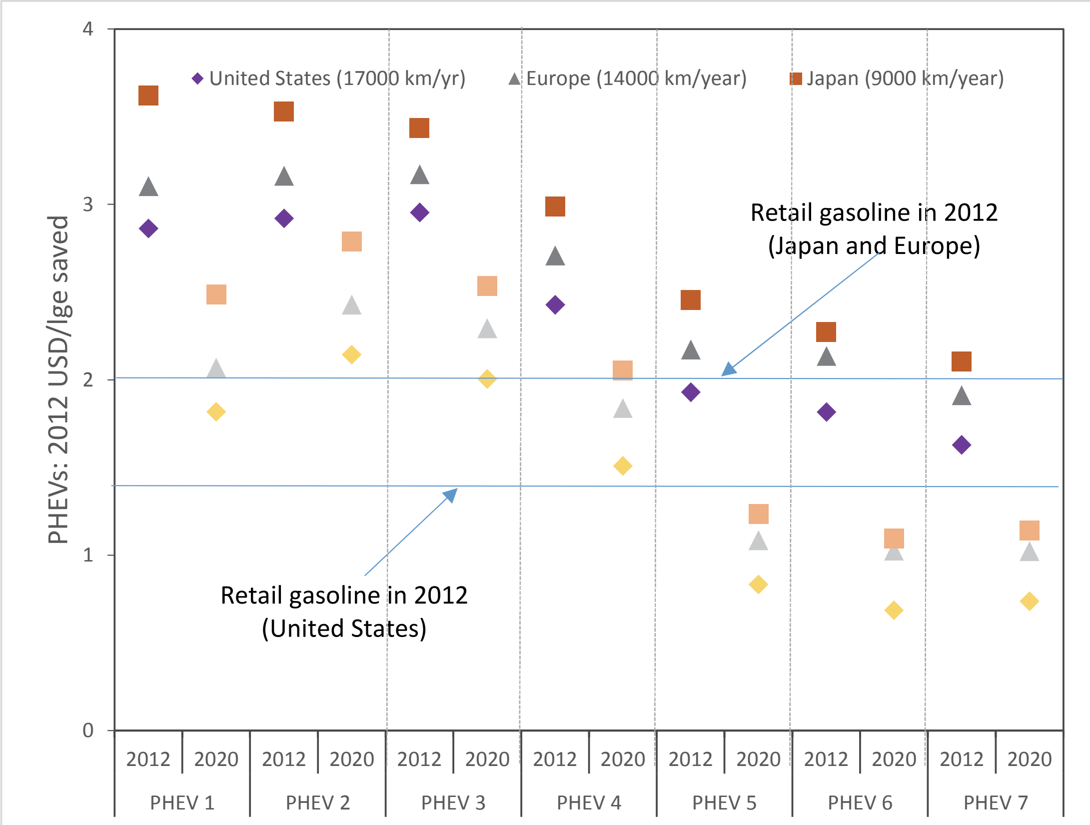


Figure 3.2: Cost of gasoline saved for PHEVs, 2012 and 2020

Sources: sections Seven and Eight.

2012). At the same time, the OECD-FAO outlook projects vegetable oil prices to increase by around 10%.

This could see grain-based conventional biofuel production costs increase by between 6% and 9% compared to 2012 levels, while production costs for ethanol from sugar cane in Brazil could increase by between 20% and 22% between 2012 and 2020. The production costs of biodiesel from vegetable oils may increase by around 8% under these assumptions by 2020.

Biogas production using digesters is a relatively simple and mature technology, with little opportunity for cost reductions. Current production costs for biomethane vary depending on the feedstock, but range from a low of about USD 0.45/lge for wastes to as much as USD 0.93/lge for small-scale systems purchasing maize silage.

However, the upgrading process – whereby inert components such as CO_2 and sometimes also N_2 are removed for increased energy density and making the biomethane ready for injection into the gas network or for use in vehicles – is an area where relatively small-scale applications have modest deployment numbers. Accelerated deployment and increasing the scale of individual production plants, would result in a significantly larger market and better economies of scale for manufacturers. This might also allow increased process integration and "off the shelf" solutions with lower project costs (Nielsen and Oleskowicz-Popiel, 2008). However, even assuming a 10% to 20% cost reduction for upgrading units by 2020 would only reduce biomethane production costs for vehicles by between 1% and 5% in 2020.

3.2 The current costs of PHEVs and EVs and the outlook to 2020

The current challenge for PHEVs and EVs is their high incremental costs and relatively low range compared to conventional ICE vehicles for EVs. However, they are just at the beginning of their commercialisation and the data emerging on their costs is encouraging.

The average cost of gasoline saved by the first-of-a-kind mass production PHEVs now being offered for sale taking into account the amortised additional capital cost and additional electricity expenses varies depending on the incremental vehicle costs, electricity and gasoline prices, and the fuel efficiency of the incumbent technology.

With average retail gasoline prices of around USD 2/litre in 2012 in Europe and Japan, the cost of the gasoline saved is close or less than the retail price for the PHEV offerings of Ford, Honda and Chevrolet compared to a comparable non-PHEV model from these manufacturer's (Figure 3.2). However, these results are quite sensitive to driving patterns and average annual vehicle travel patterns.

The challenge facing manufacturer's is that the base model against which PHEVs are compared is usually already relatively fuel efficient, resulting in the incremental costs being apportioned over relatively low fuel savings.

The average annual cost of ownership for EVs currently on the market in the United States, Europe, Japan, China and India varies significantly depending on the vehicle. Where a direct comparison with an ICE-powered vehicle is possible, the results are similar to the trend for PHEVs. Where the base model is not the most fuel efficient in its class, EVs look particularly attractive, even with today's low-production volume models. However, where the base-model is relatively fuel efficient the additional costs of the EV aren't recovered within the 160 000 km assumed for this economic comparison.

However, cost reductions for PHEV and EV batteries by 2020 could be significant. The consensus from multiple sources puts future battery pack costs at between USD 300 and USD 400/kWh for EVs by 2020, although more optimistic projections also exist.[14] An order of magnitude of the reduction in incremental costs if battery costs decline to USD 350/kWh for EV's and USD 500/kWh for PHEVs can be seen for the Ford Focus Electric's 23 kWh battery pack, which would be reduced in price by around USD 5 500. At the same time, improvements in battery performance should see the overall life of batteries increase from the current manufacturer's guarantees of around 160 000 km.

The total cost of ownership for EVs in 2020 assuming USD 350/kWh, extended life to 200 000 km, and no change in oil prices in real terms to consumers[15] results in electric vehicles becoming significantly more competitive by 2020 (Figure 3.3). The total annualised cost of ownership taking into account the vehicle cost (over a 200 000 km life) and fuel costs would be reduced by between one-fifth and a half depending on the vehicle compared to average battery pack prices in 2012 and a life of 160 000 km. Compared to the cost of ownership for an equivalent ICE vehicle, the total annualised cost of ownership in 2020 would be lower than for the equivalent ICE vehicle by between 2% and 13% (for the three models where direct equivalents are available) per year depending on the region and annual driving distances.

14 McKinsey projects EV battery packs could decline to as little as USD 200/kWh in 2020 (McKinsey, 2012). It is important to note that PHEV battery packs will be perhaps two-thirds to twice as expensive. See sections Seven and Eight.

15 The U.S. EIA's latest Annual Energy Outlook projects that crude oil prices will be little changed from 2011/2012 prices by 2020 under their Reference Scenario (U.S. EIA, 2013).

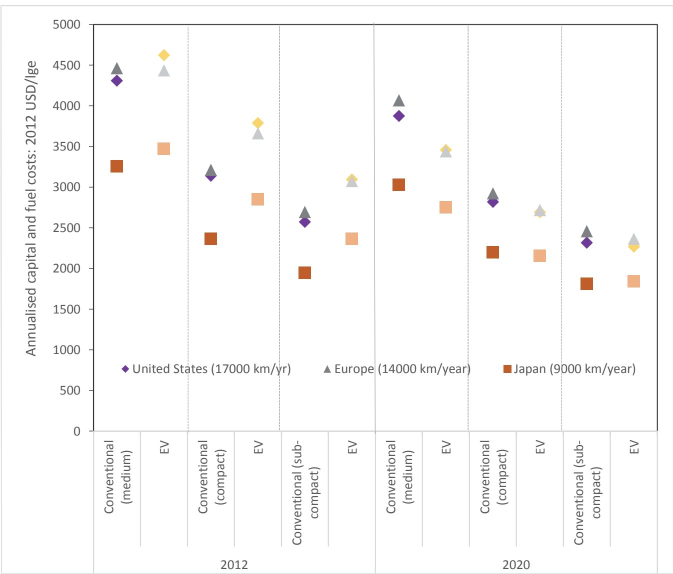


Figure 3.3: Total ownership costs for electric vehicles, 2012 and 2020

4. BIOETHANOL

4.1 Conventional bioethanol production pathways

Bioethanol produced from sugar cane, corn, sugar beet, wheat and other crops with high sugar or starch contents is the most common biofuel produced today. The production process is well understood and commercially deployed around the world at small- and large-scale. The liquid biofuels can then be blended with gasoline in a variety of proportions and can be used by conventional or flex-fuel vehicles (Box 4.1).

The production of bioethanol from crops high in sugar or starch is often referred to as a biological conversion route. This is because a biological process is used to convert the sugar or starch into ethanol. Depending on the feedstock, the main components that need to be extracted are sucrose or starch. For sugar cane or sugar beet crops, the sucrose is first mechanically pressed from the raw feedstock that has been heated (milling). It is then fractionated, after which the extracted sucrose is metabolised through yeast cells fermenting the hexose. The ethanol itself is then recovered through distillation (Figure 4.1).

In contrast, starch crops must first be hydrolysed into glucose and only after this process can the yeast cells convert the carbohydrates into ethanol. The process for starchy crops starts with a similar pre-treatment process that consists of milling the grains of corn, wheat or barley, followed by liquefaction and fractionation. At this point an acidic or enzymatic hydrolysis process is required, unlike for sugar cane ethanol, that will yield hexose that can then be sent to fermentation (Figure 4.2). This process is highly efficient, although more energy-intensive than the sucrose-based route.

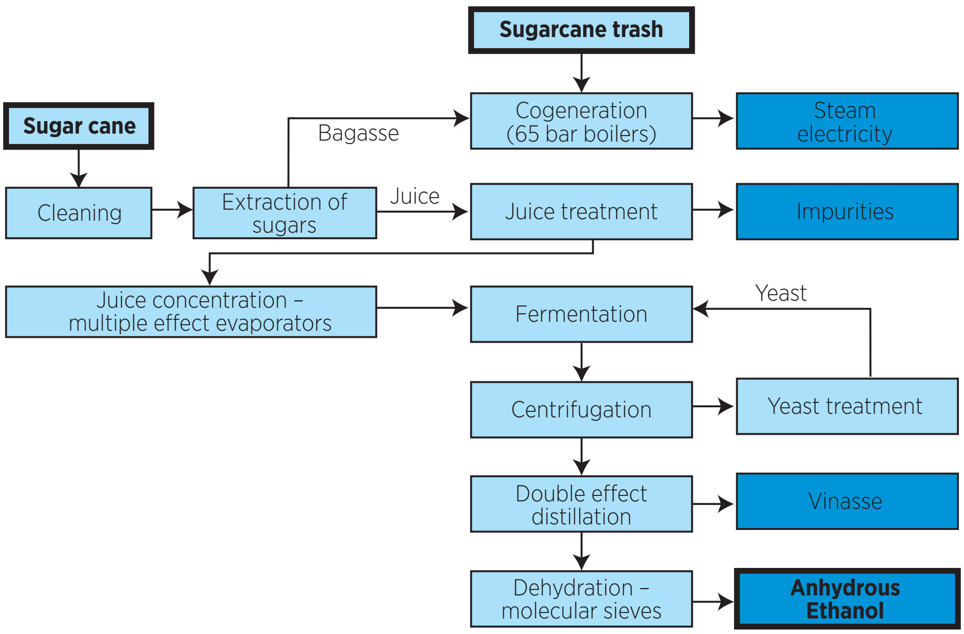


Figure 4.1: Simplified sugar cane to ethanol production process

Source: Based on Dias, 2013.

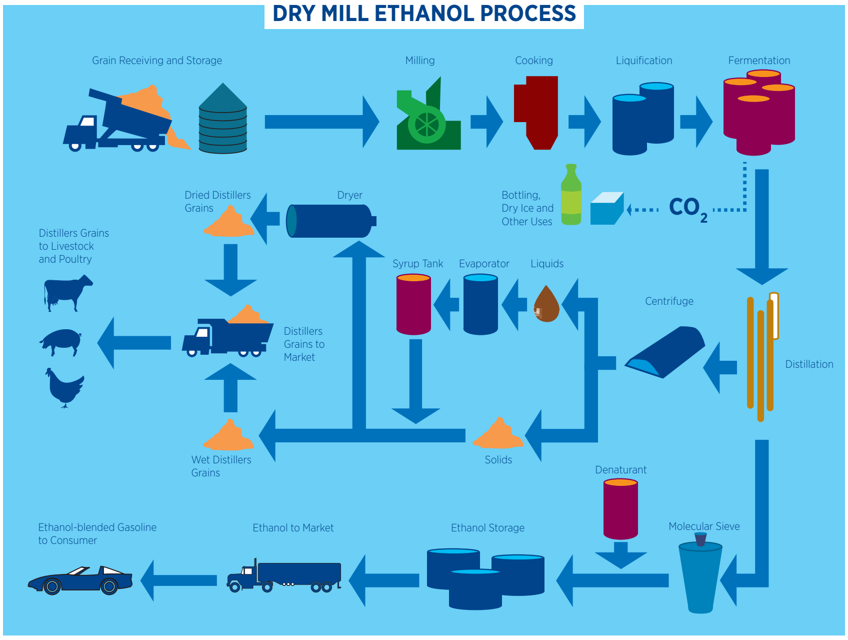


Figure 4.2: Simplified corn-to-ethanol production process

The process for producing ethanol from sugar or starchy crops is almost identical from the fermentation process onwards. Both processes yield residues and by-products that typically have some value. For sugar cane, bagasse is left over that can be used to fire CHP plants to provide process heating and electricity needs for the biofuels plant and potential exports to the grid.[16] With starchy crops, dried distiller grain can be produced and sold as feed to various livestock industries.

16 Integrated advanced ethanol plants will be able to produce conventional biofuels from the sugarcane juice, while the bagasse and other cuttings from the cane fields can be used to produce advanced lignocellulosic biofuels in a separate part of the plant.

Box 4.1: Anhydrous ethanol, hydrous ethanol, blending and flex-fuel vehicles

Ethanol typically contains 7% to 4% water and this is referred to as hydrous ethanol. Anhydrous ethanol is ethanol that has been dehydrated to achieve at least 99% purity.

Ethanol can be blended with gasoline, with typical low-level blends varying from 10-25% and this is typically set by legislation to standardise fuel supplies. Blends of ethanol and gasoline are known according to the percentage of ethanol in the blend. For instance, E15 is a 15% ethanol and 85% gasoline blend. Many modern vehicles[17] can typically run on E10 blends without modification.

However, flex-fuel vehicles are required for higher blends and hydrous ethanol. These vehicles have fuel systems, engines, sensors and management systems (Figure 4.3) designed to run on any blend of gasoline and ethanol from 100% gasoline to E85[18] or even E100 ethanol. Flex-fuel vehicles have oxygen sensors in the exhaust system that identify the fuel composition and adjust the fuel/air ratio appropriately to ensure optimal combustion on varying ethanol-gasoline blends.

In Brazil, flex-fuel vehicles that can be run on any blend of anhydrous ethanol, from E18 to E25 to 'neat' E100 hydrous ethanol have been on sale since 2003. The hydrous ethanol on sale has a maximum water content of around 5%, which is achievable by distillation alone and does not require the additional cost of dehydrating to anhydrous standards. For cold weather, where the lower evaporative pressure of ethanol is a problem,

17 Different manufacturers and countries have introduced vehicles modified to run on ethanol blends at different points in time. Typically only a proportion of the vehicle fleet has these modifications.

18 An E85 limit helps to cut emissions and reduce cold start problems during cold weather.

Figure 4.3: Flex-fuel vehicle characteristics

Source: U.S. DOE.

a small gasoline reservoir is incorporated to allow cold starts on gasoline before switching over to ethanol. Dual-fuel vehicles (e.g. gasoline-biomethane) are also available.

The additional costs of modifying a vehicle to take E85 blends of anhydrous ethanol and become a flex-fuel vehicle are modest. They are estimated to be between USD 85 and USD 150/vehicle for mass production (van Mensch, 2011). The incremental costs of making a car compatible with E85 blends if it is already designed to use E10 blends are very modest and between USD 10 and USD 30/vehicle for mass production. In the North American market these costs are not typically passed on to the consumer now that these modifications are widespread.[19]

19 See http://www.consumerreports.org/cro/2011/01/the-great-ethanol-debate/index.htm

4.2 Conventional bioethanol production costs

Bioethanol production costs are determined by installed capital costs, feedstock costs (which are a function of farming costs, productivity and market supply/demand), operation and maintenance costs and efficiency. However, total production costs for conventional bioethanol products are dominated by feedstock costs. Given that the conversion efficiency of conventional biofuels is approaching its limits, cost reduction opportunities for conventional biofuels are limited.

Total installed costs for bioethanol plants

The cost of a corn ethanol plant in the United States per annual unit of production capacity is around USD 0.7 to USD 0.75 litre/year (Iowa State University, 2013 and APEC, 2010). This is similar to other grain-based plants. Around three-quarters of the total installed costs for a dry mill corn ethanol plant in the United States derives from the EPC contract for the plant's main processes and installations (Figure 4.4). The largest remaining significant investment is for working capital.

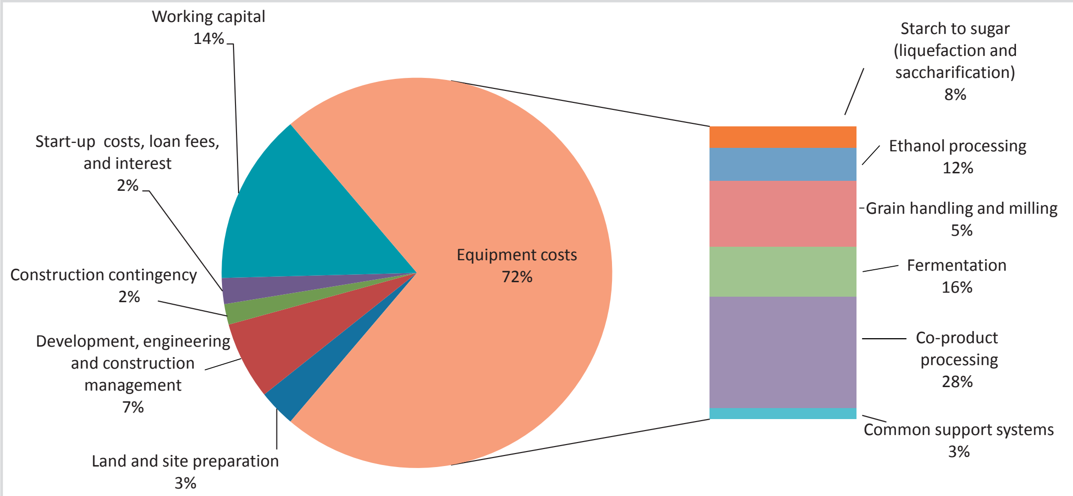


Figure 4.4: Total installed capital cost breakdown for a typical dry mill corn ethanol plant in the United States

Sources: Iowa State University, 2013 and Kwiatkowski et al., 2006.

The engineering, procurement and construction component of an ethanol plant will include the following major components (APEC, 2010):

- Milling/crushing components (sugarcane);
- Cooking tanks (grain ethanol);
- Fermentation tanks;
- Distillation and evaporation columns and piping;
- Dehydration (molecular sieve technology);
- Centrifuges;
- Drying systems (for the distiller grains);
- Boilers;
- Thermal oxidizers;
- Ethanol storage and loadout of the ethanol for delivery;
- Cooling towers;
- Wastewater treatment/digesters;
- Makeup water treatment and storage;
- Electrical/instrumentation/distributed control system;
- Plant air; and
- Miscellaneous plant systems and equipment.

The largest equipment costs are for co-product processing and handling, which account for 38% of the total equipment costs and 28% of the total costs and the fermentation system (23% of equipment costs and 16% of total costs). The ethanol processing requirements of the system account for 17% of total equipment costs and 12% of total costs.

The capital costs of ethanol plants that use sugar cane as the feedstock are typically higher, on a like-for-like basis, than for those that use grains. This is because the feedstock handling equipment tends to be more expensive. However, the impact of local costs on the total installed cost can be significant and an analysis of the capital costs of a United States corn ethanol plant and a Brazilian sugar cane plant suggest that for a large plant (110-135 Ml/year) the capital costs per litre of annual capacity may be similar, given the lower local cost component in Brazil (APEC, 2010).

Feedstock costs of ethanol plants

Total operating costs for ethanol plants include the cost of feedstock, chemicals and yeasts, transport of feedstock to the site, energy costs, labour, maintenance, insurance and other operating costs. However, by far the largest component of operating costs for conventional ethanol plants, whether they are based on sugar or starch crops, is the cost of feedstock. This makes the economics of production heavily dependent on movements in the local and global markets for the feedstock used.

In the United States in 2012, feedstock accounted for around 80% of total production costs, given corn prices ranged from around USD 6 to USD 7.9/bushel (Figure 4.5). This may fall to 75% in 2013 (USDA, 2013 and IRENA analysis) in line with lower corn prices. In Brazil, sugar cane represents a lower proportion of total costs due to low production costs for sugar cane. In 2011, sugar cane costs represented around 60-70% of the total revenue received for the ethanol produced depending on whether the product produced is hydrous or anhydrous ethanol (Figure 4.6).

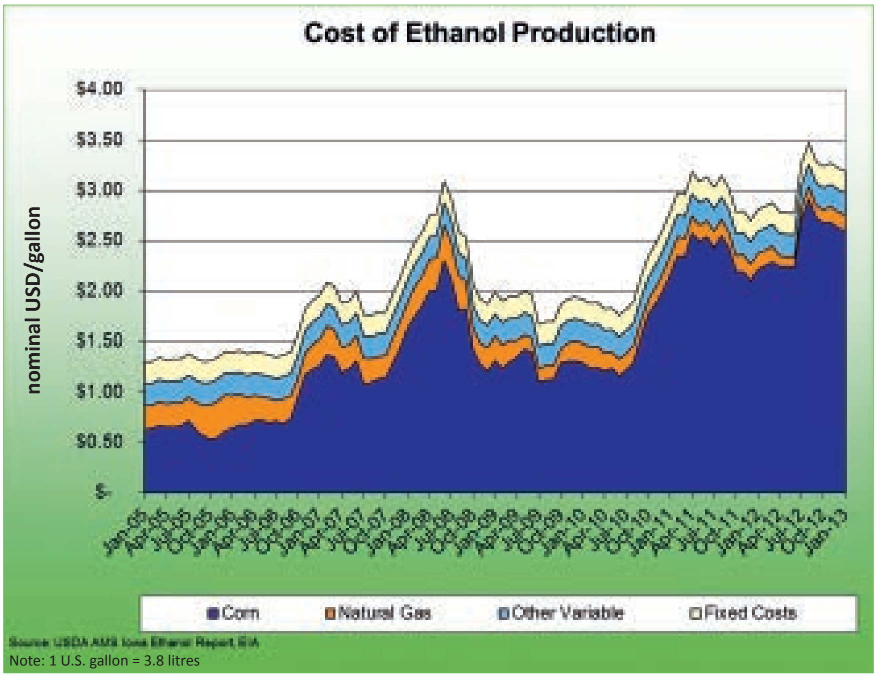


Figure 4.5: Estimated production costs for corn ethanol in the United States at market prices for corn, 2005 to 2013

Source: Iowa State University, 2013

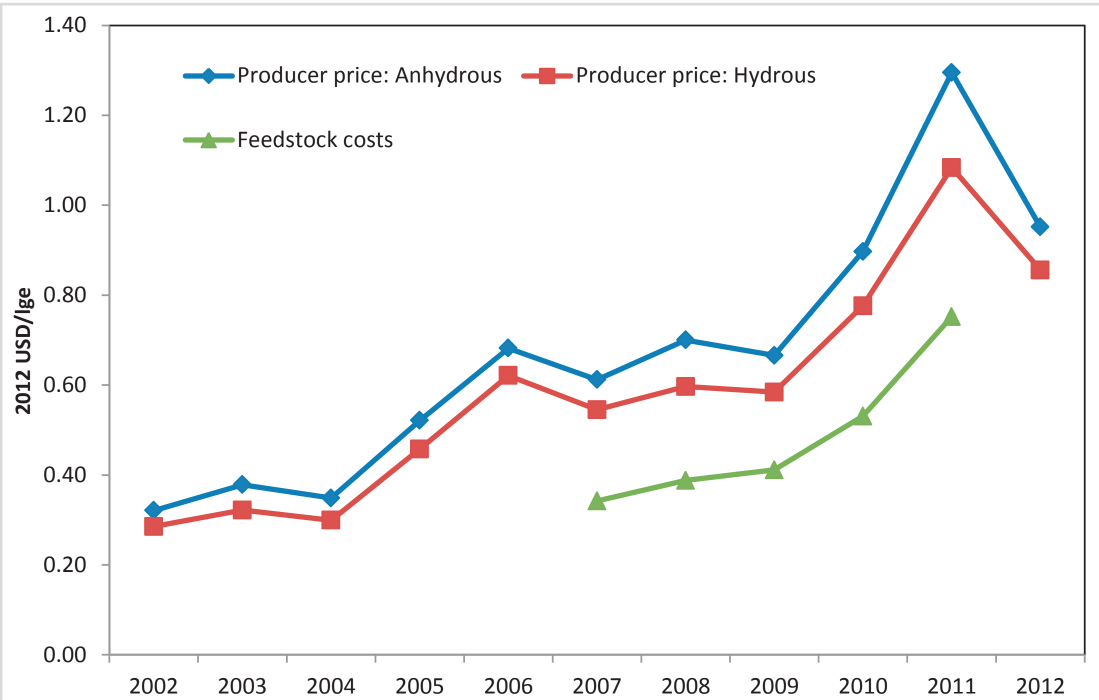


Figure 4.6: Sugar cane ethanol producer prices and feedstock costs in Brazil, 2002 to 2012

Sources: CEPEA, 2012 and 2013 and UNICA, 2013.

Since feedstock prices are such a major part of total ethanol production costs, movements in world, regional and local prices of these inputs have a large impact on the cost of production. Global food prices have been trending higher over the last 12 years, in part due to higher input costs (Figure 4.7). This is especially true of liquid fossil fuel energy inputs and inputs like fertiliser, whose prices are heavily influenced by energy costs. Sustained economic growth over this period has also pushed up the demand for food. Meanwhile, the growing demand for biofuels has also contributed to some extent, although analysis of this area has yet to reach agreement on the relative weight of different factors.

Although prices are an important consideration, the overall feedstock costs are also determined by the yield of ethanol from each feedstock. Table 4.1 presents typical yields for different feedstocks. The yields per tonne

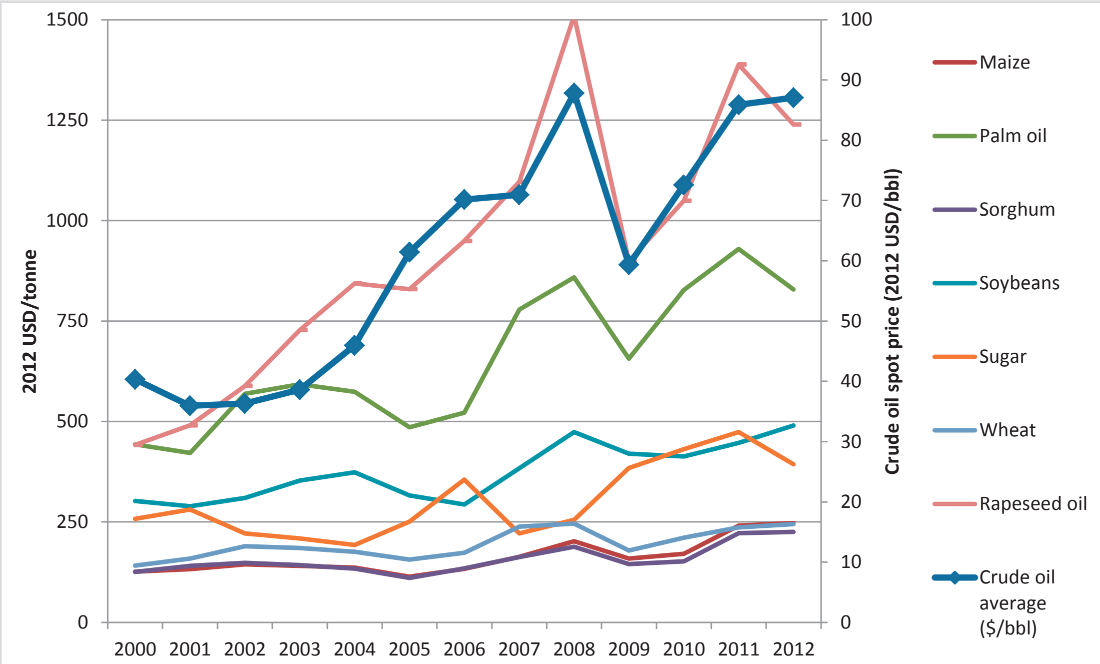


Figure 4.7: Global prices for food-based biofuel feedstocks and crude oil, 2000 to 2012

Source: World Bank, 2013.

Table 4.1: Conventional bioethanol feedstock properties and yields

	Corn	Wheat	Sugar cane
Typical yields (litres/tonne)	400-425	390-470	76-96
Theoretical maximum yield (litre/ tonne)	520	550	
2012 feedstock prices (USD/tonne)			
Minimum	235	249	35
Maximum	310	361	45
2012 feedstock costs (USD/lge)			
Minimum	0.83	0.85	0.55
Maximum	1.15	1.39	0.89

Note: *This assumes 56 pounds/bushel for shelled corn and 60 pounds/bushel for wheat. Corn prices are for the State of Iowa, while global corn prices were in the range USD 267-333/t (World Bank, 2013).*

Sources: Based on Figure 4.7 and AGMRC, 2013; APEC, 2010; CEPEA, 2012; Clarke, 2008; Drapcho, 2008; Perrin, 2009; and Shapouri, 2006.

of input from conventional biofuels, controlling for variations in starch or sugar content from year to year, have generally approached their economic limits. However, incremental improvements in process design, as well as better breeding or engineering of feedstock species to result in more efficient ethanol conversion should provide small incremental improvements in yield in the future. It may also reduce conversion process costs.

The total cost of feedstock for ethanol production from conventional processes is presented in Table 4.1. The ranges presented take into account the different ranges for ethanol yield per tonne of feedstock as well as high and low feedstock prices in 2012. Biofuel yields per tonne of feedstock in the short term for conventional biofuels have evolved modestly. This is due to the generally well optimised production process. This means that feedstock costs will closely follow the commodity prices for the food-based inputs.

Other operating costs of ethanol plants

The other main operating costs of ethanol plants are electricity, process heat (i.e. from gas), enzymes, yeasts, chemicals, denaturant, labour, maintenance and repairs, insurance, water and other miscellaneous expenses. For corn and other grain ethanol plants, the largest expense is typically for the natural gas providing process heat. This can represent 35-45% of the non-feedstock other operating costs in the United States depending on natural gas prices (Figure 4.8).[20]

Other operating costs for sugar cane ethanol in Brazil are lower than for corn-based ethanol in the United States. This is because heat for process needs and all the electricity needs of the plant are provided by combusting the bagasse produced in combined heat and power (CHP) plants. This does however, require higher initial investment. The amount of bagasse available from ethanol production is much larger than the process heat and electricity needs. Significant electricity can be exported to the grid, which can significantly improve the economics of production.

The value of co-products arising from ethanol production

The production of ethanol from sugar cane or grain creates significant quantities of co-products from the feedstock. In the case of grain, dried (or wet) distiller grain

20 Natural gas prices in the United States increased in the second half of 2012, as the market corrected from very low price levels that were the result of weak economic activity and the shale gas boom. Further price rises may occur in the short-term if economic growth accelerates.

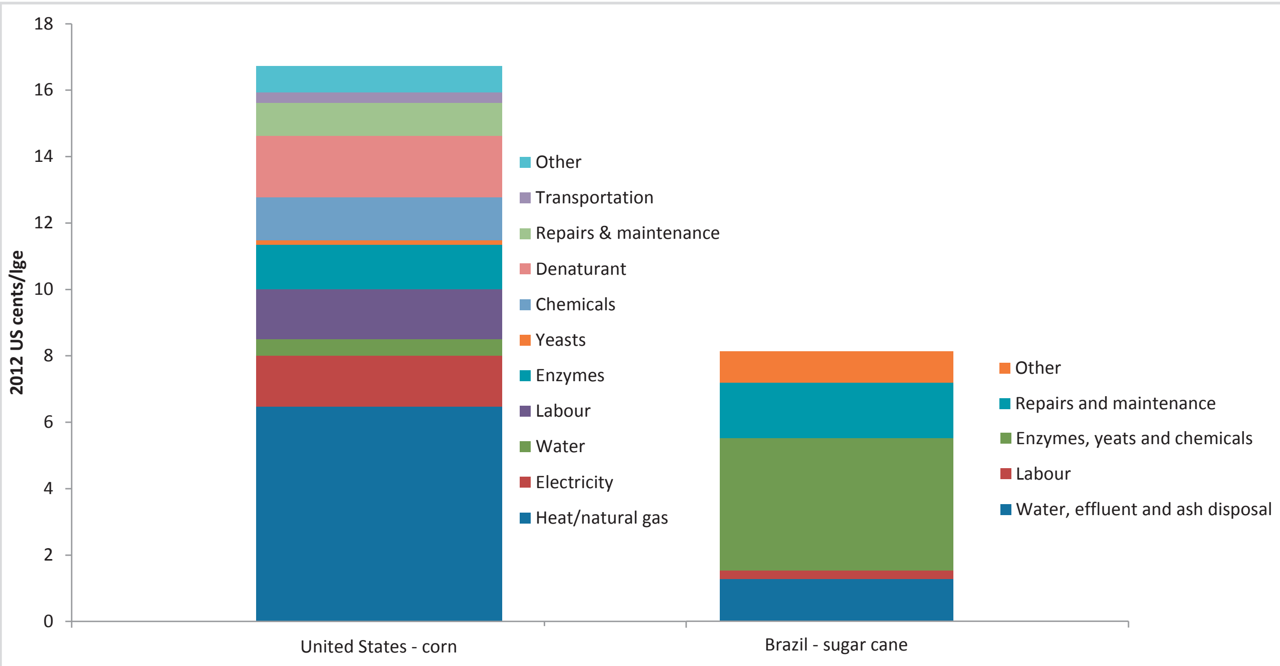


Figure 4.8: Other operating costs for ethanol production from corn in the United States and sugar cane in Brazil

Sources: APEC, 2010 and Iowa State University, 2013.

(DDGS) can be produced after milling and fermentation and then sold as feed.[21] In the case of sugar cane ethanol, bagasse can be combusted to provide process heat and electricity for the plant's process needs, with significant electricity available over and above these needs for export. The sale of these co-products improves the economics of ethanol production.

Corn and DDGS prices closely follow each other, given that DDGS are a co-product of ethanol production from corn (Figure 4.9). Around 30% of DDGS by weight can be produced per kilogramme of corn used in ethanol plants. Unlike modified wet distiller grain (MWDGS), the additional revenue from DDGS needs to be offset against the additional natural gas required to reduce the moisture content. This is around 4.2 GJ/tonne of DDGS and represents an incremental cost for DDGS of around USD 20 to USD 22/tonne. This assumes industrial gas prices of around USD 5.2/GJ in the fourth quarter of 2012 (Iowa State University, 2013 and Perrin, 2009). These incremental costs are typically more than offset by the additional value of DDGS over MWDGS of around USD 140 to USD 155/tonne at the beginning of 2013 in the mid-western United States markets (USDA, 2013).

The production of ethanol from sugar cane creates large quantities of bagasse that can be burned to provide process heat and electricity, as well as electricity for export.[22] For a stand-alone ethanol plant, the use of high efficiency boilers to produce steam to drive turbines and create electricity would increase capital costs by around USD 40 to USD 60 million (28% to 42%). This is for a plant producing 1 000 m^3/day of anhydrous ethanol, but it would yield electricity for sale to the grid of 68 and 155 kWh/tonne of sugar cane (Dias, 2010).[23] The larger incremental investment is required where, in addition to burning bagasse, around half the harvested sugar cane leaves and tops are not burned in the field, but at the ethanol plant. This more than doubles the amount of electricity available for export to 155 kWh/

21 DDGS is something of a misnomer, as it still contains around 10% moisture. This is significantly lower than MWDGS, which contains about 50-55% moisture, while wet distiller grain typically contain around 65-70% moisture.

22 Advanced ethanol plants will also be able to convert this and other cuttings from the cane fields into lignocellulosic ethanol.

23 This compares with the ethanol plant's own demand of 12 kWh/tonne of sugar cane where sugar cane preparation and pressing is mechanical, and 30 kWh/tonne where it is driven by electric motors.

Figure 4.9: Weekly Iowa corn and dried distillers grain prices, October 2006 to February 2013

Source: Iowa State University, 2013.

tonne of sugar cane. In Brazil, the value of the electricity exported by burning bagasse reduces the cost of ethanol produced by around 8-10% on average. However, burning the sugar cane leaves and tops as well in larger boilers and steam turbines can reduce the cost of ethanol production as much as 15% compared to case where all electricity is purchased from the grid.

Total ethanol production costs

Figure 4.10 presents historical producer prices for ethanol in the United States and Brazil, as well as estimated production cost ranges in 2012. Feedstock costs dominate conventional ethanol costs. It is estimated that they accounted for around 80% of production costs in 2012 for corn ethanol in the United States. Figure 4.10 also highlights the major impact of the sale of co-products has on estimated production costs. In 2012, corn ethanol production costs in the United States would have been USD 0.26 to USD 0.36/lge higher than presented if the sales of DDGS were excluded.

Total production costs for Brazilian sugar cane ethanol in 2012 are estimated to have been between USD 0.69 to USD 1.03/lge, compared to average producer prices of around USD 0.95/lge in 2012. The increases in Brazilian prices and costs between 2009 and 2011 were driven by a combination of rising sugar cane prices and a strengthening of the Brazilian Real against the United States dollar. Sugar cane prices for 2012 appear to have declined slightly from their highs in 2011, while the Brazilian Real also weakened against the United States dollar.

Corn ethanol production costs have risen steadily in the United States since 2010 as corn prices rose. Corn prices appear to have stabilised, but at elevated levels compared to prices prior to 2010.

With the increase in corn prices, ethanol production from wheat in 2012 would have been, theoretically, more profitable than corn ethanol production in the United States in some cases. However, the additional investment required to switch over mills to be able to handle and process wheat means it is unlikely that many plants in the United States will risk this investment being stranded by a return of more normal price premiums for wheat over corn in the future.

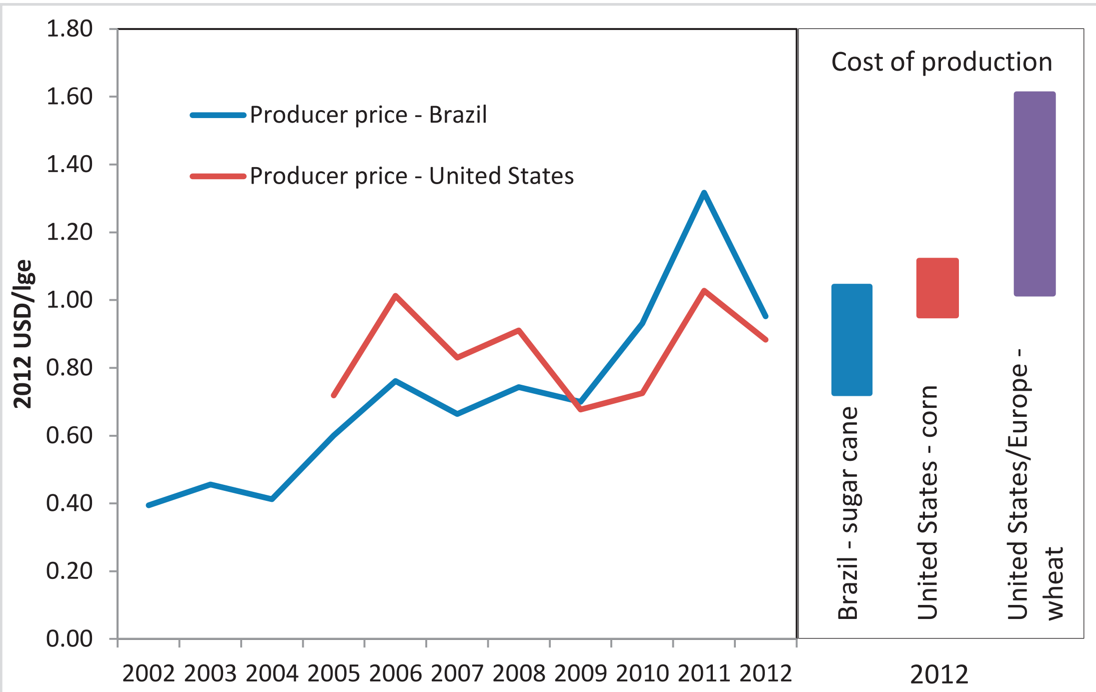


Figure 4.10: Average producer prices for 2002 to 2012 and estimated production cost ranges for conventional bioethanol feedstocks in 2012

Sources: Based on Table 4.1, Figure 4.8, APEC, 2010; Dias, 2010; and Iowa State University, 2013.

4.3 Advanced biofuels: ethanol and gasoline replacements

Advanced biofuels from lignocellulosic feedstocks offer the opportunity to address some of the drawbacks of bioethanol products derived from food crops. Advanced biofuel feedstocks do not have to be grown on pasture or arable land. They do not, therefore, compete with food supplies. As a result, they also have the potential for much higher levels of production and very low GHG emissions. Although advanced biofuels are only just at the early stage of commercialisation, and costs are high, the cost reduction potential is good and higher than for conventional biofuels. However, the technology challenges facing advanced biofuels are significant and commercial production at large scale today incurs significant technical and commercial risk.

Ongoing R&D investment, funded by both public and private sources, is still essential to perfect different pathways and identify new promising production routes. However, the key immediate challenge is to gain experience with commercial-scale projects in each of the most promising pathways now that commercialisation is beginning. This will require major investment in new facilities that, if they are going to succeed commercially, will require appropriate risk reduction strategies from the commercial operators, but also from policy makers and regulators in order to help accelerate commercial deployment to meet the medium- to long-term sustainability goals for transport.

The two main production pathways for advanced biofuels from lignocellulosic feedstocks are:

- Biochemical routes: where enzymes and other micro-organisms are used to convert cellulose and hemicellulose components into sugars,[24] these sugars can then be fermented into ethanol in a manner similar to conventional ethanol.
- Thermochemical routes: these are processes which use pyrolysis/gasification technologies to convert the lignocellulosic feedstock into a synthesis gas and/or liquid biocrude from which a wide range of biofuels can be reformed. Gasoline can be produced from thermochemical routes, but the main products are likely to be biodiesel, bionaptha and jet kerosene so this route is discussed under biodiesel.

The biochemical production route for ethanol from lignocellulosic feedstocks requires four distinct steps:

- Pre-treatment: this is designed to prepare the feedstock for further processing, and it needs to expose the cellulose and hemicellulose to subsequent enzymatic hydrolysis. Given the strong bonds in lignocellulose, this is challenging and expensive.
- Hydrolysis to sugars: this could be done using enzymes or acids. However, enzymes appear to be the cheapest option for the fast and efficient conversion of cellulose to glucose and should provide better yields. Nevertheless, the enzymes required for lignocellulosic feedstocks are more complex and expensive than those needed for conventional ethanol. After hydrolysis, separation of solid lignin allows the liquid glucose and xylose to be fermented.
- Fermentation: this is similar to conventional biofuels, except that yeasts and bacteria are required to convert the glucose and xylose into ethanol. This is more difficult, and more care needs to be taken to ensure nothing obstructs the fermentation.
- Product recovery: this is similar to the process for conventional ethanol where hydrous ethanol is distilled into anhydrous ethanol.

Capital costs for an advanced biofuel ethanol plant

The installed costs of a commercial-scale advanced biofuel plant producing ethanol are only just emerging, and most data available up until recently has been based on engineering estimates.

The purchase of the equipment required for an advanced bioethanol plant using corn stover as a feedstock accounts for 55% of the total installed cost (Figure 4.11). Pre-treatment and the equipment for conditioning the pre-treated slurry prior to its passage to the sachirifcation and hydrolisation stage account for 8% of total installed costs. Sacchrification, fermentation and the equipment required for onsite enzyme production account for 11%. The boilers and turbines are the largest single equipment cost at 16% of the total, but allow the plant to meet its own process heat and electricity needs from the co-products and export electricity to the grid. This significantly improves the economics of production, although not to the same extent as for conventional sugar cane ethanol, where more surplus electricity can be produced. Wastewater treatment is also costly and very significant for advanced plants, which can require five or more litres of water per litre of ethanol produced.

The cost of advanced bioethanol plants are estimated to be in the range of USD 1.82 to USD 2.5/litre/year of production capacity (APEC, 2010; Humbird, 2011; and Stephen, 2011) once deployed at scale, processes are

24 The cellulose undergoes enzymatic hydrolysis to produce hexoses (also called C6 sugars) such as glucose. Pentoses (also called C5 sugars), mainly xylose, are produced from the hemicellulose.

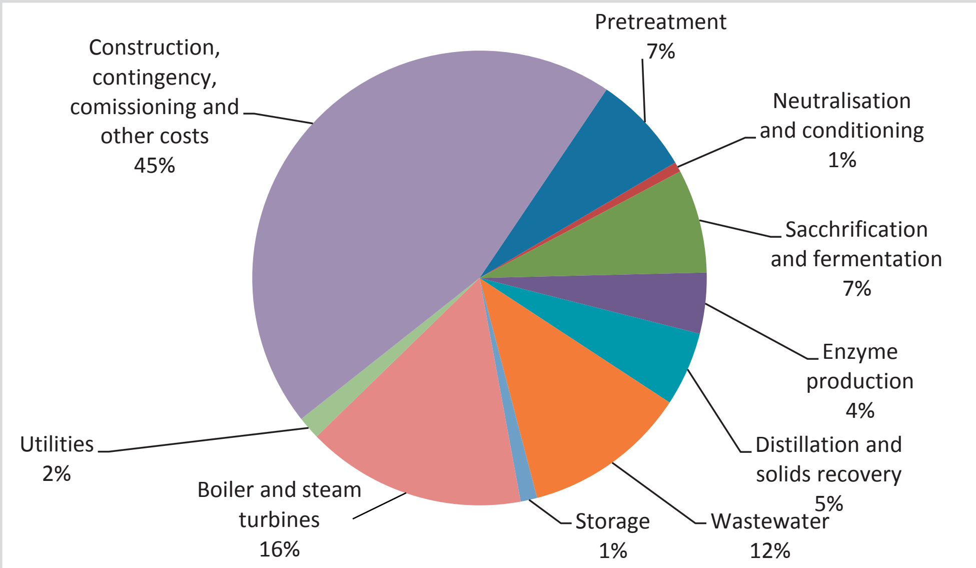


Figure 4.11: Capital cost breakdown for biochemical production of bioethanol from corn stover

Source: Humbird, 2011

de-bottlenecked and modular designs are rolled out. However, the first-of-a kind commercial plants currently being deployed, sometimes at relatively small-scale, appear to have much higher investment costs. Data for recently operational, under construction or advanced biofuels plants planned to be online by 2015 have capital costs in the range USD 1.5 to USD 4.6/litre/year of capacity (Figure 4.12). This is between twice and over six times more costly than conventional ethanol plants and reflects the more complicated pre-treatment and

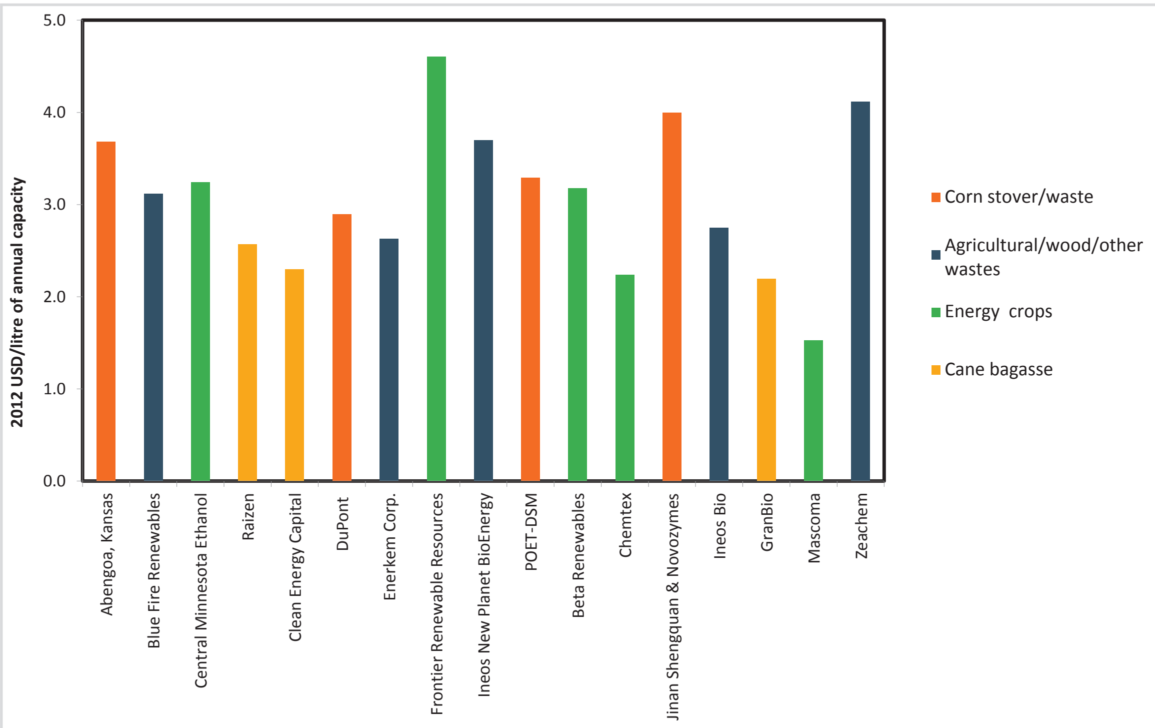


Figure 4.12: Capital costs for current or near future commercial-scale advanced ethanol plants

Sources: F.O. Licht, 2013 and Brown and Brown, 2013.

processing needs required to produce bioethanol from lignocellulosic feedstocks, but also that these plants are typically first-of-a-kind, unlike the mature technologies used in conventional ethanol plants.

The indirect gasification of biomass to produce a syngas that can be synthesised into ethanol and other mixed alcohols (propanol, butanol, pentanol and hexanol) is estimated to be around 10% more capital intensive than for the enzymatic hydrolysis and fermentation route, once fully commercialised. However, it could yield lower overall costs per litre of ethanol produced (Dutta, 2011). This is in an interesting prospect for the future, but is less advanced that enzymatic hydrolysis to ethanol and the costs are therefore more speculative.

Feedstock costs of advanced biofuel plants producing ethanol

Lignocellulosic feedstocks can be agricultural or forestry residues (e.g. corn stover, bagasse, black liquor, hog fuel, forestry arisings and other wood processing wastes, etc) or dedicated crops (e.g. hardwood, softwood, switchgrass, poplar stems). Residues and wastes may be available at low or no cost at the site of production, but perhaps in quantities that would limit the scale of production to uneconomically low levels. Purchasing additional feedstock means higher costs but larger production scales. The planting and harvesting of dedicated feedstock crops can provide additional supply opportunities, but will typically be more expensive.

A key issue for advanced biofuel production is that biomass is very heterogeneous and the proportion of cellulose, hemicellulose, lignin, ash and even the microstructure of the plant at a cellular level varies by feedstock type (Stephen, 2011). Technologies and plant designs able to process a number of different feedstocks in a flexible way are therefore desirable. A multi-feedstock plant could buy the cheapest feedstocks on the market at a specific point of time throughout the year to complement any contracted volumes. However, multi-feedstock plants are more difficult to design and more costly to operate. Progress in overcoming these challenges would help improve the economics of advanced bioethanol plants.

As with conventional plants, the two drivers of the total feedstock cost per unit of ethanol are the ethanol yield per tonne and the price per tonne. In some cases, there are no feedstock costs because residues are available at the food/agricultural or wood processing site. In others, they amount to as much as USD 80/tonne because residues need to be collected from the production site, stored and transported to the ethanol plant. For instance, the collection, chipping and transport of logging residues in the United States was estimated to cost USD 30-35/wet tonne depending on assumptions made (APEC, 2010). The marginal cost of corn stover, taking into account collection, storage and transport is estimated to cost between USD 65 and USD 80/dry tonne (APEC, 2010 and Humbird, 2011).

Many dedicated lignocellulosic energy crops are also being explored for their economics and suitability for advanced ethanol production. In the United States, switchgrass (a native North American perennial grass) can be grown on poor soils and requires minimal fertiliser. Two types exist, with one more suited to semi-arid conditions and another to heavier soils and wetter climates. Yields for commercial operations might be expected to reach around 13.5 to 18 tonnes/hectare. The upper yield in ideal conditions may be as high as 22 tonnes/hectare (Garland, 2008). However, typical yields in less desirable growing conditions are likely to be 4.5 to 9 tonnes per hectare. With these yields, total costs could be USD 65 to USD 100/dry tonne.

Maximising ethanol yields from different feedstocks is crucial to the economics of lignocellulosic ethanol production. Table 4.3 provides details of the composition and potential technical yields from different feedstocks. This is shown for all sugars and for the C6 sugars alone. Actual yields for commercial plants are yet to be determined with certainty, but values of between 110 to 330 litres/dry tonne for agricultural residues and 125 to 300 litres/dry tonne for forest residues might be expected (IEA, 2009 and NREL, 2011). For instance, the yield from corn stover is estimated to be around 330 litres/dry tonne (NREL, 2011). Dedicated energy crops optimised for lignocelluosic ethanol production could achieve even higher yields. For instance, "energycane"[25] could perhaps achieve yields of 375 litres/dry tonne (Alvarez, 2011).

The impact of feedstock costs and ethanol yield on feedstock costs per litre of gasoline equivalent is presented in Figure 4.13. For instance, an advanced lignocellulosic ethanol plant using corn stover at a cost of USD 70/dry tonne and yielding 330 litres/dry tonne would have feedstock costs of USD 0.32/lge. A yield of 330 litres/dry tonne is around 77% of the maximum theoretical yield from corn stover (Humbird, 2011). One important issue to consider is that higher yields are not necessarily more economic from an overall production cost basis. This is because there is a complex trade-off between process design, capital costs, operating costs and the impact on the yield from the feedstock (Table 4.3).

25 A cross between commercial sugar cane and a species with higher fibre and lower sucrose contents.

Table 4.2: Theoretical maximum ethanol yields from different lignocellulosic feedstocks

	Theoretical yield	
	All sugars	C6 sugars only
	(litres/bone dry tonne)	
Corn leaves	467	276
Corn stalks	476	293
Poplar stems	452	318
Douglas fir (heartwood)	466	439
Douglas fir (sapwood)	445	423
Conifers – normal (average of 27 species)	413	356
Conifers compression wood (average of 27 species)	362	313

Source: Stephen, 2011.

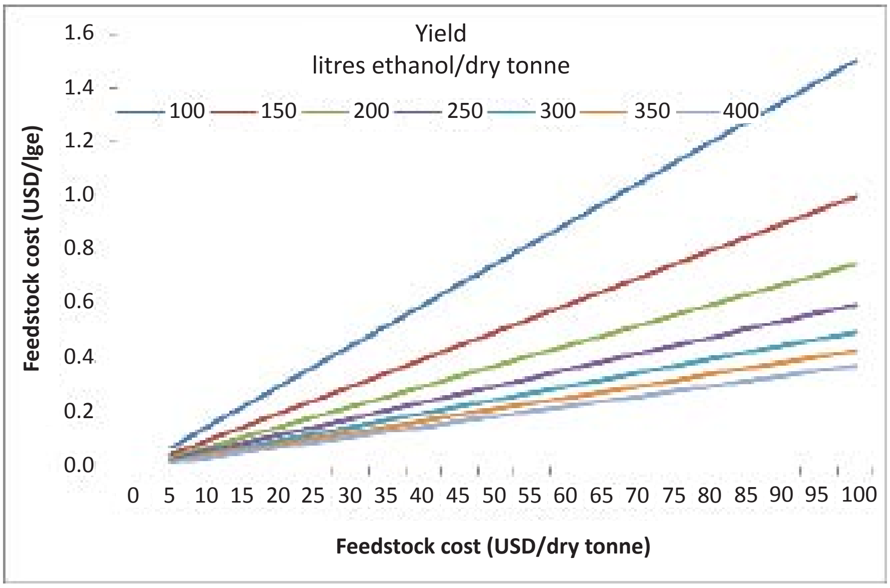


Figure 4.13: Biofuel feedstock costs as a function of ethanol yield and biomass feedstock price

Table 4.3: Capital costs, ethanol yields and production, electricity generation and final ethanol cost for biochemical conversion of corn stover by pretreatment process

	Total capital investment *(USD million)*	Equipment only cost *(USD million)*	Ethanol yield *(litres/t)*	Ethanol production *(million litres/year)*	Electricity export *(USD million/year)*	Product value *(USD/litre)*
Dilute acid pre-treatment (base case)	376	164	288.8	202.2	11.7	0.90
Dilute acid pre-treatment (high solids)	389	169	274.5	192.1	12.6	0.95
Two-stage dilute acid pre-treatment	391	173	177.5	124.2	16.8	1.16
Hot water pre-treatment	361	156	211.1	147.7	11.3	1.21
AFEX pre-treatment	386	167	249.7	174.8	16.9	0.97
Pre-evaporation-distillation	501	209	291.3	203.9	13.6	0.99
Separate C5 and C6 fermentation	386	168	300	210.1	6.5	0.97
On-site enzyme production	434	188	256.3	179.4	-0.8	0.94

Source: Kabir Kazi, 2010.

Other operating costs for advanced biofuel plants producing ethanol

The other operating costs for advanced biofuels are currently estimated to be higher than for conventional biofuels, given the more complex process required for production and also the additional costs of the enzymes.

Chemicals, enzymes and other materials are projected to account for around two-thirds of the other operating costs in the case of corn stover ethanol (Figure 4.14). The costs of chemicals, enzymes and other materials alone are more than the total other operating costs for corn ethanol and more than twice those for sugar cane in Brazil. The significant solid lignin extracted from the feedstock makes the provision of process heat and electricity possible, with significant left over material for the production of electricity for export. Depending on the local electricity market, these exports can have significant value and help to reduce overall production costs.

For indirect gasification and mixed alcohol synthesis, operating costs are lower and dominated by the fixed operations and maintenance costs. This process uses around twice the electricity of hydrolysis and fermentation, leaving virtually no electricity surplus. However, indirect gasification and then synthesis of the syngas yields other mixed alcohols for sale in the ratio of around 1.1 litres of mixed alcohols for every one litre of ethanol produced. The estimated value of these co-products is highly dependent on the market for chemical feedstocks and oil.

Total production costs for advanced biofuels plants producing ethanol

The estimated total costs for advanced lignocellulosic biofuels are evolving constantly. This is because new R&D results come through and commercial experience, albeit limited today, brings new refinements to processes and a better understanding of the challenges and opportunities. Lignocellulosic bioethanol is in its infancy, as far as commercial deployment is concerned, with around 120 Ml of production capacity in the United States and around 70 Ml in Europe in 2012 (F.O. Licht, 2013). Uncertainty is therefore likely to remain about

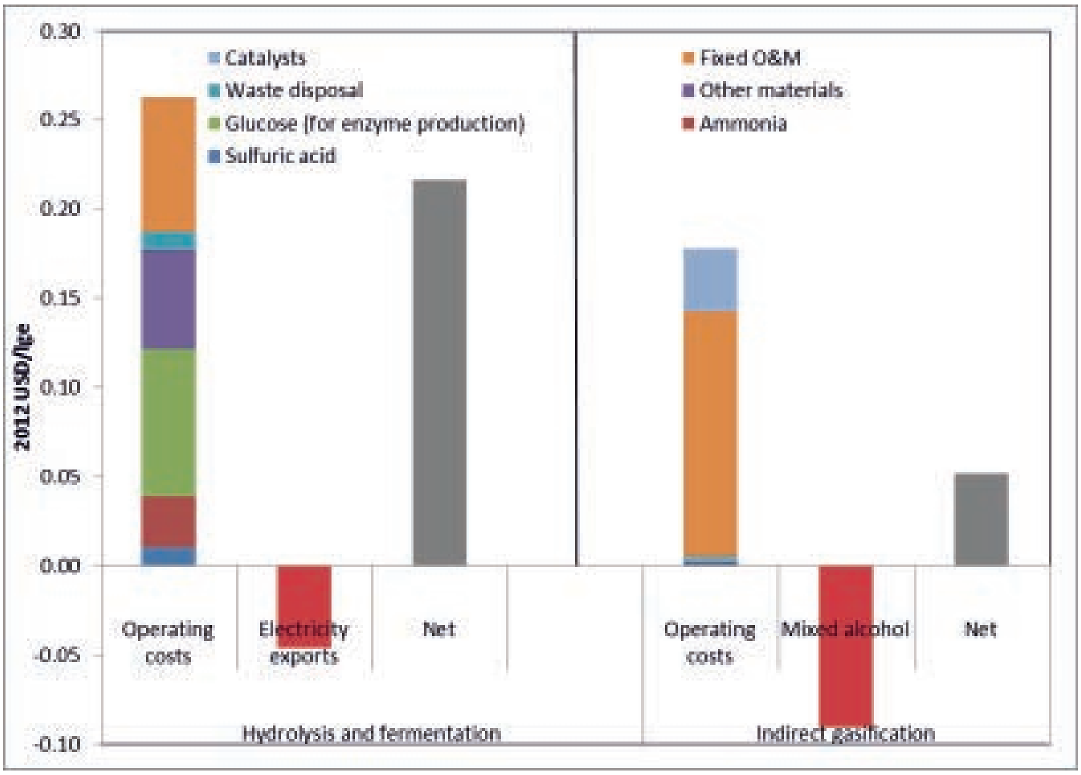


Figure 4.14: Other operating cost breakdown for biochemical production of bioethanol from corn stover and from forestry biomass with indirect gasification and ethanol and mixed alcohols from synthesis

Sources: Humbird, 2011 and Dutta, 2011.

current costs and future cost reduction potential for some time.

The often novel combination of processes means there is a high level of technological risk surrounding commercial scale lignocellulosic bioethanol production. This is true even if many of the individual processes are well known. In addition, given that until recently the estimated costs were also significantly higher than for conventional ethanol, there has been little investment in commercial-scale advanced bioethanol plants.

The cost of current advanced bioethanol from enzymatic hydrolysis is estimated to be between USD 1.04 and to USD 1.45/lge (BNEF, 2013; Humbird, 2011; IEA, 2011; Poet, 2011; and IRENA analysis) and is the pathway which is the closest to widespread commercial deployment. However, the investment cost data for operating, under-construction and plants that will be online by 2015 suggest that if the processes prove to be reliable, efficient and operate continuously at design capacity, then the lower end of that range could be around USD 0.75/lge (Figure 4.15). This is an estimate, as the actual data on the other operating costs and feedstock costs are not yet clear. The data in Figure 4.15 is therefore also based on the assumption that operating costs are a quarter higher than the long-term optimised level (Humbird, 2011) and that feedstock costs are USD 65/dry tonne for agricultural and forestry residues, and energy crops, while municipal solid wastes and sugar cane bagasse costs are half to a quarter of this. However, perhaps the key uncertainty still surrounds the efficiency of the process pathways and the ability to operate continuously (except for scheduled maintenance and estimated unplanned outages) at design capacity.

Recent advances in R&D and process integration suggest that costs for future plant using today's enzymatic hydrolysis technology could yield bioethanol costs of USD 0.7/lge for a feedstock cost of USD 30/dry tonne and USD 1/lge for feedstock costs of USD 100/tonne in 2020, once the process pathways are proven to be reliable, efficient and able to support continuous production. For this to be achieved a number of factors have to be in place: the learning experience from the initial commercial-scale plants needs to be incorporated into future designs and the scale of the market needs to grow to allow modular designs, rather than expensive,

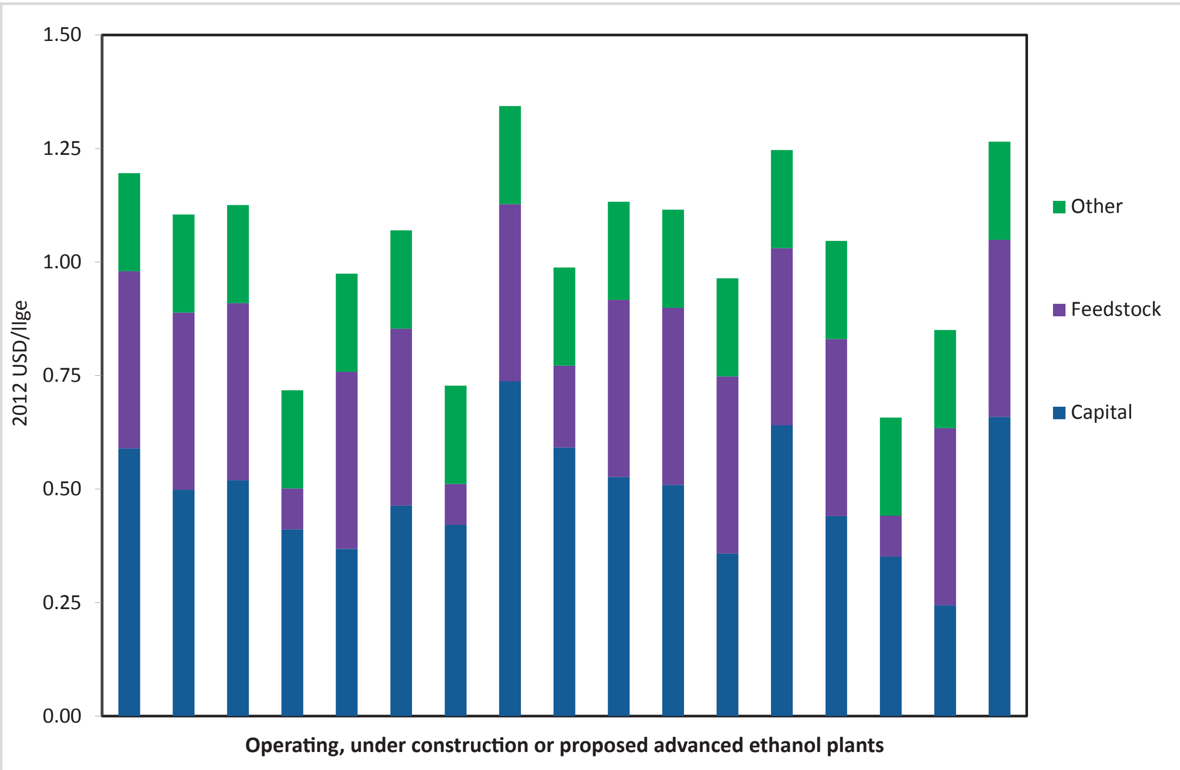


Figure 4.15: Estimated current lignocellulosic bioethanol production costs

Note: *Assumes a 10% cost of capital, a 20 year economic life, feedstock costs of USD 65/dry tonne for agricultural and forestry residues, and energy crops, and USD 15/dry tonne for municipal solid wastes and USD 15/tonne sugar cane bagasse; and that other operating costs are a quarter higher than the long-run costs (Humbird, 2011).*

Sources: Figure 4.12; Humbird, 2011; IEA, 2011; and Poet, 2012.

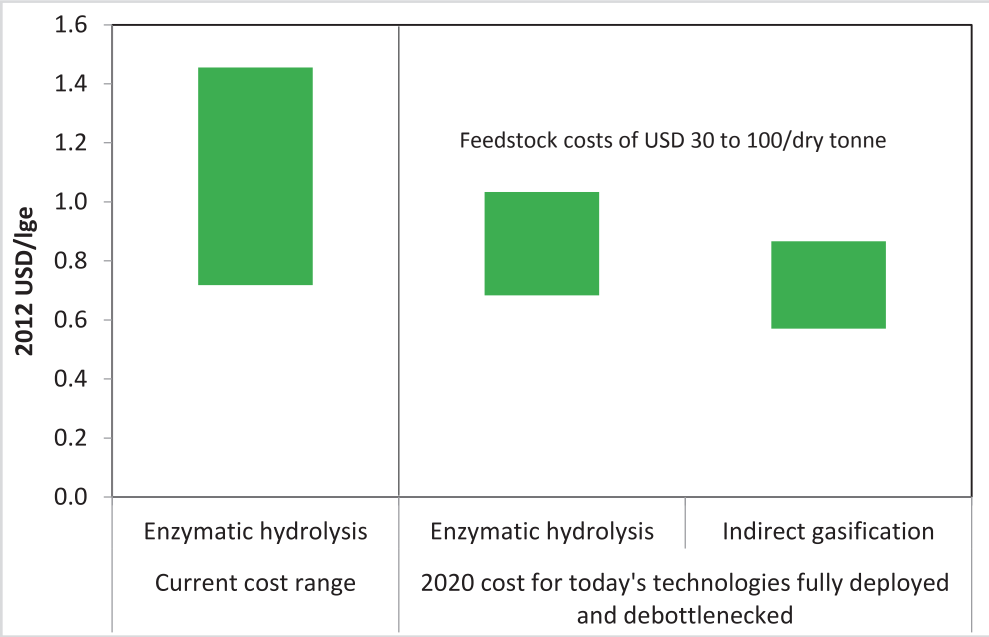


Figure 4.16: Estimated current lignocellulosic bioethanol production costs and future cost with today's technologies

Note: *Assumes a 10% cost of capital and a 20 year economic life for today's technologies.*

Sources: Based on BNEF, 2013; Dutta, 2011; Humbird, 2011; IEA, 2011; and Poet, 2012.

individually engineered first-of-a-kind plants (Figure 4.16).

Indirect gasification and mixed alcohol synthesis of the resulting syngas could eventually lead to even lower costs. With total production costs of between USD 0.6 and USD 0.9/lge for feedstock costs of USD 30 and 100/dry tonne respectively. However, this technology pathway is yet to be deployed commercially at scale and much needs to be done to prove the reliability, efficiency and plant availability of this process in real world circumstances.

5. Biodiesel

Biodiesel produced by converting raw vegetable oils and fats to esters is a commercially proven pathway both on small and large scales. Biodiesel is predominantly manufactured from rapeseed, soybeans and palm oil.

In the United States, biodiesel production in 2012 was primarily based on soybean oil, although significant quantities of canola oil, corn oil, tallow, white and yellow grease were also used (U.S. EIA, 2013b). In 2009, rapeseed was used as the feedstock for around two thirds of biodiesel in the European Union, with 13% from imported palm oil, 10% from soybeans, 4% from refined vegetable oils and 3% each from sunflowers and tallow (Hamelinck, 2012). Argentina and Brazil also produce significant quantities of biodiesel, predominantly from soybeans. Thailand, Malaysia, Colombia, Indonesia and Singapore all produce biodiesel from palm oil.

5.1 Conventional biodiesel

Biodiesel today is most commonly manufactured from oil or fat (triglycerides) crops by the chemical process of transesterification. If dealing with oil seeds or waste fats (e.g. tallow, used vegetable oils, white grease or yellow grease), the oil and fats need to first be extracted or refined by mechanical or chemical means. After this the liquid oils or refined fats go through an esterification process that separates the fatty acids (hydrocarbon chain) from the glycerine molecule to which they are attached. It then re-attaches them to an alcohol, which is usually methanol or ethanol. This can be done without catalysts, but reaction times are longer and more energy is required. This means small amounts of catalysts (e.g. sodium or potassium hydroxide) are typically used to improve the economics of production. The resulting compounds are FAME or fatty acid ethyl esthers (FAEE) biodiesel and glycerine.

During the process of converting a vegetable oil or animal fat into biodiesel, unwanted reactions can occur and various chemical substances can develop that can contaminate the fuel. The biodiesel can be contaminated by free fatty acids (FFAs), solid particles, mono- and di-gylcerides, catalyst salts, glycerine, methanol, water etc. The FAME biodiesel itself can have variable properties as a result. Separation of the glycerine and FAME products therefore needs to occur rapidly, and further distillation will usually be necessary to achieve a uniform product that meets stringent biodiesel fuel standards.

Conventional biodiesel capital costs

The total installed costs for biodiesel plant are typically cheaper than for ethanol and are typically between USD 0.45 to USD 0.8/litre/year of capacity (Figure 5.1) in developed countries (APEC, 2010 and Iowa State University). Total installed costs can be lower in developing countries, where the local cost component of the manufacturing can help keep costs down. The Facility for Euro-Mediterranean Investment and Partnership of the European Investment Bank analysed the potential for biodiesel production. It estimated installed costs for a range of countries in North Africa and the Middle East at USD 0.25 litre/year of production capacity (Agra CEAS, 2011).

The level of FFAs in the feedstock has an important impact on the cost of the biodiesel plant. The higher the level of FFA in the feedstock, the higher the capital costs, as extra equipment is needed for the pre-treatment of the feedstock before it can go through the transesterification process (Figure 5.2).

There are significant economies of scale for biodiesel plants (Figure 5.2).[26] These economies of scale for the plant size are balanced by feedstock yields and availability, as higher transport costs from an ever increasing radius around the plant will reduce the cost savings from larger plant sizes at a certain point.

26 The scaling factor for biodiesel plants is estimated to be between 0.65 and 0.89 (Amigun, 2008 and Yii-Der. 2008).

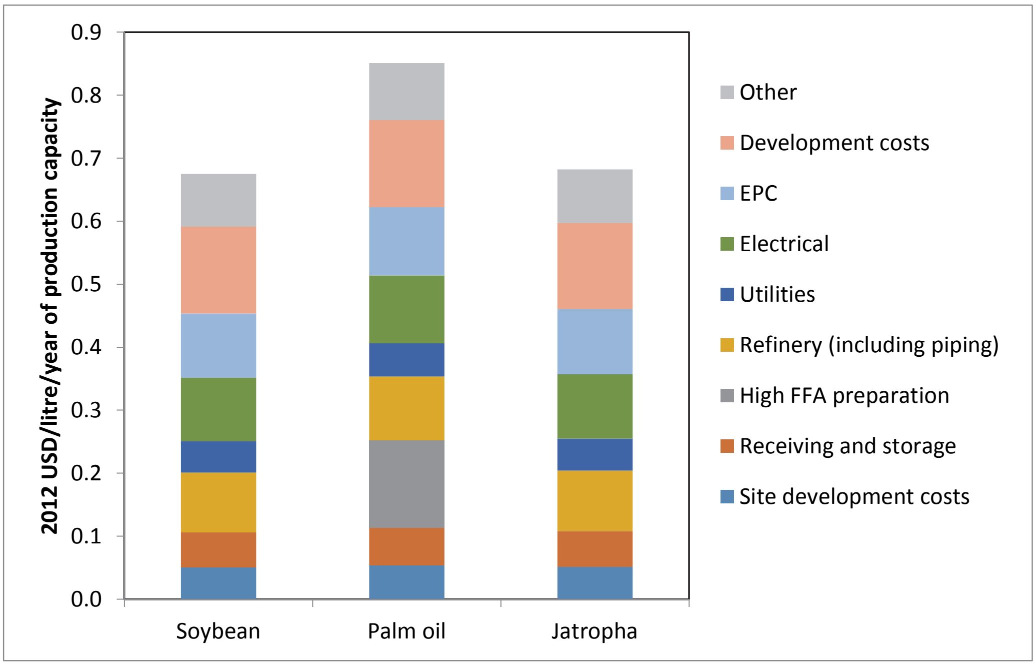


Figure 5.1: Total installed costs for biodiesel plants by feedstock

Source: APEC, 2010.

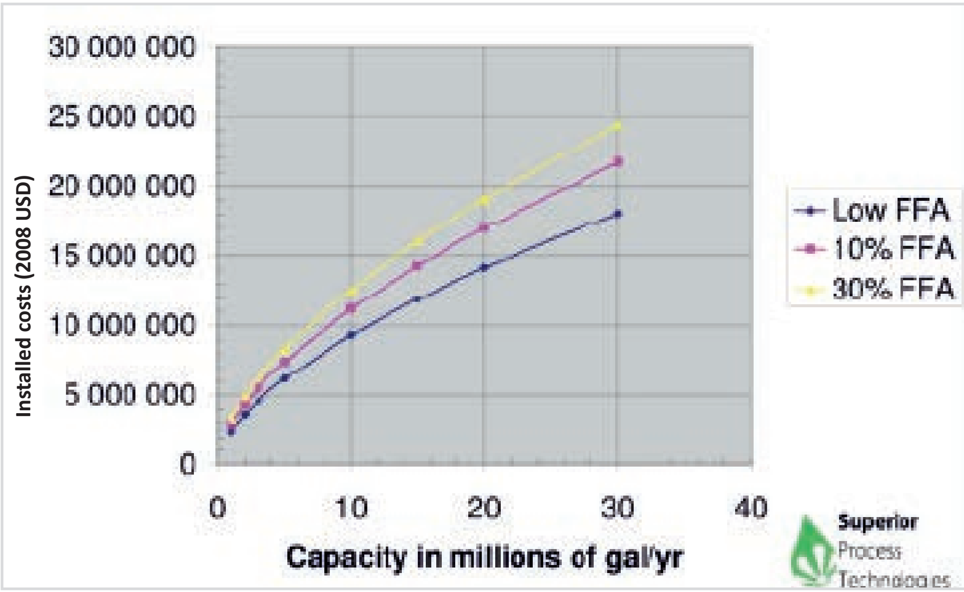


Figure 5.2: Biodiesel installed costs as a function of annual capacity and FFA content of feedstock

Source: Van Gerpen, 2008.

Feedstock costs and biodiesel yields for biodiesel

World prices for vegetable oil feedstocks for conventional biodiesel are presented in Figure 5.3. As can be seen, global prices have been increasing and more than doubled for palm oil and soybean oil between 2000 and 2012. Palm oil prices were around USD 950/tonne in 2012, down from their peak of around USD 1050/tonne in 2011, but still 2.4 times higher than in 2000.

Yields from vegetable oils typically vary between 1000 litres/tonne of oil to around 1120 litres per tonne of oil (APEC, 2010; AGRA CEAS, 2011; and Iowa State University, 2013). Taking high and low global feedstock costs between 2009 and 2012 yields cost per litre of between USD 0.82 and USD 1.12/litre for soybean oil-based biodiesel. For palm oil based biodiesel the range was from USD 0.64 to USD 0.94/litre. Assuming jatropha production costs are around 80% of palm oil costs (APEC, 2010), jatropha biodiesel may have had feedstock costs of USD 0.53 to USD 0.78/litre between 2009 and 2012. Rapeseed oil prices in Europe (Rotterdam, free on board prices) grew steadily between 2000 and 2007. They rose sharply in 2008 to a peak of over USD 1 700/tonne in July of that year before collapsing. Prices climbed again in the second half of 2010 and peaked in April 2011 at USD 1 447/tonne before declining steadily to around USD 1 200/tonne in February 2013. Prices between 2009 and 2012 for rapeseed in Europe have therefore yielded feedstock costs of USD 0.67 to USD 1.38/litre of biodiesel.

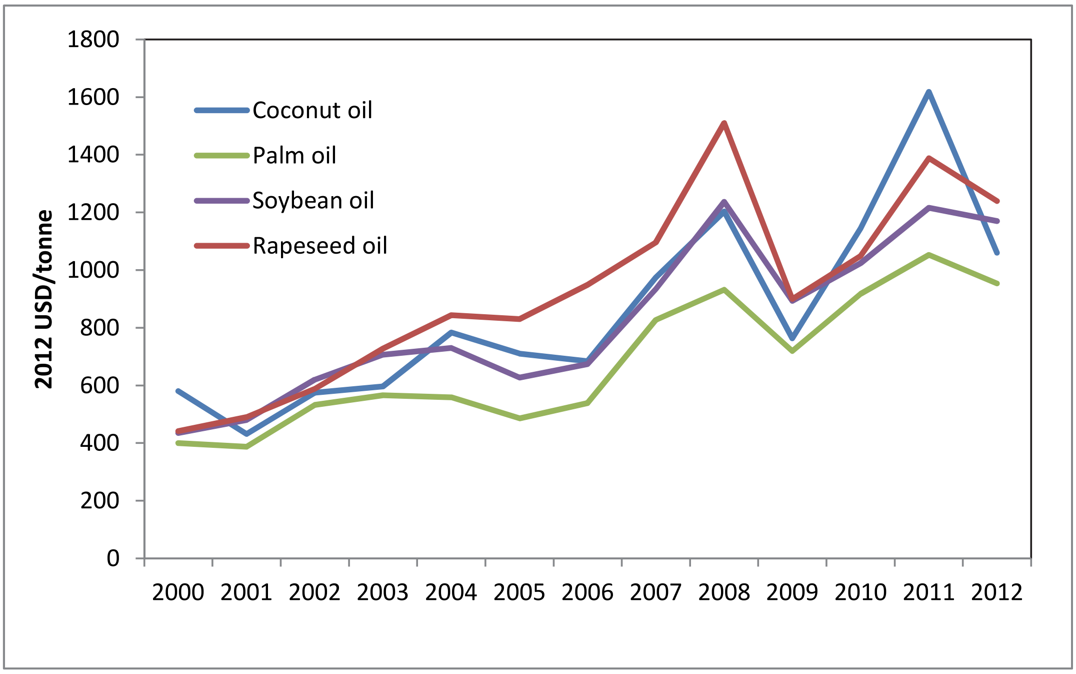


Figure 5.3: Global coconut, rapeseed, soybean and palm oil prices, 2000 to 2012

Source: World Bank, 2013.

Table 5.1: Conventional biodiesel global crop prices and feedstock costs per unit of biodiesel, 2009 to 2012

Oil type	Yield (litres/tonne)	Feedstock prices (USD/tonne)		Feedstock cost (USD/litre biodiesel)		Feedstock cost (USD/lde)	
		Min	Max	Min	Max	Min	Max
Soy	1087	893	1216	0.82	1.12	0.87	1.18
Palm	1116	719	1053	0.64	0.94	0.68	1.00
Jatropha	1077	575	842	0.53	0.78	0.57	0.83
Rapeseed (Europe)	1086	856	1367	0.79	1.26	0.88	1.35

Sources: APEC, 2010; IMF, 2013; and World DataBank, 2013.

Other production costs and co-product credits

The main non-feedstock operating costs for conventional biodiesel plants are for methanol or ethanol and any catalysts used in production. However, there are important costs for process heat (natural gas) and scheduled and unscheduled maintenance of the plant. Figure 5.4 presents the estimated "other operating costs" per litre of biodiesel equivalent.

The revenue from the glycerine produced as a co-product is dependent on the volatile market for this product. However, it is estimated to typically fall in the range of USD 0.01 to USD 0.06/litre of biodiesel produced (APEC, 2010 and Agra CEAS, 2011). Recent values for the United States were around USD 0.03/litre for biodiesel produced from soybean (Iowa State University, 2013).

Total production costs for conventional biodiesel

The total annualised cost of conventional biodiesel from oil seed crops is dominated by feedstock cost. Recent price volatility has meant the estimated costs of production have varied widely between 2009 and 2013. Estimates of the annual average biodiesel production costs in the United States range between USD 1.01 and USD 1.37/litre between 2009 and 2012, with average production costs in 2012 of around USD 1.3/litre (Figure 5.5).

The average annual production costs for biodiesel from palm oil in Malaysia between 2009 and 2012 are estimated at between USD 0.79 and USD 1.8/litre, with an average in 2012 of around USD 1.05/litre. Production costs for jatropha oil were estimated to have been lower, due to the assumption that feedstock costs are around 80% of palm oil costs. Biodiesel from rapeseed in Europe is estimated to have had the highest production costs between 2009 and 2012. Average annual production costs are estimated at between USD 1 and USD 1.5/litre. In 2012, they are estimated to have been around USD 1.35/litre.

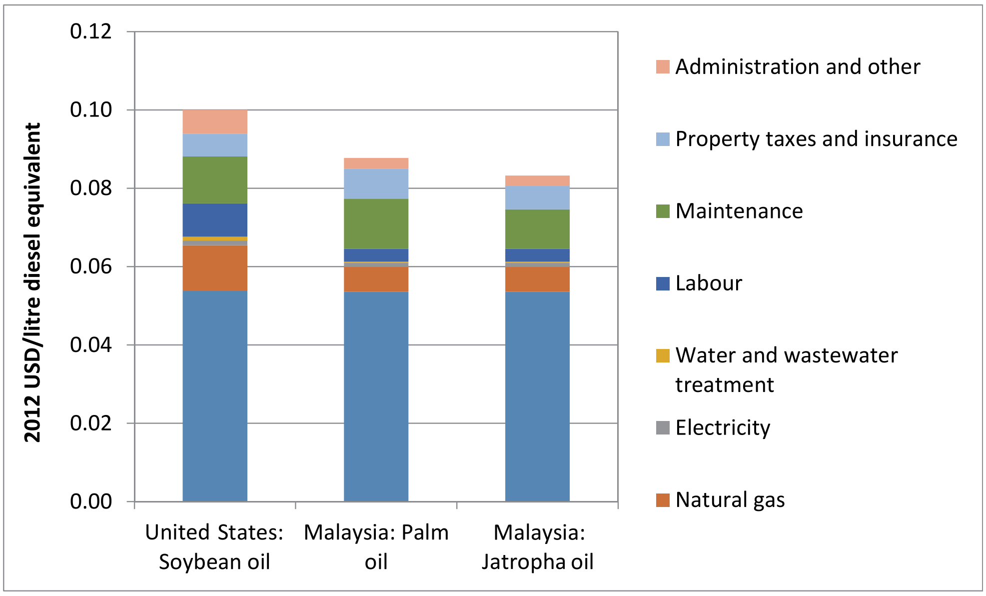


Figure 5.4: Non-feedstock operating costs for conventional biodiesel plants by feedstock

Source: APEC, 2010.

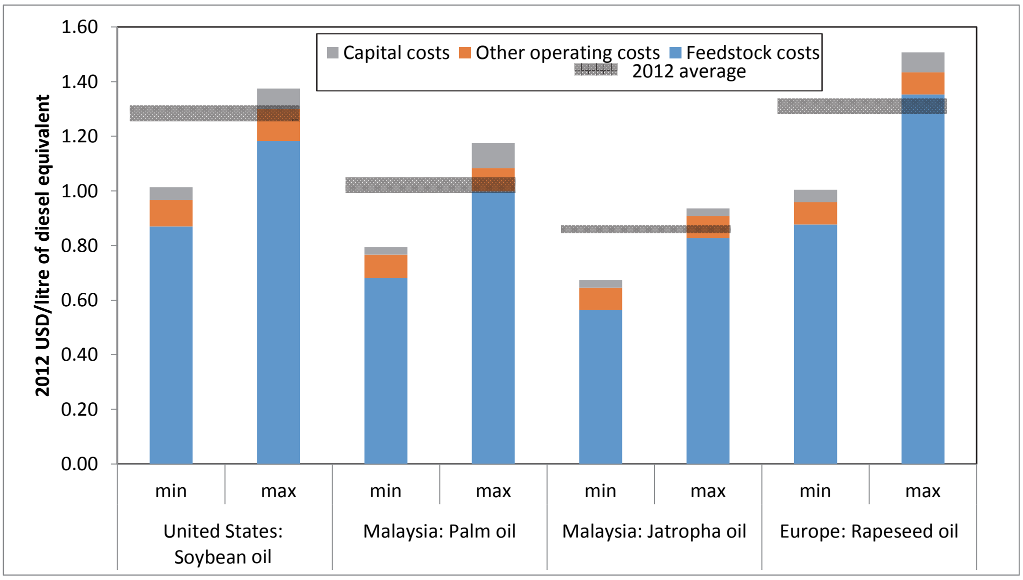


Figure 5.5: Conventional biodiesel total production costs ranges for 2009 to 2012 by feedstock

Sources: Agra CEAS, 2011; APEC, 2010; IMF, 2013; Iowa State University, 2013; World *DataBank*, 2013 and IRENA analysis.

5.2 Advanced biodiesel from lignocellulosic feedstocks

The benefits of advanced biodiesel from lignocellulosic feedstocks are similar to those offered by advanced bioethanol. They also share the common challenge of high costs and unproven technology solutions at commercial production scales. The most promising near term production route for advanced biodiesel is the thermochemical production route. However, funding is needed for more R&D, demonstration and commercial-scale projects to explore the most promising pathways, debottleneck and optimise processes and gain experience with different feedstocks and operating regimes.

The thermochemical routes for biodiesel involves processes where pyrolysis/gasification technologies are used to convert the lignocellulosic feedstock into a fuel, synthesis gas or crude bio-oil. A wide range of biofuels can be reformed from this. Although gasoline can be produced from thermochemical routes, this is predicted to be more expensive than biochemical routes, so the main products are likely to be biodiesel, bionaptha and jet kerosene.

The main three routes for thermochemical biodiesel production are:

- Biomass-to-liquids, which includes Fischer-Tropsch synfuels and biodiesel, from gasified biomass.
- Diesel production through hydrothermal upgrading.
- The fast pyrolysis of biomass into "bio-oil" and then refined to diesel.

Gasifying biomass opens the way to producing a number of different fuels, including biodiesel. The most common means of achieving this is through digesters that create the right environment for the bacterial breakdown of the biomass into methane. Typically they use anaerobic digestion. However, impurities mean this is unlikely to be used for biodiesel production.[27]

27 The direct use of biogas as a transportation fuel is discussed in section 6.

A number of new technologies are under development that are designed to yield a variety of different gases and end products. Broadly speaking, they generally use chemicals and/or heat to break down the biomass into gases with little or no microbial action. The choice of which process is used depends on the feedstock, as lignin cannot be easily transformed into gas, and the lignin component of plants can range from 0% to 35%. For plants with a high lignin content, the heat-dominated process would be more effective and hence economic.

Once the biomass has been gasified, the gas is cleaned and can be turned into a number of different fuels by a number of different processes. The fuels produced could be biodiesel, methanol, synthetic gasoline or dimethyl ether (DME) and gaseous fuels such as methane or hydrogen.

The biomass-to-liquids (BTL) process with gasification can then use Fischer-Tropsch synthesis to convert the gas into diesel fuel and naptha. A variety of other products, mainly chemicals (e.g. waxes and lubes) are produced from this process. If this fuel pathway is to be successful, markets for these other chemicals will need to be found.

An alternative process under development is the hydrothermal upgrading (HTU) of biomass to diesel. In this process, cellulosic materials are dissolved in water under high pressure, but at a low temperature. The process then uses various reactions to convert the cellulosic feedstock into a "biocrude".[28] Various hydrocarbon liquids are then created, predominantly diesel, in a hydrothermal upgrading unit.

"Fast pyrolysis" is another promising process for biodiesel production. It rapidly heats biomass in an air-free environment, and then quickly cools it, thereby forming a liquid "bio-oil" and various solids and vapours/gases. The bio-oil can then be turned into diesel or other fuels.

Advanced biodiesel capital costs

At the end of 2012 no commercial-scale BTL plant via a syngas route was in operation and there was only one BTL plant with fast pyrolysis, refining the bio-crude into diesel.[29] This means capital and perhaps even more importantly operating costs are yet to be determined with any confidence. Advanced biodiesel from algae is only at the pilot phase, and costs are even higher and more uncertain. The difficulties in scaling up process designs from pilot and demonstration scale are numerous and it will take some time for reliable data to emerge.

The current estimates of costs for the *n^th^* commercial plant using today's technologies and performance from pilot-scale or demonstration plants vary by technology.[30] The fast pyrolysis of biomass feedstocks to biocrude and subsequent refining to biodiesel and other drop-in fuels is estimated to have the lowest capital costs at around USD 1/litre/year of production capacity for a plant with annual capacity of 289 Ml/year (Jones, 2009). Low- and high-temperature BTL processes are significantly more expensive. Estimated capital costs for a 123 million litre/year low temperature and a 158 million litre/year high temperature plant are USD 3.5 and USD 3.3/litre/year of capacity respectively for the n^{th} plant (Swanson, 2010). The production of biodiesel from algae is still only at the R&D and pilot stage, so costs are high and very uncertain. Algae production in ponds is estimated to incur total capital costs of USD 10.3/litre/year of capacity. Using photobioreactors to grow algae is more capital intensive, requiring USD 16.6/litre/year of capacity before indirect costs (Davis, 2011 and US DOE, 2013).

There are very few advanced biodiesel commercial-scale projects in operation, although there are numerous plans for the coming years subject to progress in proving processes at near commercial-scale in demonstration projects. It is difficult to compare today's costs to that of what can be expected in the future, once there is large-scale deployment using a variety of feedstocks and processes around the world. It is also potentially misleading until more data is available. Taking this qualification into account, these estimates of cost for the n^{th} plant can be compared to some of the operating and announced commercial-scale advanced biodiesel projects, limited in number though they are.

The first commercial-scale facility using the fast pyrolysis and biocrude refining process route is the USD 215 million KiOR Inc. plant in Columbus, Mississippi. This is a relatively small-scale plant, with production capacity of around 50 Ml/year. Per unit capital costs are expected to be high for a small-scale plant, and are estimated to be USD 4.4/litre. KiOR's second commercial plant will have a capacity of 152 Ml/year and capital costs of around USD 375, implying installed costs of USD 2.5/litre/year of capacity (Figure 5.6). Assuming a plant

28 See Jones, 2009 and NREL, 2013 for a more detailed discussion of these processes.

29 KiOR's 50 million litre/year facility in Mississippi, United States came on-stream in 2012, but will not be running at capacity until near the end of 2013 at the earliest.

30 This concept is not exact in specifying how many plants are required. Humbird (2011) states "the key assumption implied by n^{th}-plant economics is that our analysis does not describe a pioneer plant; instead, several plants using the same technology have already been built and are operating. In other words, it reflects a mature future in which a successful industry of *n* plants has been established".

scaling factor[31] of between 0.7 and 0.8 and taking the capital costs of the n^{th} plant as the base, implies capital costs for these two smaller plants as follows, once the technology is mature. They may be in the range of USD 1.5 to 1.8/litre/year of capacity for the 50 Ml/year plant and between USD 1.2 and 1.3/litre/year of capacity for the 152 million litre/year plant. The gap between these estimates and the costs for these first facilities suggests that significantly more deployment will be required to shift from today's high capital costs for the first-of-a-kind plants to the lower costs projected for the fully commercialised and mature solution.

ClearFuels Collinwood, Tennessee gasification and FT synthesis to hydrocarbon project has a proposed capacity of around 76 Ml/year and capital costs of USD 2.6/litre/year of capacity. Very similar to KiOR's proposed Natchez plant. Sundrop Fuels proposed Alexandria, Louisiana plant has similar installed costs per unit of capacity, but is the most ambitious in scale, with annual production capacity of 190 Ml/year.

31 This is the ratio to be able to scale the known costs for a given plant size, to a hypothetical plant size. Due to economies of scale, this is typically less than one. That is to say larger plants are proportionately less costly and smaller ones proportionately more expensive.

The estimated capital cost breakdowns for BTL and fast pyrolysis solutions per litre of annual capacity are provided in Figure 5.7. The indirect costs associated with the plant including engineering and supervision, construction, legal and other fees are significant for all plants. The contingency reserve for each project is assumed to be 20% of the total direct and indirect costs for the two BTL plants.

Pretreatment, gasification and syngas cleaning account for 33% of the high temperature BTL with FT synthesis and 24% for the low temperature route. In contrast, the share of FT synthesis is higher in the low temperature route, at 14%. The shares for power generation, air separation and balance of plant are similar for low and high temperature gasification and contribute to around one fifth of the total capital costs.

For fast pyrolysis, the hydrogen plant dominates capital costs, accounting for 29% of the total. The front end of the process is the next largest share of capital costs, with fuel handling and preparation and the equipment needed for fast pyrolysis accounting for a fifth of the total capital costs. The equipment required for the upgrading of the pyrolysis oil to biocrude accounts for 18% of the total capital costs.

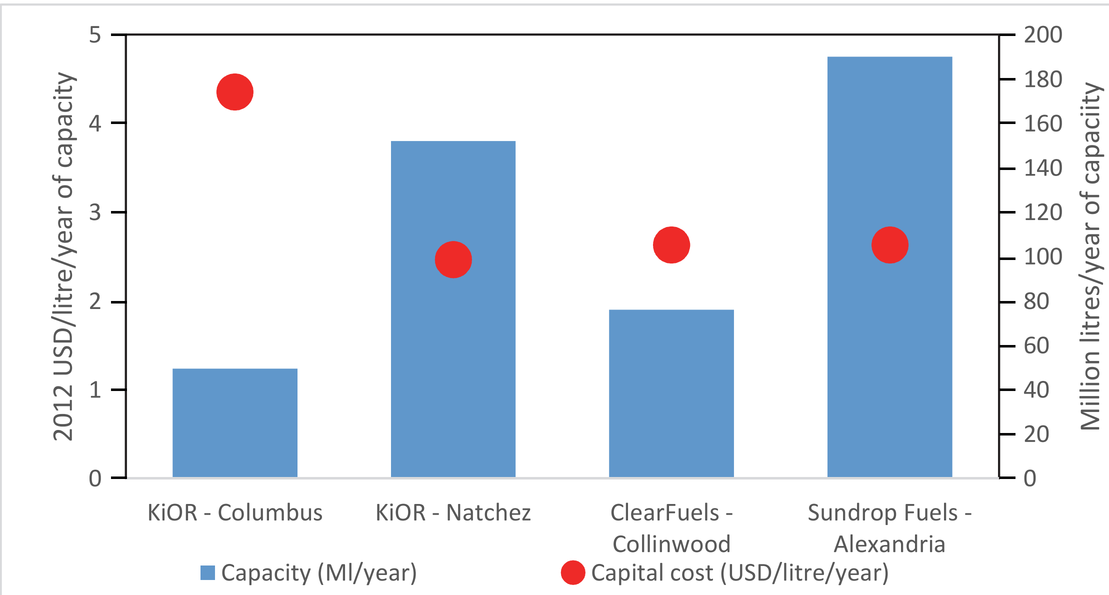


Figure 5.6: Operating, planned or under construction advanced biodiesel plant capital costs

Sources: Brown and Brown, 2013 and F.O. Licht, 2013.

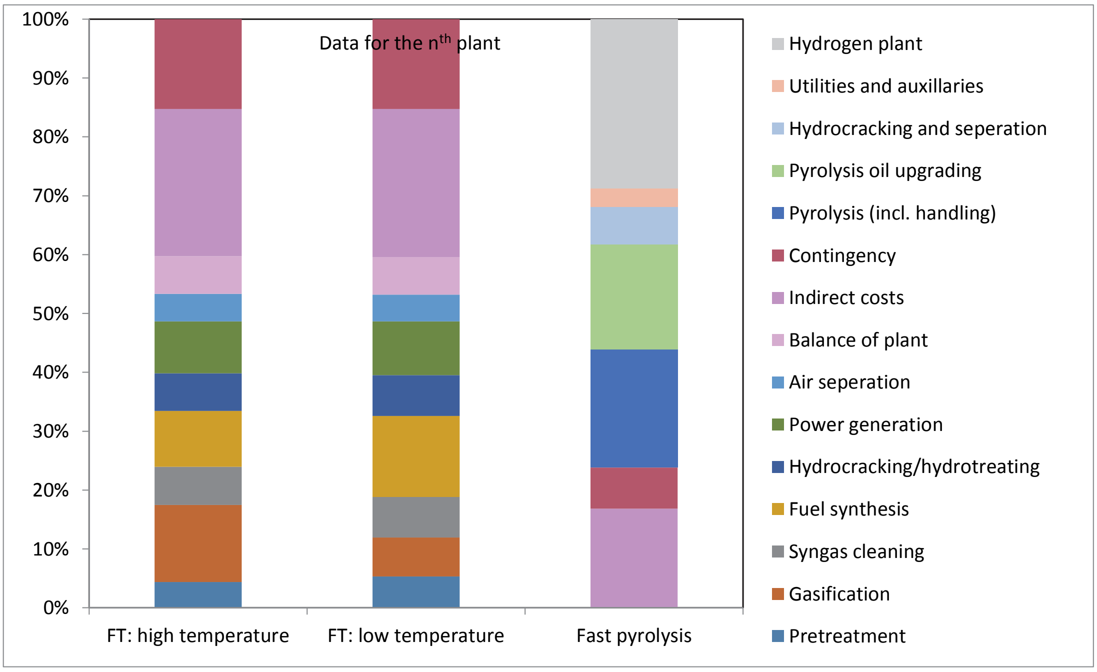


Figure 5.7: Advanced biodiesel capital cost breakdown for BTL with FT synthesis and fast pyrolysis routes, future plant

Sources: Swanson, 2010 and Jones, 2009.

Feedstock costs of advanced biodiesel plants

As with conventional plants, the two drivers of the total feedstock cost per unit of biodiesel are the biodiesel yield per tonne and the price per tonne of the lignocellulosic feedstocks. The issues surrounding feedstock production cost and the heterogeneous nature of lignocellulosic feedstocks are the similar to those faced by advanced bioethanol. The difference for biodiesel is that heteregoneous feedstocks pose a challenge for gasification and the quality and consistent composition of the gas produced rather than for pretreatment and hydrolysis. This can have an impact on the gas clean-up design and costs.

As with lignocellulosic feedstocks for ethanol production, the planting and harvesting of dedicated feedstock crops can provide large supply opportunities. However, it will typically be more expensive than agricultural or forestry residues and wastes that may be available at low or no cost at the site of production. These may be available, though, in quantities that may limit the scale of production to less economic levels.

Where residues are available at the food/agricultural or forestry processing site, feedstocks range from costing nothing to as much as USD 80/tonne[32]. This is where biomass crops are the source, or residues need to be collected from the production site, stored and transported to the plant. For the purposes of this analysis a central estimate of USD 65/dry tonne is used, with sensitivities at USD 30 and USD 100/dry tonne, as with advanced ethanol.

Yields from cellulosic feedstocks for gasification and FT synthesis are projected to be lower than for ethanol at around 180 litres/dry tonne for the low temperature route and 230 litres/dry tonne for the more capital-intensive high temperature route. However, the yield for

32 This value is consistent with information that has been obtained about feedstock costs for at least one of the near-term commercial projects in the United States (NREL,2011).

fast pyrolysis and biocrude to diesel refining is currently estimated to be higher at around 250 litres/dry tonne (US DOE, 2013). KiOR Inc. Columbus facility is expected to yield around this level and a new catalyst is expected to boost this to around 275 litres/dry tonne without any capital modifications, while their long-term goal for future plants is to achieve 340 litres/dry tonne (Biofuels Digest, 2012).

Figure 5.8 presents the costs per litre of biodiesel for the gasification and FT synthesis route and for pyrolysis biocrude that is upgraded to biodiesel for lignocellulosic feedstock costs of USD 30 to USD 100/dry tonne.

Other operating costs for advanced biodiesel plants

Operating costs for advanced biodiesel plants are expected to be significant even after costs are driven down through commercialisation. The fully commercialised, debottlenecked BTL plants of the future using FT synthesis are anticipated to have operating costs of around USD 0.18/litre for high temperature processes and USD 0.22/litre of biodiesel for low temperature processes. Sales of electricity are expected to reduce these costs by USD 0.04/litre for high temperature processes and USD 0.06/litre for low temperature processes, reducing the net other operating costs to USD 0.14/litre and USD 0.16/litre respectively (Swanson, 2010). For fast pyrolysis to biocrude and then upgrading to biodiesel, operating costs are estimated to be around USD 0.16/litre of biodiesel if the hydrogen required is produced onsite from biomass (Jones, 2009).[33]

Fixed operating costs (labour, insurance, etc.) are the largest component of the other operating costs for gasification and FT synthesis, while other major costs are

33 If the hydrogen is produced from natural gas, operating costs rise to around between USD 0.20 and USD 0.22/litre of diesel, assuming a gas price of between USD 5 and USD 7/GJ. However, this increase in costs is offset by a higher yield of final product per tonne of feedstock, 380 litres/dry tonne instead of 250 litres/dry tonne (USD DOE, 2013). Another possibility is the co-location of the fast pyrolysis plant at a refinery, as cheaper hydrogen could be purchased from the refinery and some offgases sold to the refinery. The economics of these options depends on the relative prices of natural gas, biomass feedstock and incremental capital costs. For the co-location with a refinery, they also depend on the available land, costs of the purchased hydrogen and sales value of the offgases.

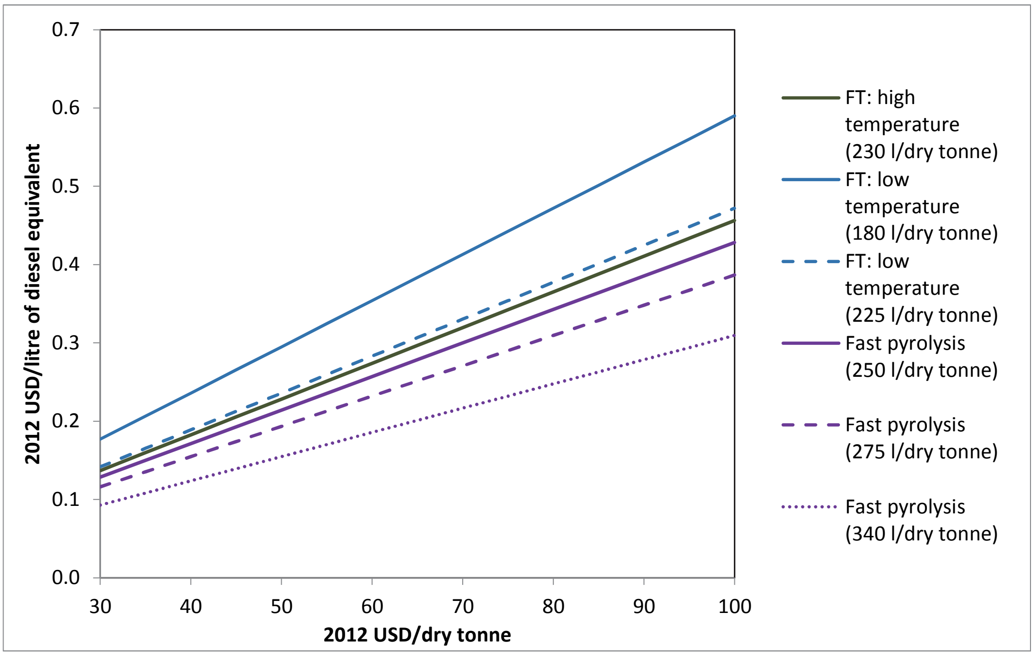


Figure 5.8: Advanced biodiesel feedstock costs per litre as a function of biomass costs and process yields for BTL with FT synthesis and fast pyrolysis

Sources: Based on Biofuels Digest, 2013; Swanson, 2010; and Jones, 2009.

the production of steam and the hydroprocessing costs (Figure 5.9). The lower capital costs for a low temperature route for gasification and FT synthesis are offset to some extent by higher other operating costs of around USD 0.04/litre. However the greater opportunity for electricity exports is estimated to reduce this gap to just USD 0.02/litre of biodiesel in the United States. For fast pyrolysis and upgrading of the biocrude to biodiesel, fixed costs are the largest share of other operating costs when biomass is used for hydrogen production.

The other operating costs for algae are estimated to be significant at around USD 1.3/litre of biodiesel for ponds and USD 1.69/litre of biodiesel for photobioreactors (Davis, 2009 and Davis, 2012). Cost reductions will have to be very large if algae are to compete with other advanced options for biodiesel production, given the large difference in starting points for the estimated commercial deployment costs. On the other hand, the cost reduction potential is good given that this route is still at the early R&D phase. More experience will be required to determine if, or how quickly, costs can become competitive with other advanced biodiesel production routes.

Total production costs for advanced biodiesel

The monthly average crude oil acquisition cost for refiners in the United States in 2012 varied from USD 92 to USD 107/bbl. Meanwhile, the average ex-refinery price in 2012 for resale by month in the United States for diesel fuels ranged from around USD 0.72 to USD 0.97/litre.[34] The selling price required by fully commercialised and debottlenecked biodiesel BTL plants based on gasification and FT synthesis falls within this range. This assumes feedstock costs of USD 65/dry tonne, a cost of capital of 10% and the cost and performance parameters outlined for feedstock and other operating costs in this section. However, it is unlikely that these cost levels will be reached before 2020, unless significant acceleration in deployment occurs in the near future.

By contrast, the fully commercialised and debottlenecked fast pyrolysis and biocrude refining to biodiesel and other drop-in fuels could ultimately have

34 This is from the U.S. EIA's monthly reporting of *Petroleum product retail and wholesale prices by U.S. PAD District and State* for No. 1 and No. 2 Distillate and No. 2 Diesel. See www.eia.gov for more details.

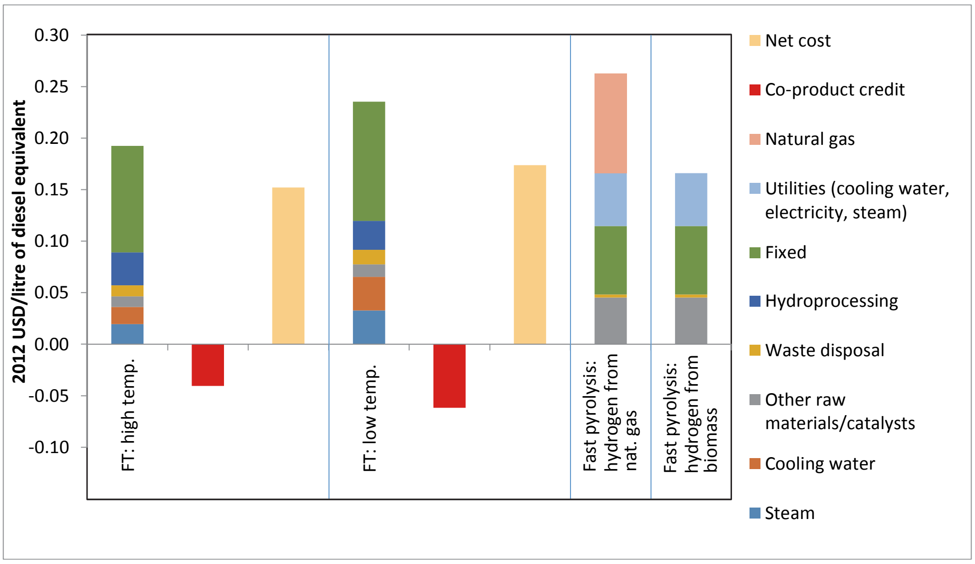


Figure 5.9: Advanced biodiesel other operating costs for BTL with FT synthesis and fast pyrolysis for fully commercialised future plant

Sources: Swanson, 2010 and Jones, 2009.

significantly lower costs. Deployment looks likely to be faster than for BTL routes. Based on KiOR's first-of-a kind plant in Columbus, Ohio, capital costs for their small-scale (50 Ml/year) commercial plant are around USD 4.4/litre/year of capacity. Assuming a feedstock cost of USD 65/dry tonne, that operating costs are one and a half times the long-term potential (Swanson, 2010), and that process debottlenecking restricts output to 80% of planned capacity; then this would imply production costs of USD 1.08/litre. However, KiOR's second commercial plant has three times the capacity and capital costs of USD 2.5/litre/year of capacity. Assuming the same feedstock and other operating costs, successful debottlenecking and that the plant meets scheduled availability predictions, these plants could yield costs of USD 0.76/litre of biodiesel (Figure 5.10).

If these plants can prove the stability of the process and meet the design availabilities, their biofuels will be very close to competitive with the average diesel resale prices in the United States seen in 2012. Fast pyrolysis of biomass into biocrude, then refining this biocrude into biodiesel and other drop-in fuels, appears, therefore, to be a very attractive near-term solution leading to competitive biodiesel production. Two critical questions remain: can these first commercial-scale projects be proved to work reliably and are they capable of being scaled up to levels that make economic sense? If the answer is yes, fast pyrolysis to biocrude and then refining to biodiesel or gasoline could prove to be the first competitive route for second-generation biofuels.

The contribution of feedstock cost to the total cost of advanced biodiesel is significantly lower than for conventional feedstocks and technologies. However, the advanced routes are much more capital intensive and have higher "other operating costs". Even when fully commercialised, the fixed costs of the gasification and

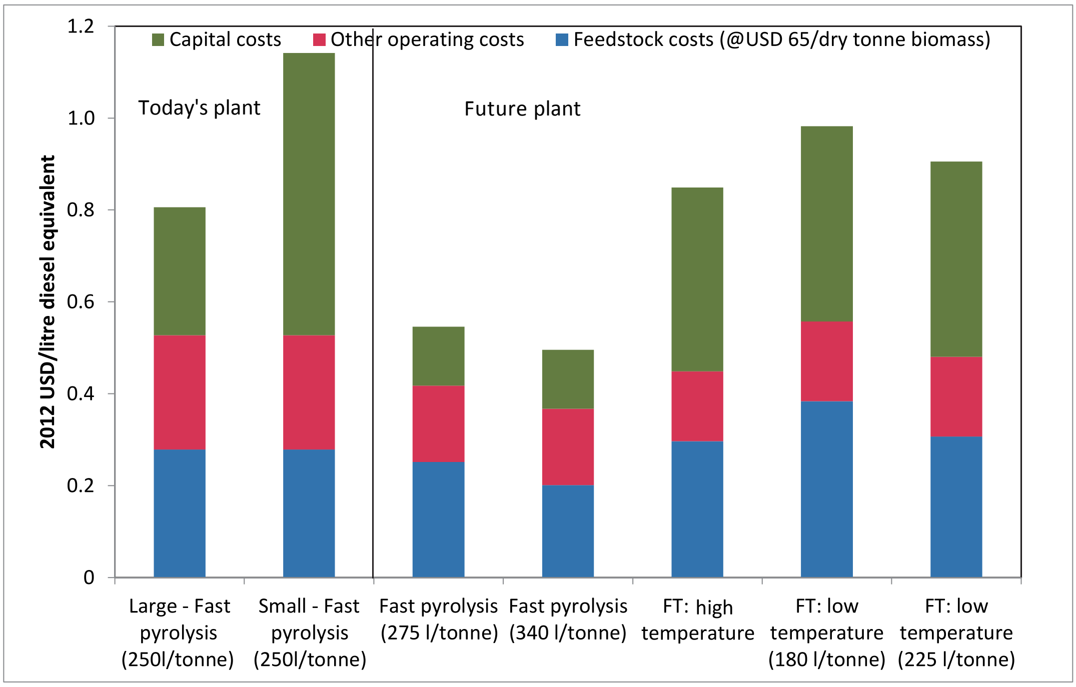


Figure 5.10: Total biodiesel production cost breakdown for fully commercialised future BTL with FT synthesis and fast pyrolysis plants, and today's fast pyrolysis plant

Note: The capital cost data and annual production capacity for the KiOR plants are from publically available data. The non-feedstock costs are an indicative assumption, while feedstock costs may be higher than assumed here. As such, these are order of magnitude estimates of the production costs given these assumptions.

Sources: Based on IRENA analysis and Figures 5.6, 5.7nd 5.8 and 5.9.

FT synthesis route remain the largest share of total biodiesel production costs, accounting for 43-47% of total biodiesel production costs (USD 0.37 to USD 0.40/litre). The fast pyrolysis route is much less capital-intensive and even today's first-of-a-kind commercial plants are estimated to have lower capital costs in absolute and percentage terms than future gasification and FT synthesis BTL plants.

Figure 5.11 highlights the sensitivity of the total production costs for biodiesel to the average biomass feedstock price. The higher operating and capital costs of advanced biodiesel production routes means they are significantly less sensitive than conventional biodiesel. However, securing low cost feedstocks still has a large impact on total production costs.

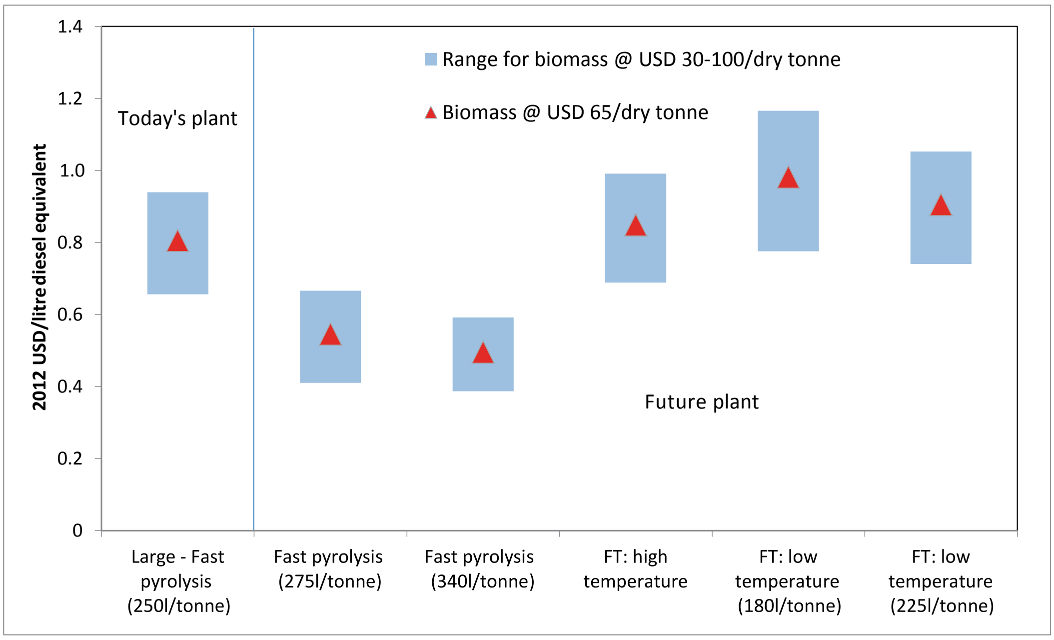


Figure 5.11: Total advanced biodiesel production cost ranges by technology for biomass costs of USD 30-100/dry tonne

Sources: Based on IRENA analysis and Figures 5.6, 5.7, 5.8 and 5.9.

6 BIOGAS

Biogas is composed mostly of methane and carbon dioxide produced from organic material. Like natural gas, it is a versatile fuel and can be used directly to generate electricity, provide low- or high-temperature heat or to power vehicles. For transportation, it can be compressed and used in a vehicle in the same way that compressed natural gas is used. The advantage of biomethane is that it can use existing natural gas vehicle transport and fueling infrastructure, after the biomethane is cleaned and upgraded.

The key challenges for biogas are to grow the market and reduce costs. The use of biogas requires natural or biogas-based fuelling infrastructure and flex-fuel or dedicated natural/biogas vehicles. Alternatively, existing vehicles can be converted to run on biomethane, but at a cost and with a loss in storage space and range to accommodate the compressed biogas storage tank.

The two most promising routes for the production of biogas for transportation are anaerobic digestion (AD) of organic matter and the gasification of woody biomass to produce synthetic biogas. AD is commercially mature and is already used around the world to produce biogas from organic wastes (e.g. refuse, sewage and other effluents) which is upgraded for use in transport vehicles, often local buses or transport fleets. An emerging technology under demonstration in Germany is the power-to-gas technology. This uses renewable electricity from solar or wind to produce hydrogen by electrolysis, which is blended with carbon dioxide to produce "solar-methane" or "wind-methane" depending on the source of electricity. This could help smooth electricity demand and at the same time provide additional biomethane for transport applications.

AD converts biomass feedstocks with a high moisture content into a biogas. AD is a naturally occurring process and can be harnessed to provide a very effective means to treat organic materials, including energy crops, residues and wastes from many industrial and agricultural processes and municipal waste streams (Table 6.1). AD is most commonly operated as a continuous process and thus needs a steady supply of feedstock. The feedstock needs to be strictly checked and usually requires some form of pretreatment to maximise methane production and minimise the possibility of destroying the natural digestion process. Co-digestion of multiple feedstocks is most commonly practised to achieve the best balance of biogas yield and process stability.

Table 6.1: Waste feedstocks and appropriate digesters and characteristics

Type of waste	Liquid waste	Slurry waste	Semi-solid waste
Appropriate digester	Covered lagoon digester/ upflow anaerobic sludge blanket/fixed film	Complete mix digester	Plug flow digester
Description	Covered lagoon or sludge blanket-type digesters are used with wastes discharged into water. The decomposition of waste in water creates a naturally anaerobic environment.	Complete mix digesters work best with slurry manure or wastes that are semi-liquid (generally, when the solids composition is less than 10 %). These wastes are deposited in a heated tank and periodically mixed. The biogas produced remains in the tank until use or flaring.	Plug flow digesters are used for solid manure or waste (generally when the solids composition is 11 % or greater). Wastes are deposited in a long, heated tank typically situated below ground. Biogas remains in the tank until use or flaring.

Source: Centre for Climate and Energy Solutions, 2012.

The two main AD products are biogas and a residue digestate. After appropriate treatment, the resdiue can be used as a bio-fertiliser. Biogas is primarily a mixture of methane (CH_4) and carbon dioxide (CO_2). There are some other minor constituents including nitrogen, ammonia (NH_3), sulphur dioxide (SO_2), hydrogen sulphide (H_2S) and hydrogen.

Biogas is readily used as a fuel in power or combined heat and power (CHP) units and has the potential to be used as a vehicle fuel in the transport sector after appropriate cleaning and upgrading (IEA Bioenergy, 2011).

Germany, with 7 090 digesters, was the leading country in Europe in mid-2011 in both number and installed capacity of AD (Linke, 2011). These have been built to take advantage of the German feed-in tariff for biogas for power generation and are associated with total installed electrical capacity of 2 394 MW. Virtually all of this electrical capacity is located in the agricultural sector where maize sillage, other crops and animal slurry are used. In Germany and the rest of the world, virtually all biogas production destined for the transport sector comes from waste, as this is the cheapest feedstock.

6.1 Capital costs for biogas

Large-scale AD plants using municipal solid waste (MSW), agricultural waste or other industrial organic wastes are proven technologies, but they can be limited in scale by feedstock availability. The use of energy crops increases the opportunities for larger and/or more numerous facilities, albeit with higher feedstock costs. This biogas is then upgraded for use in vehicles. The upgrade removes the high level of CO_2 (typically 45% before the upgrade) from the biogas to create biomethane. The level of impurities such as carbon dioxide permissible in the biomethane varies by country depending on local regulations.

Total installed costs for an AD biogas plant can depend on the feedstock. Those based on manure and sewage are typically cheaper. This is because the handling and storage of the feedstock is already available, or would have to be constructed even if there was no AD being considered. For AD systems based primarily on energy crops (e.g. maize silage) the total investment costs will typically be higher to take into account feedstock storage and handling (Figure 6.1). The digester system is the most expensive component of an AD biogas plant,

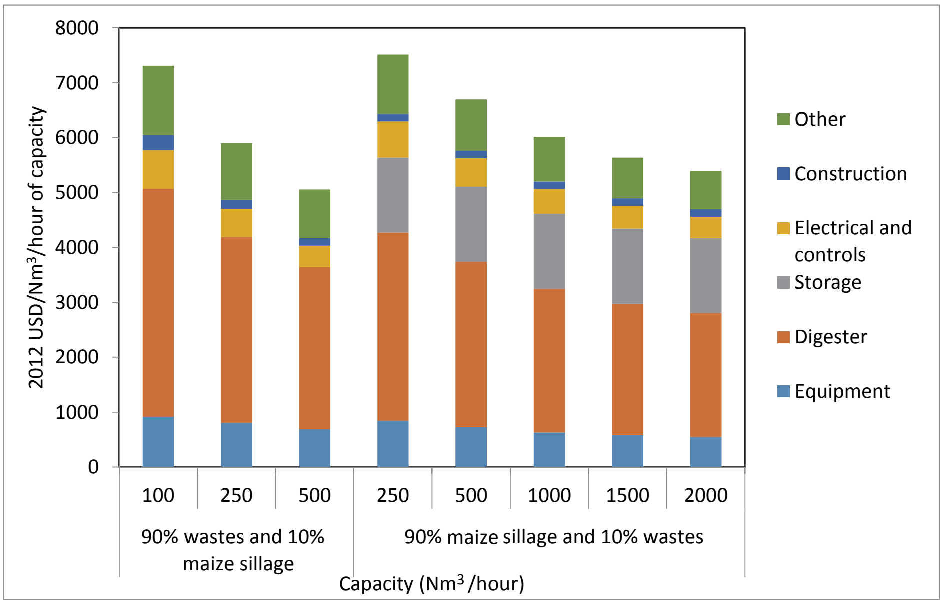


Figure 6.1: Capital costs per unit of capacity for AD systems by plant size and feedstock

Source: Urban, 2009.

although for large-scale systems using energy crops, the cost of storage can also be large.

Total installed costs for AD systems are usually expressed in terms of cost per unit of capacity, where capacity is expressed in terms of *normal cubic metre* (Nm^3)/hour.[35] Total installed capital costs for an AD system using 90% manure and 10% maize silage vary from USD 7 310 to USD 5 050/Nm^3/hour. This is for systems with hourly output capacities of 100 Nm^3 and 500 Nm^3 respectively (Figure 6.1).[36] AD system components have an expected economic life of 15-20 years.

The total installed costs for AD systems using 90% maize silage and just 10% manure vary. They range from USD 5 400/Nm^3/hour for capacities of 2 000 Nm^3/hour to USD 7 500/Nm^3/hour for systems with an hourly output of 250 Nm^3/hour respectively (Figure 6.1).

This section discusses the capital costs for upgrading systems to remove the CO_2 and other impurities from the biogas. The main upgrading technologies are (Bauer, 2013):

- Amine scrubbing process' use a reagent, typically a water solution of amines, which chemically binds to the CO_2 molecule and removes it from the gas.
- Pressure swing adsorption (PSA) is a dry method where the raw biogas is compressed to high pressure and then fed into an adsorption column where the CO_2 is retained, but not the methane.
- Membrane separation uses a dense filter to separate the components in the biogas or a liquid at the molecular level. The selective membranes used for biogas upgrading retain most of the methane while most of the CO_2 permeates through the membrane for treatment.
- Water scrubbing uses a physical scrubber where the CO_2 is dissolved into water in an absorption column in a high pressure environment. The CO_2 is then released from the water again in the desorption column, by addition of air at atmospheric pressure.
- In organic physical scrubbing, the CO_2 in the biogas is absorbed in an organic solvent (e.g. a mix of dimethyl ethers of polyethylene glycol) in a process otherwise similar to that of a water scrubber.

Upgrading allows the combustion of biogas in vehicles and its injection into existing natural gas grids. Table 6.2 presents the typical composition of biogas and landfill gas, as well as the natural gas network requirements for the Danish and Dutch networks. Upgrading the biogas typically requires the removal of CO_2 and other impurities such as hydrogen sulphide and ammonia.

35 This is the volume of gas for a normalised temperature and pressure of 0°C and 1.01325 barA respectively.

36 This corresponds to annual production of 18 TJ and 91 TJ respectively assuming the plant operates for 90% of the year and the energy content of the biogas is 23 MJ/Nm^3.

Table 6.2: Biogas and landfill gas characteristics and natural gas network requirements in Denmark and the Netherlands

		Biogas	Landfill gas	Natural gas (Danish)*	Natural gas (Dutch)
Compounds	Methane (vol-%)	60–70	35–65	89	81
	Other hydro carbons (vol-%)	0	0	9.4	3.5
	Hydrogen (vol-%)	0	0–3	0	–
	Carbon dioxide (vol-%)	30–40	15–50	0.67	1
	Nitrogen (vol-%)	~0.2	5–40	0.28	14
	Oxygen (vol-%)	0	0–5	0	0
	Hydrogen sulphide (ppm)	0–4000	0–100	2.9	–
	Ammonia (ppm)	100	5	0	–
	Lower heating value (kWh/Nm^3	6.5	4.4	11.0	8.8

Source: Petersson and Wellinger, 2009.

As would be expected, capital costs are proportionately higher for small-scale applications with throughputs of 500 Nm^3/hour or less (Figure 6.2). Installed costs for these smaller systems are between USD 4 400 and USD 5 950/Nm^3/hour of capacity for 250 Nm^3/hour systems and between USD 2 600 and USD 3 450/Nm^3/hour of capacity for 500 Nm^3/hour systems. For large-scale facilities which process 2 000 Nm^3/hour or more, the capital costs for biogas upgrading are around USD 1 950/Nm^3/hour of capacity, which adds 36% to the AD biogas plant costs.

For small-scale systems with capacities of 100-500 Nm^3/hour of biogas, the total system costs are between USD 8 950 and USD 13 800/Nm^3/hour, with the upgrading system accounting for 37-47% of the total installed costs. Large systems with capacities to generate and then upgrade 1 000-2 000 Nm^3/hour of raw biogas into biomethane have total installed costs of USD 8 600 and USD 7 350/Nm^3/hour respectively. The share of the upgrading system drops to between 27% and 30% (Figure 6.3).

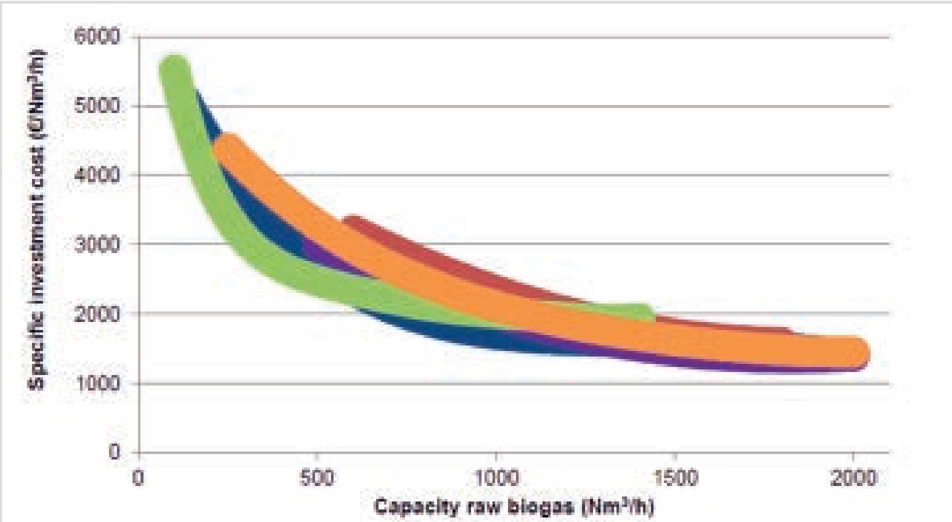


Figure 6.2: Capital costs for biogas upgrading systems by type and size

Source: Bauer, 2013.

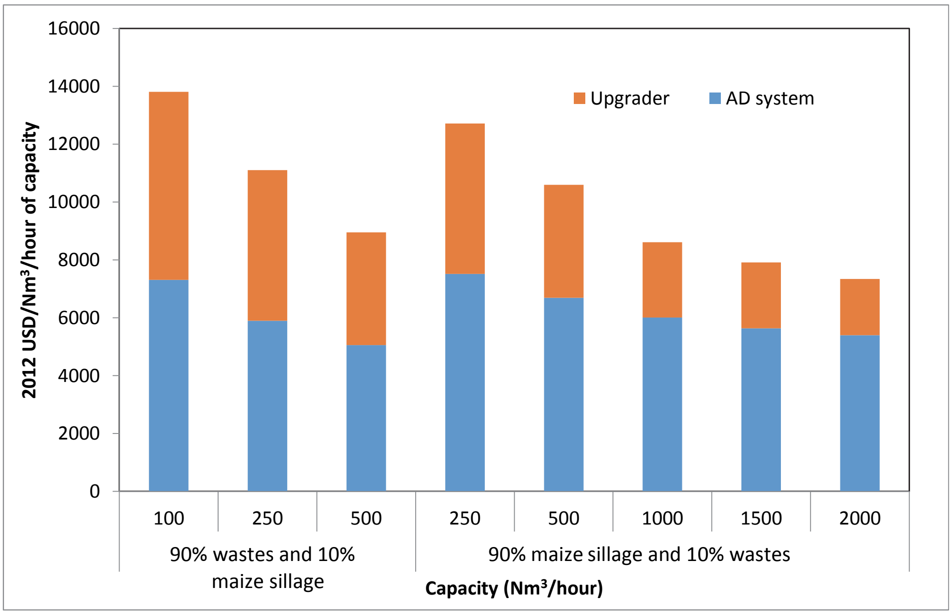


Figure 6.3: Capital costs for biogas systems including upgrader by type and size

Sources: Bauer, 2013 and Urban, 2009.

6.2 Feedstock costs and other operating costs for biogas plants

The feedstock costs for AD biogas systems depend on the source. For waste streams such as manure and sewage, there are typically very low or zero costs for the raw feedstock onsite, as collection and storage systems are required in any event. In these cases, the only costs incurred are operational and the amortised capital costs. In many developed countries, feedstock costs may be negative, as the biogas plant is being paid to dispose of wastes and these revenues sometimes exceed the revenues from biomethane sales. However, for a large centralised biogas plant that is collecting feedstock from surrounding farms, transport costs are often an important consideration.

Energy crops are sometimes purchased to increase the scale of the biogas plant or for the properties they bring to the AD process (e.g. increased yield or more stable digestion). In these cases, the costs of feedstock may quickly become an important component of overall costs. For instance, the plants analysed in Figure 6.4 show the estimated impact of feedstock costs on biogas production costs. These are around USD 0.19/Nm^3 of biogas produced when maize silage is purchased at USD 45/tonne and used for 90% of the feedstock and 10% comes from wastes. This is equivalent to around USD 11.4/GJ of biogas and around USD 20.8/GJ of biomethane assuming the raw biogas has a 55% methane content.

The main non-feedstock costs for AD systems producing biogas are thermal energy for the process, with important contributions from electricity, maintenance and personnel costs (Figure 6.4). Process energy requirements can vary by AD system and feedstock for digestion, but are typically 7-15% of the biogas produced including electricity and thermal energy (Murphy, 2011 and Salter, 2008). The thermal energy required is to raise the feedstock substrate to the temperature required in the digester. Like many biochemical processes, higher temperatures result in faster reactions and throughput. However, the temperature selected for AD is typically a compromise between the optimal biochemical temperature and the economics of heating the digesters. The electricity is required for pumping, feedstock, handling, controls etc.

The operating costs for the upgrader are dominated by the costs for the electricity or heat used. Significant costs also arise from maintenance and other require-

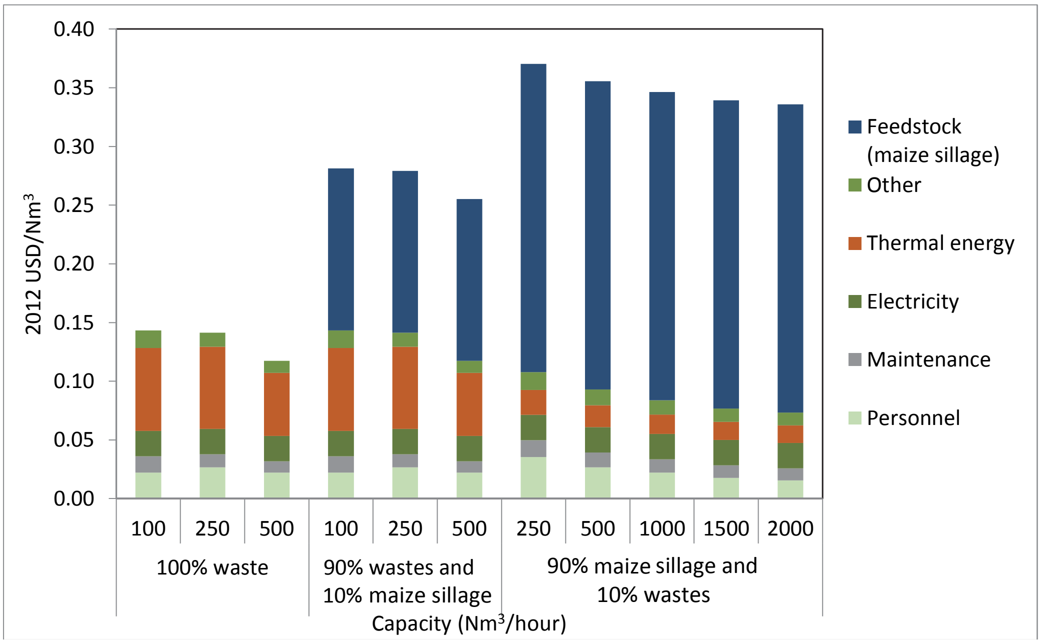


Figure 6.4: Operating costs for AD biogas by feedstock and size

Source: Urban, 2009.

ments (Figure 6.5). Table 6.3 presents the physical requirements for electricity, heat, water and chemicals for the main upgrading options to remove CO_2, while Figure 6.5 presents the operating costs for the upgrading as a function of the raw biogas processing capacity of the upgrader. These operating costs exclude compression, as this will depend on the distribution route for the plant. However, given that vehicles will require biomethane at 200 bar, compression energy of around 0.2kWh/Nm3 will be required (Bauer, 2013)[37] somewhere between upgrading and fuelling.

37 The energy required to compress biomethane from 1 bar to 250 bar is around 0.23 kWh/Nm3. However, the exact figure for biomethane will vary given that different upgraders operate at different pressures and temperatures.

Table 6.3: Selected biogas upgrader systems, their inputs and characteristics

	Upgrader type				
	Water scrubber	*Amine scrubber*	*Pressure swing adsorption*	*Membrane*	*Chemical scrubbing*
Electricity consumption (kWh/Nm^3)	0.23-0.3	0.12-0.14	0.2-0.3	0.2-0.3	0.2-0.27
Heat requirement (kWh/Nm^3)		0.55			
Methane slip (% lost)	1	0.1	1.8-2.0	0.5	
Maintenance costs	Typically 2-3%/year of the installed cost of upgrading system				

Source: Bauer, 2013.

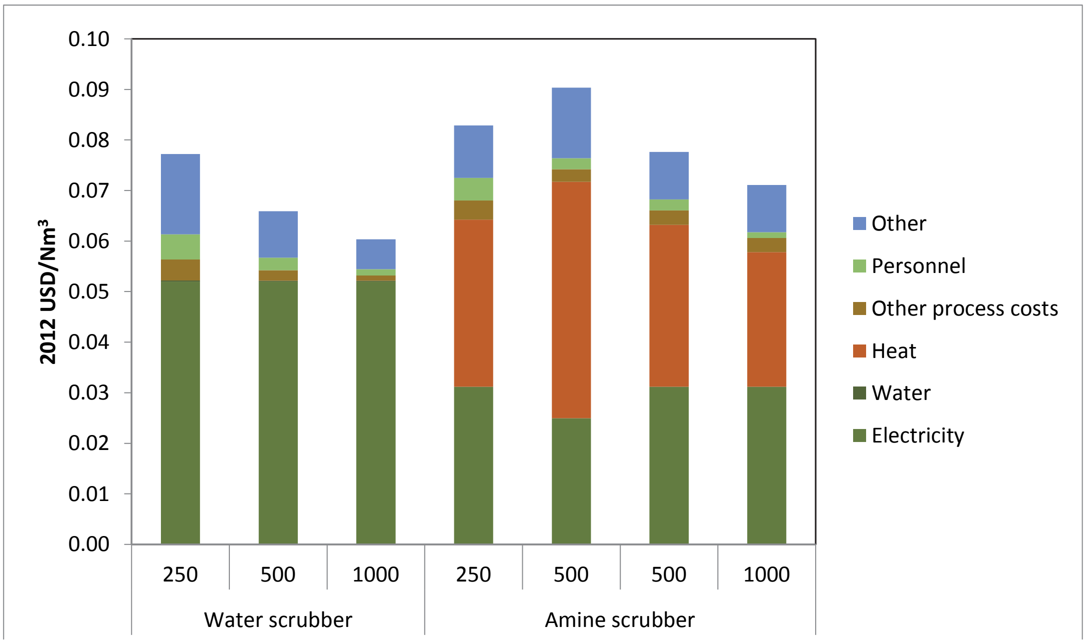


Figure 6.5: Operating costs for biogas upgraders by type and size

Source: Urban, 2009.

6.3 Total biogas production costs to produce biomethane for vehicles

The total production costs for upgraded biomethane suitable for use in vehicles are lowest for systems based on wastes or sewage, where feedstock costs are non-existent and capital costs are low. Biomethane upgraded for use in vehicles can be produced for between USD 0.45 to USD 0.55/lge from wastes or sewage (Figure 6.6), but this range increase to USD 0.65 to USD 0.75/lge when some maize silage is also purchased. Large-scale production will, however, require the purchase of feedstocks (e.g. maize silage) for the majority of the throughput. It will therefore be more expensive, even after taking into account the economies of scale from moving to higher production capacities.

When maize silage is the primary feedstock, production costs for biomethane will be between USD 0.73 and USD 0.93/lge when water scrubbers are used to upgrade the raw biogas and between USD 0.75 and USD 0.87/lge when amine scrubbers are used.

There is little difference between the amortised capital and operating costs of the two upgrading systems examined. The most recent data suggests that upgrading systems based around water scrubbers will be somewhat cheaper than amine scrubber systems for capacities up to 1 000 Nm³/hour raw biogas processing capacities (Bauer, 2013). However, cost differences become very small at higher capacities, and the key factor determining a choice will be the technical performance of the system depending on the biogas composition and the biomethane quality requirements.

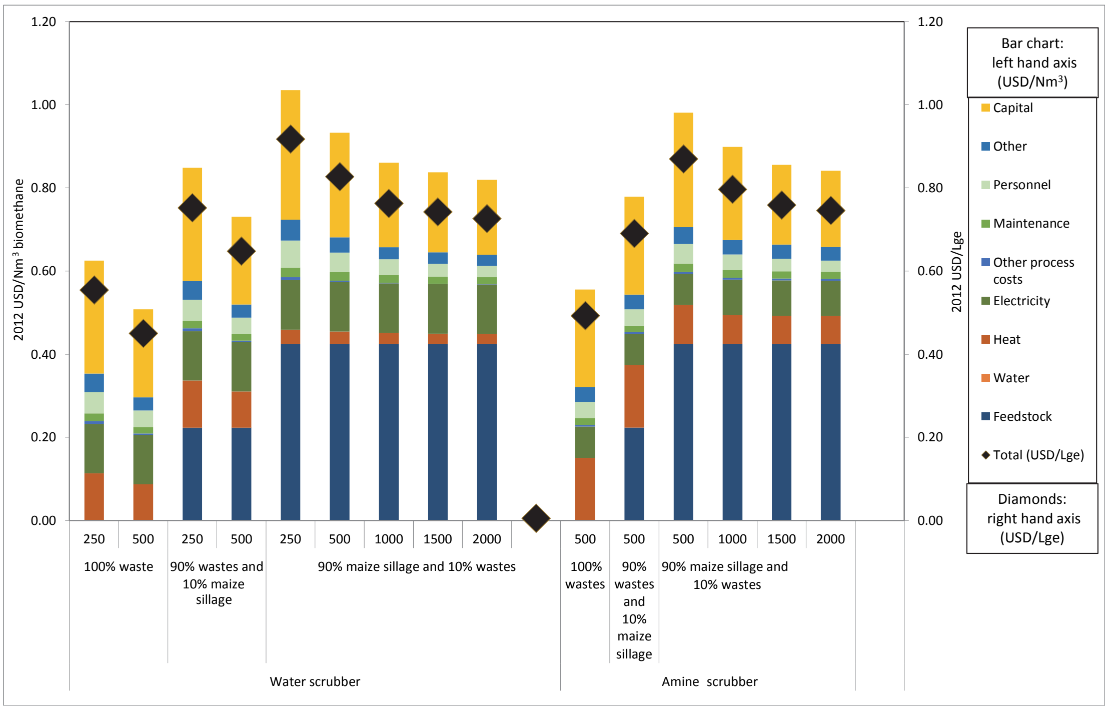


Figure 6.6: Total production costs for biomethane suitable for vehicle use by upgrader type and size

Sources: IRENA analysis; Urban, 2009; and Bauer, 2013.

7 ELECTRICITY FOR TRANSPORT

The use of electricity from renewable sources as the energy source for vehicles is another option to decarbonise the fuels used in the transport sector. In addition to decarbonising transport fuel use, electrification of the vehicle fleet has significant local environmental and health benefits, as electrification will also reduce local pollutant emissions.

There is a continuum of options for the electrification of vehicles (Figure 7.1). A vehicle that relies 100% on electricity (from either the grid or an off-grid source) for motive power is referred to as an electric vehicle (EV) or sometimes a battery electric vehicle (BEV).[38] An EV dispenses entirely with the internal combustion engine, and a battery pack supplies electricity to an electric motor, or motors, to convert the electricity into mechanical power. The battery also provides all the auxiliary power required (e.g. lights, air conditioning).

In the middle of the spectrum of electrification options for a vehicle (Figure 7.1) lie PHEVs. These have a smaller battery than EVs and are plugged into the grid to charge the battery. They combine an often downsized ICE with the capability for all-electric driving in charge depleting mode. PHEVs can be charged from the grid and have sufficient battery storage and powertrain designs to allow pure electric operation over a certain distance depending on driving patterns and battery size. The ICE provides power when the battery has reached its minimum discharge level or under certain driving conditions. With significant deep discharging and charging, the batteries need to be more robust than light hybrid configurations and even EVs. As a result, R&D into extending the battery life of PHEVs is a very important cost reduction strategy.

PHEVs can be set up with "series" or "parallel" configurations. In the parallel configuration either the electric motor or the ICE can drive the vehicle, or both where extra power is needed. In the series configuration, the drive system becomes pure electric and the ICE is used only to charge the battery.

The distance that a PHEV can travel on the battery alone is usually used to categorise the degree of electrification. Thus a PHEV40 is a PHEV with a range of 40 km on the battery only. This type of vehicle configuration will often allow the majority of driving to be done on electricity from the battery alone. Meanwhile, the retention of an ICE means that the total range of the vehicle on electricity and liquid fuels is comparable to today's ICE

38 For simplicity, in the rest of this report these types of vehicles are referred to as EVs.

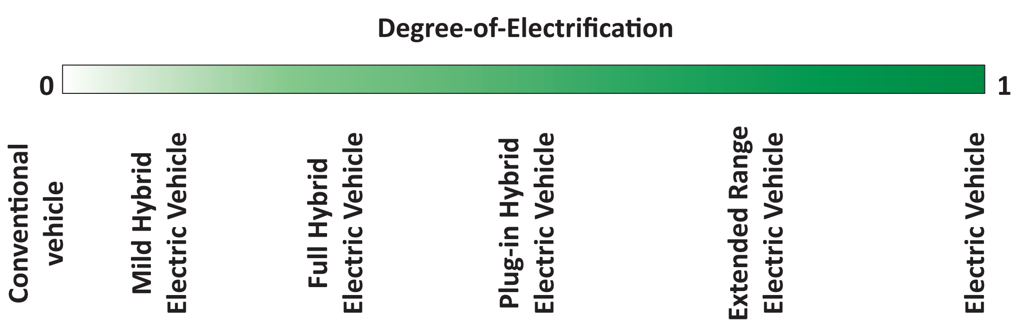


Figure 7.1: The range of electrification options for vehicles

vehicles. The size of the battery required to achieve a given electric driving range will depend on the size and weight of the vehicle.

A delicate equilibrium needs to be found to determine the optimal battery chemistry and size. The need for high power, acceleration and optimal regenerative breaking has to be balanced against large energy storage requirements (i.e. a high specific energy density) that increases the vehicle range.

7.1 Battery cell and pack costs and characteristics

Lithium ion (Li-Ion) battery chemistry represents the technology of choice for electric vehicles today and for the forseeable future. Li-Ion batteries have overtaken nickel-metal hydride (NiMH) batteries because of their better specific energy and power density qualities. The relationship between power delivery and specific energy density is very important for the performance of the vehicle. Figure 7.2 maps the specific power density relative to specific energy density for different electricity storage options. The fact that Li-Ion batteries are to the right of the frontier of options shows why they have become the focus of PHEV and EV battery development.[39]

39 Ongoing research is focused on new battery technologies with significantly improved performance compared to today's Li-Ion batteries' specific energy densities and power outputs. These performance improvements are needed to allow EVs to go mainstream; an EV with today's battery technology with a 400 km range would have twice the kerb weight of a conventional ICE vehicle (NPC,2012).

Li-Ion batteries come in a range of different chemistries, so the term Li-Ion battery refers to the Li-Ion family of battery chemistries that induce lithium ions to move between the anode and cathode in a battery.

Within the family of lithium-ion battery chemistries, each specific technology usually has a number of tradeoffs between power density, specific energy density, safety, cycle life and performance, and costs (Table 7.1). The original Li-Ion chemistries developed for consumer applications have proven too expensive for automotive uses, given their large share of the total cost of the vehicle. This has spurred the development and deployment of alternative, cheaper Li-Ion chemistries with more suitable thermal characteristics better adapted to automotive applications. These include lithium-iron-phosphate (LFP), lithium-manganese-oxide spinel (LMO), and nickel-cobalt-aluminium (NCA) (NPC, 2012). To date, no dominant chemistry has emerged, but deployment for automotive applications is still in its infancy and further experience will prove invaluable in improving performance and reducing costs.

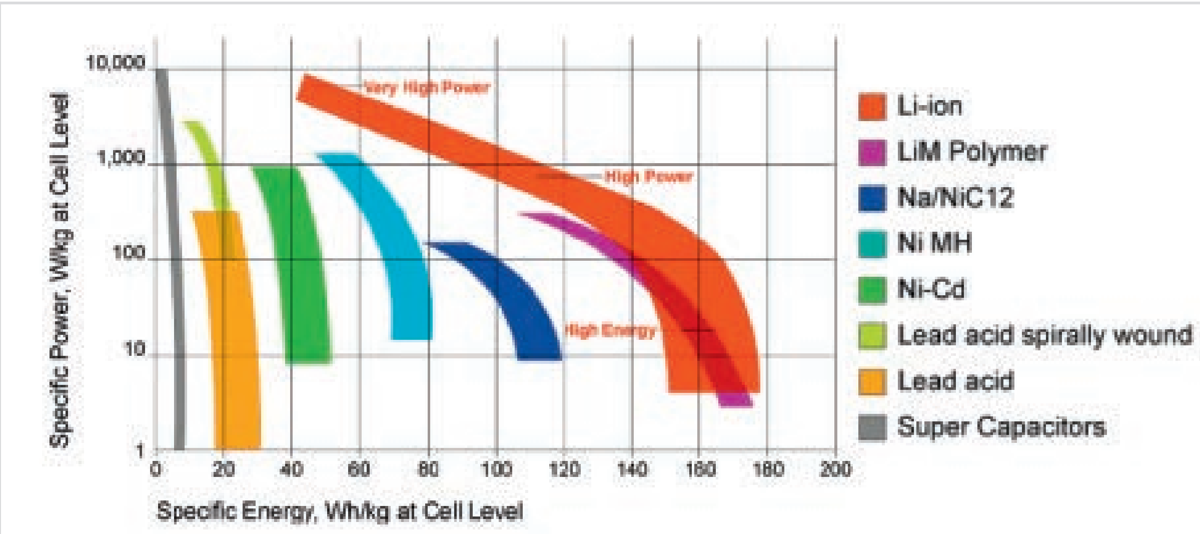


Figure 7.2: Specific power versus specific energy density for different electricity storage solutions

Source: based on Johnson Controls, published in NPC, 2012.

Table 7.1: Li-Ion battery characteristics by chemistry

Cathode	Anode	Energy Density	Power Density	Cycle Life	Safety	Cost
Lithium cobalt oxide	Graphite	High	Fair	Fair	Fair	High
Nickel cobalt aluminum oxide	Graphite	High	High	Fair	Fair	High
Lithium iron phosphate	Graphite	Low	High	High	Very Good	Fair
Lithium manganese oxide	Graphite	High	High	Fair	Very Good	Fair
Lithium manganese oxide spinel	Graphite	High	High	Fair	Good	Low
Lithium manganese oxide spinel polymer	Graphite	High	High	Fair	Good	Low
Manganese nickel cobalt oxide	Graphite	High	Fair	Low	Fair	High
Lithium manganese oxide spinel	Lithium titanate oxide	Low	Low	High	Good	High
Lithium nickel oxide	Graphite	High	Fair	Fair	Fair	Fair
Lithium manganese nickel oxide spinel	Graphite	High	High	Fair	Fair	Low
Lithium manganese nickel oxide spinel	Lithium titanate oxide	Fair	High	High	Good	Low

Source: NPC, 2012.

The key parameters a vehicle designer must take into account when considering a battery are costs, the specific energy density of the battery and the relationship with power charge and discharge. The specific energy density can be measured in two ways; either in terms of energy per unit mass (e.g. Wh/kg) or volume (e.g. Wh/litre). Depending on the design constraints, one metric will be more useful than another. For light-duty vehicles, weight is always an issue, but for PHEVs where space is at a premium, density per unit of volume may be the main consideration.

An additional complication for vehicle manufacturers is that battery cell performance in terms of specific energy density is higher than the overall battery pack density. This is due to the additional weight of the protective casing, thermal energy management systems and controls. In the recent past, the additional load from these components would double the weight of the battery pack from the battery cell weight, thereby halving the specific energy density (NPC, 2012). Further R&D and deployment should help to reduce this weight burden.

In addition to battery costs, the estimated economic battery life is critical to determining the overall cost of driving an electric vehicle. Battery performance degrades over time with the number of cycles (charge/discharge cycles) performed. Maximising the number of cycles a battery can perform before it deteriorates to a point it needs replacement will significantly enhance the economics of PHEV and EVs. To maximise the life of a battery, the swing in the state-of-charge (SOC) is typically limited to 40-80%. Thus the effective cost of electricity available for driving is higher than the nameplate cost, as only 40-80% of the battery charge is made available. For instance, a battery pack that costs USD 500/kWh, but that charges and discharges over only 60% of its capacity would have an effective cost of USD 833/kWh.

The other key operational area for maximising battery life is the thermal energy management system for the battery. The main problem is that battery life is significantly reduced for Li-Ion batteries when the battery operates at high temperatures. Ensuring the battery temperature remains as close to design goals as possible is therefore essential if battery life is to meet expectations. Most PHEVs today use a liquid thermal energy management strategy, but this is expensive. Some use cheaper forced air systems, notably the Nissan Leaf and Mitsubishi "I". In contrast, very cold temperatures do not have a significant impact on battery life, but do have a significant impact on the power availability of the battery. The significantly reduced power availability will limit acceleration, top speed and vehicle range. This is an important issue for EVs that rely exclusively on their battery for power. It is less of a problem for PHEVs because the ICE can be used to offset the lack of battery power. The thermal energy generated from battery operation can be used to raise the operating temperature when using a smart battery thermal management system, rather than rejecting the heat. However, for EVs this may need to be supplemented by an alternative source of heat prior to operation or during operation.

All these variables will interact with driving patterns and charging patterns to produce a wide range of operating profiles for the charge/discharge cycles of a PHEV or EV battery pack. Although Li-Ion batteries have been shown to be able to achieve 4 000 to 5 000 deep cycles in the laboratory and 1 000 in commercial operation, it is difficult to translate this into mileage. However, vehicle manufacturers are moving to remove this uncertainty from consumers and offering battery warranties or battery leasing options to transfer the risk from the owner of the vehicle.

The estimate of battery pack costs for EVs in 2012 varies quite widely depending on the literature, but is typically USD 500-800/kWh (Reuters, 2012; BNEF, 2012; McKinsey, 2012; Element Energy, 2012a; and IEA, 2013). The average battery cell costs are USD 400/kWh, but they vary widely depending on the scale of production. The build-up into battery packs adds 50-100% to the cell costs (Element Energy, 2012a).

The total cost for a battery pack with a capacity of 22 kWh for a mid-size EV is dominated by the battery cells themselves, which account for just over half of the total cost (Figure 7.3). The balance of the costs are split between a range of components, with only the margin and warranty share exceeding 10% of the total.

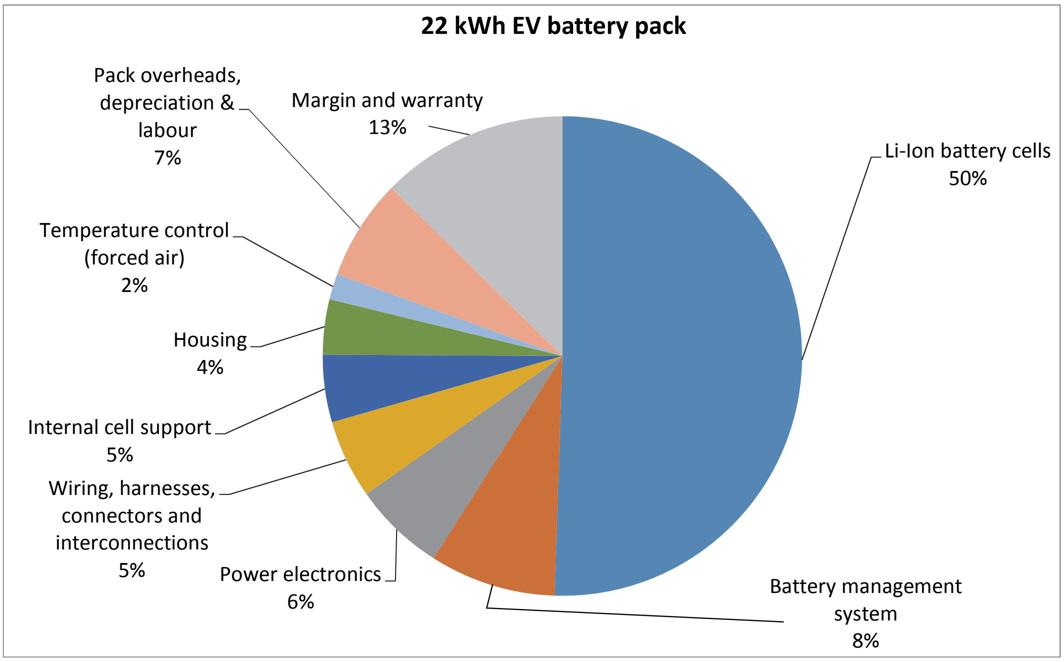


Figure 7.3: Total cost breakdown for a 22 kWh Li-Ion battery pack for a 100% electric EV, 2012

Source: Element Energy, 2012.

The battery packs for PHEVs can be twice, or even three times as expensive per kWh of storage for small batteries, than the battery packs of EVs (Figure 7.4). Due to their higher power performance, the battery cells themselves carry a price premium of around 30% per kWh compared to larger EV batteries (Element Energy, 2012a). The smaller size of PHEV batteries also tends to raise the percentage difference for the balance of system costs for the battery pack. Finally, the battery management system is significantly more expensive. This is because it requires greater flexibility (more sophistication and components) to shift energy to and from the battery more regularly and in a wide range of operating modes. There is also a need to more actively manage the battery cells and state of charge. All these factors increase the specific cost of the battery pack relative to that of an EV. The main advantage of PHEVs, that of smaller battery packs, is therefore offset to quite a large degree by these higher unit costs.

7.2 Total incremental PHEV and EV vehicle costs and the cost of vehicle ownership and operation

The incremental vehicle costs for PHEVs and EVs are dominated by the cost of the battery pack. However, the electric motor and generator, as well as the power electronics, converter and inverter also create significant incremental costs. The cost of gasoline saved will vary depending on the incremental cost compared to an equivalent vehicle, the battery life and annual mileage.

PHEV incremental costs and the cost of gasoline saved

PHEVs are only just taking to the road in any significant numbers. Costs are still uncertain and will fall over time as deployment accelerates. The total incremental cost of PHEVs is dominated by the cost of the battery, particularly for high all-electric driving ranges (Figure 7.5). For a PHEV with a 16 km range, the battery pack is estimat-

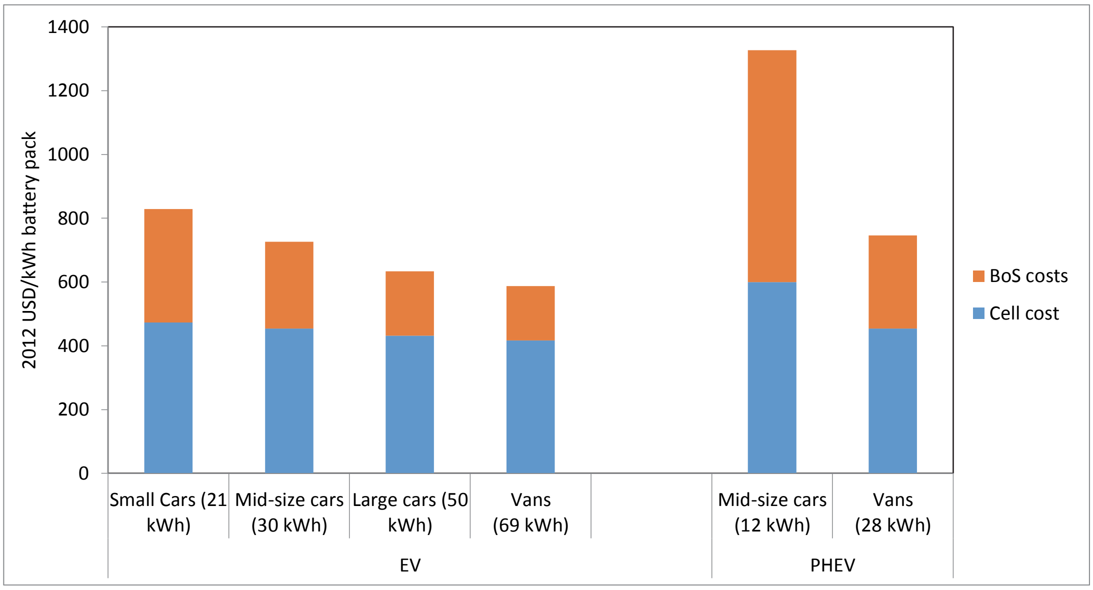


Figure 7.4: Total cost breakdown for Li-Ion battery packs for EVs and PHEVs by vehicle class, 2012

Note: *Assumes a maximum 80% of the EV battery is used in charge/discharge cycle and 70% for the PHEV batteries.*

Source: Element Energy, 2012a.

ed to account for around 45% of the gross[40] incremental costs over an equivalent conventional ICE vehicle. For a PHEV with a 65 km range, the battery costs increase to 72% of the gross incremental cost.

The incremental vehicle costs and the cost of gasoline saved for production series PHEVs are presented in Figure 7.6. The incremental vehicle costs are based on manufacturer's recommended retail prices as of March 2013. In most cases, even where PHEVs are based on existing models, specifications can be very different, and making an exact comparison on a like-for-like basis is difficult. Where multiple specifications of the PHEV or the base model are possible for comparison, the high and low incremental costs are provided.

Of the models available, the Toyota Prius has the smallest battery and lowest all-electric range (around 18 km)[41], while the Chevrolet Volt, an extended range electric vehicle, has the greatest all-electric range (around 56 km). Taking the average driving patterns of the United States, Europe and Japan and restricting charging only to the home results in the all-electric range of the Prius being estimated to cover around 30% of vehicle kilometres in the United States and around 45% in Japan over the course of a year. Meanwhile, the Chevrolet Volt would cover around 65-90% of annual vehicle kilometres. Charging at work or anywhere else would raise these values significantly.[42]

The average cost of gasoline saved by the PHEV varies depending on the amortised additional annual capital cost and additional electricity expenses. These costs are determined by the incremental vehicle costs, discount rate, electricity and gasoline prices, and fuel efficiency of the incumbent technology. The cost of the gasoline saved is close or less than the retail price for the Ford, Honda and Chevrolet offerings compared to a similar non-PHEV model from these manufacturers. This assumes average gasoline prices of around USD 2/litre in 2012 in Europe and Japan. The challenge facing Toyota, Mitsubishi and Volvo is that the base model against which their products are compared is already relatively fuel efficient. This means the incremental costs are apportioned over relatively lower fuel savings. A comparison against the best in class fuel efficiency would therefore raise the cost of gasoline saved for the Chevrolet and Ford. However, it is more open to interpretation.[43] In the United States, where gasoline costs in 2012 averaged around USD 1.3/litre, the hurdle for competiveness is much higher.

40 Before any cost savings from switching to a plug-in hybrid configuration.

41 In fact, for the Prius some gasoline consumption occurs even within this "all-electric" range and this also maybe the case for other models, depending on driving styles.

42 For instance, a 65 km all-electric range vehicle in the United States would see its all-electric share of annual vehicle km based on average driving patterns increase from around 65% with just home charging to 73% with charging at work and home, to 80% for charging everywhere (NPC, 2012).

43 This type of analysis is not presented here given the difficulty in identifying comparable specifications for the "best in class" fuel efficiency model relative to the PHEV model from a different manufacturer. What is clear is that this would raise the cost of gasoline saved for the Ford and Chevrolet PHEVs.

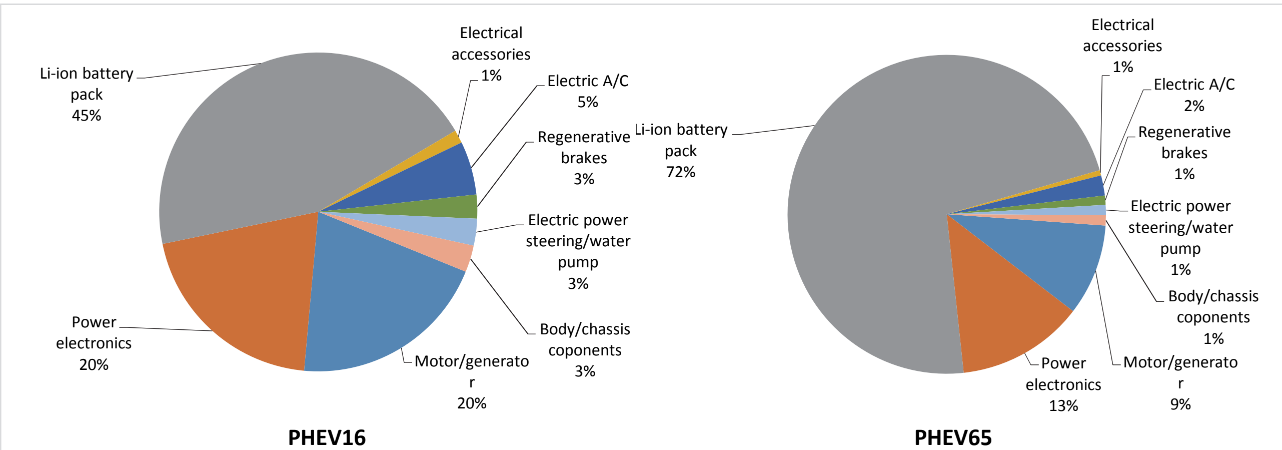


Figure 7.5: PHEV gross incremental cost breakdown for all-electric ranges of 16 km and 65 km

Source: NAS, 2010.

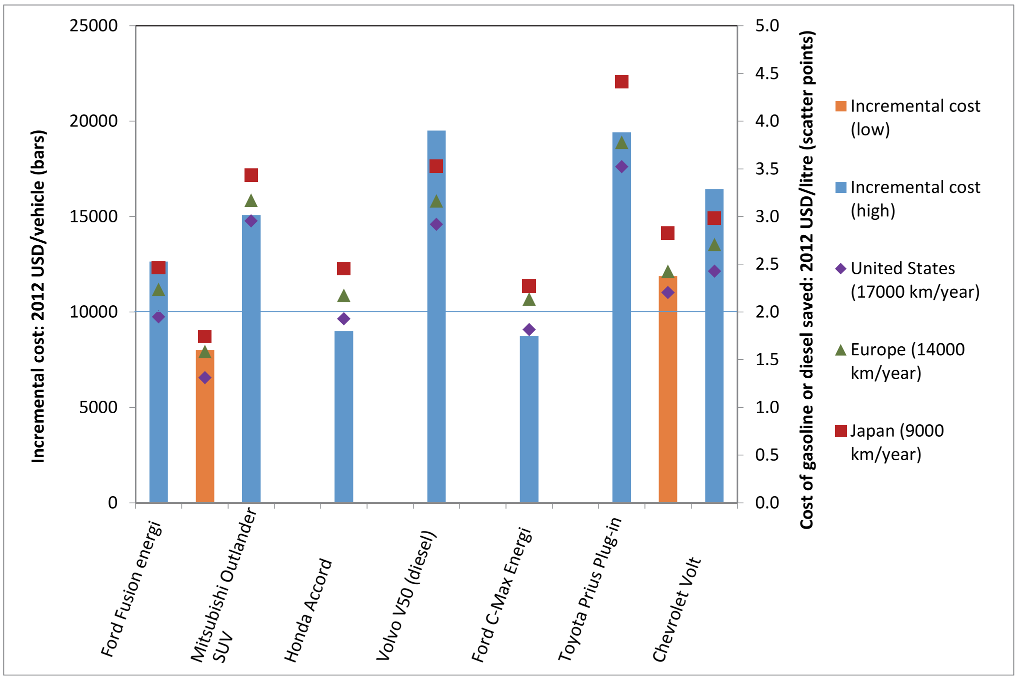


Figure 7.6: PHEV incremental costs and cost of gasoline saved

Note: *Fuel consumption calculations were based on U.S. testing cycles for all PHEVs, except the Mitsubishi and Volvo, which are based on European testing cycles. The share of all-electric operation based on all-electric range from U.S. and European testing cycles and vehicle travel profiles was converted to a percentage of total travel. This used data from VMCC (quoted in Niste, 2012) and NPC, 2012. Average annual travel for the U.S. was 17 000 km, 14 000km for Europe and 9 000 km for Japan. Battery life is assumed to be 160 000 km. These assumptions provide indicative average point estimates and are not definitive.*

Source: EPA, 2013; Eurostat, 2013; fueleconomy.gov, 2013; World Bank, 2013; manufacturer's technical specifications and MSRP as of May 2013 (Europe for Volvo and Mitsubishi, U.S. for the rest); Niste, 2012; and NPC, 2012.

EV vehicle costs and annualised costs of ownership

Pure EVs that rely 100% on batteries for their energy source and receive only electricity from the grid or regenerative breaking require larger battery packs to reach acceptable range levels. This significantly increases the cost of the vehicle. However, compared to PHEVs, the pure EV battery packs are cheaper per kWh resulting in relatively lower incremental costs over a conventional vehicle than for a PHEV for the equivalent battery size. There are also some cost reductions from some parts that are redundant when shifting from an ICE to an all-electric vehicle (e.g. the ICE, fuel tank and system, exhaust system). However, the net result is a significant increase in costs over what an equivalent model would cost.

Table 7.2 presents the manufacturer's suggested retail price (MSRP), range and the calculated or estimated electric efficiency of the vehicle. Only EVs in production and available for purchase by the general public have been included in Table 7.2; vehicles available in limited numbers to fleet customers have been excluded.[44]

These prices represent a significant premium over an equivalent ICE-powered vehicle, but the all-electric drive is around three times as efficient as an ICE. Meanwhile, electricity prices can also be cheaper than gasoline or diesel depending on the country. In order to compare the relative economics of EVs and conventional vehi-

44 These vehicles are typically leased to the fleet owners, so costs are not well known and they generally represent technology demonstration or proving programmes.

Table 7.2: Electric vehicle prices, range and on-road efficiency

	Cost *(2012 USD)*	Range *(km)*	Battery lease/ month *(2012 USD)*	Efficiency *(kWh/km)*
Mahindra e2o	15 800-16 600	100		0.10
Roewe E50	37 590	120-190		0.11
Renault Zoe (battery lease)	26 910	210	103	0.15
Tesla Model S (premium 85 kWh)	95 400-105 400			0.24
Renault Fluence Z.E. (battery lease)	33 930	160	125	0.14
Ford Focus Electric	39 200	122		0.2
Bolloré Bluecar	24 700	250		0.12
BYD e6	52 140	310		0.22
Mia Electric L (purchase)	39 630	125		0.10
Mia Electric L (battery lease)	27 020	125	140	0.10
Smart electric drive	25 000-28 000	109		0.20
Nissan Leaf	35 200-37 250	117		0.21
JAC J3 EV	25 000	130		0.14
Mitsubishi iMiEV U.S. (Peugeot iOn and Citroën C-ZERO)	29 125	99.2		0.19

Note: *Data for vehicle prices (MSRP) and electric range are from the manufacturer's website or www.fueleconomy.gov as of May 2013. On-road efficiency is taken from www.fueleconomy.gov or the New European Driving Cycle calculations. For vehicles not sold in the United States or Europe, manufacturer data has been used.*

Sources: www.fueleconomy.gov, 2013 and manufacturer websites.

cles, a different approach is required from that used for PHEVs. Instead of estimating the cost of gasoline saved, the EV evaluations are based on the annualised cost of ownership for 160 000 km. This lifetime was used given it is the average for the current warranty offerings by the vehicle manufacturers for the Li-Ion batteries powering this generation of EVs. The number of years over which the capital costs are spread will therefore depend on annual vehicle use. However, it represents just over nine years based on the average annual vehicle use in the United States, over 11 years in Europe and almost 17 years in Japan.[45]

Figure 7.7 presents the average annual cost of ownership of EVs currently on the market in the United States, Europe, Japan, China and India. Most of these EVs are new, original designs by their manufacturers, and a direct comparison with an ICE-powered direct equivalent is not possible. However, this can be done with the Smart, Fiat 500 and Ford Focus, although specifications across models are not an exact match and performance will differ. The results are similar to what was seen for PHEVs. Where the base model is not the most fuel efficient in its class, EVs look particularly attractive, even with today's low-production volume models. However, where the base model is relatively fuel efficient, the additional costs of the EV are not recovered within the 160 000 km assumed for this economic comparison.

45 Average annual vehicle use in the United States is estimated to be 17 000 km/year, 14 000 km/year in Europe and 9 000 km/year in Japan. However, vehicles are typically not owned from new till 160 000 km by average new vehicle purchasers, and these vehicles are likely to be sold significantly before the battery life is met, particularly in Japan and Europe.

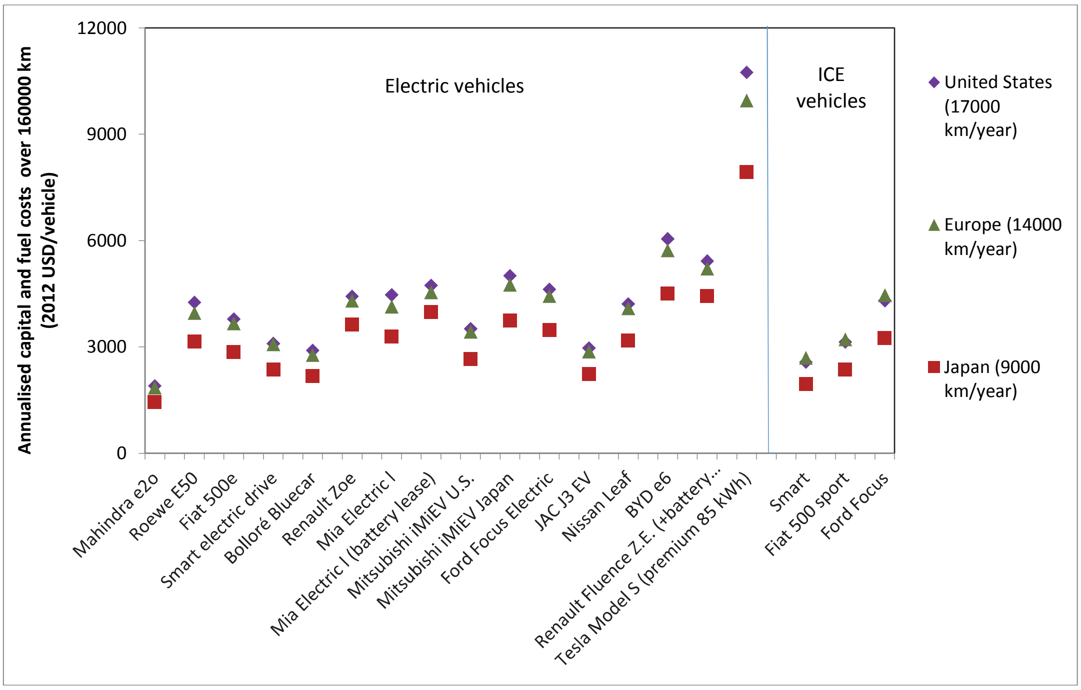


Figure 7.7: Annualised costs of ownership (vehicle depreciation and fuel costs) for electric vehicles over 160 000 km

Note: *Analysis is based on MSRPs and efficiency for the main market in which it is currently available. The average cost of capital is assumed to be 10%, and residual value for the vehicle 30% of the MSRP after 160 000 km. Values for different regions are based on varying annual vehicle use and fuel prices. It is assumed MSRPs would remain the same. Results are therefore indicative of annualised running costs. Insurance and maintenance costs are not considered.*
Sources: Table 7.2 for vehicle costs and fuel consumption, World Bank, 2013; Eurostat, 2013; and IEEJ, 2013.

Box 7.2: Electrification of freight vehicles

Biofuels can be used in the gasoline and diesel internal combustion engines in short, medium and long haul road freight vehicles. Electrification of freight sectors is more challenging, as battery packs are not going to be able to provide the required range for medium- to long-haul freight vehicles. Electrification of these sectors in the longer term may be feasible through overhead electrification, similar to that used for trams and many rail systems, over fixed routes, or through the roadway using inductive power transfer (wireless). However, these are options for beyond 2020 and are therefore outside the scope of this report.

However, the electrification of light commercial vans and trucks could be attractive in the medium term. Figure 7.8 presents the estimated costs for a conventional ICE van and for PHEVs and EVs. Small plug-in hybrid vans are estimated to cost twice that of their conventional equivalent, and pure electric vans 2.4 times as much. However, by 2020 this premium could decline to just 40% for plug-in hybrids and around 85-90% for pure electric small vans. Larger "panel" vans (small trucks of 2.6-2.8 tonnes) have similar estimated incremental costs for plug-in hybrids today, but pure electric panel vans require significantly larger batteries to maintain payload and range. They also have capital costs 3.2 times greater than a conventional ICE panel van. By 2020 these incremental costs could decline to 40% for a plug-in hybrid panel van and 120% for a pure electric panel van.

These cost reductions mean the total ownership costs over four years of a small plug-in hybrid van could decline to a level only 15% greater than the equivalent ICE. The pure electric small van would have total ownership costs of around a quarter more than the ICE version over four years. The additional total ownership costs of panel vans in 2020 are estimated to be 10% more for a plug-in hybrid and 38% for a pure electric van (Element Energy, 2012b).

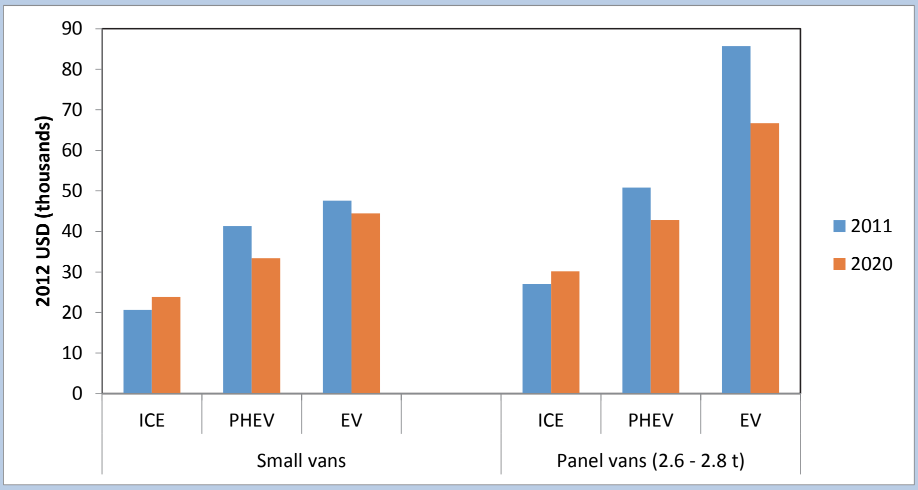


Figure 7.8: Vehicle costs for ICE PHEV and EV small vans and panel vans

Source: Element Energy, 2012b.

EVs are only just taking to the road in significant numbers, Figure 7.7 highlights that the economics of some offerings are already competitive or close to competive with an equivalent conventionally powered ICE vehicle. When using electricity generated by renewables GHG emissions are significantly reduced. However, the most significant co-benefits of PHEVs and EVs will quite possibly be the elimination of local pollutant emissions and the resulting improvements in local air quality. To whatever extent these societal benefits are incorporated by policy makers, they will improve the economics of these vehicles.

As charging infrastructure grows and consumers fear of range issues are assuaged by experience with EVs, favourable support policies should see an acceleration in deployment and corresponding cost reductions for EVs, particularly from improvements in battery technologies and the mass production of battery packs. EVs are therefore likely to become an increasingly competitive solution to reducing the reliance on fossil fuels in the light vehicle sector. Electrification of transport in conjunction with increasingly high shares of renewables in power generation will reduce not only local pollutants but global GHG emissions as well.

7.3 EV vehicle infrastructure investments and the annualised costs of ownership

The analysis presented here is based on home charging only, this yields a conservative estimate of the percentage of vehicle kilometres that will be covered by PHEVs. For the widespread adoption of EVs, additional charging infrastructure is likely to be required to remove consumer uncertainty about range issues, at least with the likely battery technology performance in the short- to medium-term.

The charging of electric vehicles is not completely standardised. The Society of Automotive Engineers (SAE) has defined three levels of charging related to the circuit rating and power of the charging system (Table 7.3). However, an alternative way of considering charging that is more pertinent from an electricity system operator perspective is also possible. EURELECTRIC has laid out their categorisation related to the power and current delivery (AC or DC) (Table 7.3).

Level 1 and normal power charging can rely on existing residential or commercial power circuits. It may not require additional investment, either in the home or for the distribution network, if EV deployment can be scheduled into existing investment plans (AECOM, 2009), but provides the slowest charging rate. Level 2 charging and medium power charging requires addi-

Table 7.3: Electric vehicle charging infrastructure costs

	Mains connection/ circuit rating	Power *(kW)*	Power *(Amps)*	Indicative recharge range per hour *(km)*
SAE				
Level 1*	120V-240V	2.4	10-20	12
Level 2	240V	19.2	80	96
Level 3	480V 3-phase	192	400	960
EURELECTRIC				
Normal power	1-phase AC	≤ 3.7	10-16	<20
Medium power	1 or 3-phase AC	3.7-22	16-3	20 – 110
High power	3 phase AC	> 22	>32	>110
High power	DC	> 22	>32**	>110

Note: * *Voltage and amps for residential/commercial electricity circuits is country specific.*
** *This will vary depending on the batteries' DC voltage rating and the power of the charger.*

Sources: AECOM, 2009 and EURELECTRIC, 2011.

tional infrastructure in the home, at work or public parking spaces. In the home or work parking spaces, these charging points may cost between USD 1 000-1 300 each (AECOM, 2009 and NREL, 2013). In public spaces or work parks without existing electrical infrastructure these dedicated charging points may at present cost between USD 4 000-9 000 (AECOM, 2009; Chang, 2012 and NREL, 2013) per charging point.[46] However, this should decline over time. In addition, these may require 3-phase power in the home and a corresponding increase in local distribution network capacity to cope.

High power AC or DC fast charging points are significantly more expensive, and costs range from USD 10 200-50 000 installed (Nemry and Brons, 2010; and Wirges, 2012). They will also tend to shorten the life of the PHEV or EV battery.

The simulation for the Stuttgart region to 2020 (Wirges, 2012) analyses the number and location of charging stations required to support the significant deployment of EVs. Based on a detailed modelling of the location, driving patterns and ownership of EVs, the analysis demonstrates that relatively few public charging locations are required in the base case for EV expansion. However, a higher quota for public charging stations to help accelerate deployment does not have a huge impact on the required number of charging points. The deployment of charging points over time follows an exponential trend.

Table 7.4 presents the results of the increase in annual ownership costs, assuming a 10% cost of capital and a 15 year life for the charging equipment. The results assume that level 2/medium power charging points in the home or in work car parks with access to electricity infrastructure in close proximity requires total installation costs of USD 1 150 on average between now and 2020. For public charging points costs are assumed to average USD 6 000 including all installation works. For work car parks where electricity infrastructure is not closely available or suitable (as in the case of most outside parks), USD 6 000 per charging station is also assumed. Although costs may be lower than this on average for a large-scale roll-out, this is not yet clear. Given most employment occurs in small- to medium-sized businesses, hence limiting the scale of individual projects, this conservative assumption is used. Maintenance costs for the workplace, public and fast charging stations are assumed to average USD 200/year through to 2020.

Table 7.4 presents the results for two cost pathways. The low cost pathway assumes that 75% of home charging points are level 1/normal power connections with no incremental costs. It also assumes 75% of workplace charging stations are placed in car parking areas with ready access to electricity infrastructure and hence have the lower costs identified above. In the high cost pathway, the share of these low cost options is only 25%.

46 The lower value is for a charging station with ten connections, significantly helping to amortise costs.

Table 7.4: Electric vehicle charging infrastructure investment needs in 2020 for the Stuttgart region for low cost and high cost pathways

	Charging stations	Low cost pathway		High cost pathway	
		Investment *(2012 USD million)*		Investment *(2012 USD million)*	
		Base EV scenario	More public charging	Base EV scenario	More public charging
Home	21 851	12.6	12.6	18.8	18.8
Work	16 268	58.2	58.2	77.9	77.9
Public	478/1 678	2.9	10.1	2.9	10.1
Fast	94/240	1.4	3.6	1.4	3.6
Total		75.0	84.4	101.0	110.4
		2012 USD/vehicle			
Annualised cost of charging infrastructure		256	288	345	377
O&M costs		96	104	96	104
Total annualised cost		352	392	441	481

Note: *In the column for charging stations the number before the slash is for the Base EV scenario and after the slash for the more public charging point scenario.*

Sources: Based on Wirges, 2012 and IRENA analysis.

As can be seen, the average annualised costs of infrastructure requirements add an average of between USD 350 to USD 480/vehicle. This represents an average annualised ownership costs increase for fuel and vehicle purchase costs analysed in Figure 7.7 of 6-25% in 2020 for the lower value for infrastructure costs and

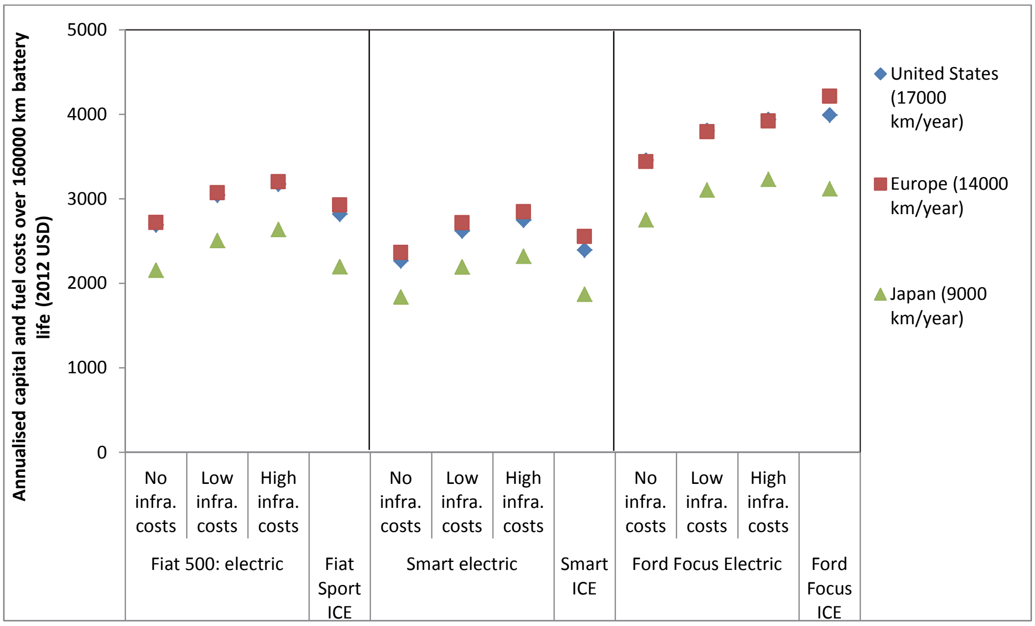


Figure 7.9: Annualised costs of ownership (vehicle depreciation and fuel costs) in 2020 for electric vehicles over 160 000 km including charging infrastructure costs

Note: *Analysis is based on Figure 7.7 and Table 7.5.*

9-35% in 2020. (See Figure 8.2 for the total annualised ownership costs in 2020 without the infrastructure costs).

The impact of the increase in the annualised costs of EVs for which direct comparisons with an ICE equivalent are possible are presented in Figure 7.9. For small, relatively efficient ICE vehicles, the additional infrastructure charging costs are an issue that could slow the competitiveness of EVs. For larger, less fuel-efficient ICEs, average charging infrastructure costs by 2020 still result in EVs being competitive with a fossil fuel equivalent. However, this is apportioning average costs to each vehicle owner. In reality, vehicle owners will be able to choose the level of charging infrastructure they access and hence the costs they face. Figure 7.7 reflects most EV owners accessing charging with level 1/normal power charging points that require little or no incremental costs. Figure 7.9 represents the case where vehicle owners access a wider range of charging points, although still predominantly at work or at home. These scenarios are consistent with the assumption that PHEV and EV deployment is focused on urban users and the predominantly short journeys that dominate their total annual vehicle kilometres.

8 Outlook for costs to 2020

The renewable options for road transport are diverse and at different stages of technological and commercial maturity and deployment. The outlook for the costs of each one to 2020 is therefore wide. Conventional biofuels are based on mature, commercially proven technologies, but the costs of production are at the mercy of movements in their food-based feedstock world prices. Advanced biofuels and electric road vehicles are only just beginning to be deployed at commercial-scale. Production is only just scaling up so their cost reduction potential is good. Biomethane for transport is somewhere in between these extremes. It benefits from a mature production technology but limited feedstock availability for low cost production (e.g. waste streams) and relatively little deployment of upgrading facilities from biogas to biomethane.

The rate of deployment to 2020 for advanced biofuels as well as PHEVs and EVs will be crucial to the amount of learning cost reductions that will occur by 2020. The analysis in the following sections assumes that deployment accelerates for these technologies sufficiently to reach the goals for cost reduction identified in the literature. It is important to note that these rates of deployment are ambitious and will not be achieved without continued policy and, in some cases, accelerated policy support.

8.1 Outlook to 2020 for liquid biofuels and biogas costs

Conventional liquid biofuel costs are projected to rise to 2020 as the result of increases in feedstock prices. Analysis by OECD-FAO into the outlook for the agricultural sector to 2020 predicts corn price increases of only around 1% between 2012 and 2020, but a 25% increase in the cost of sugar cane in Brazil (OECD-FAO, 2012). Wheat prices are expected to increase by a more modest 11% between 2012 and 2020, while vegetable oil prices are projected to increase by around 10%. This could see grain-based conventional biofuel production

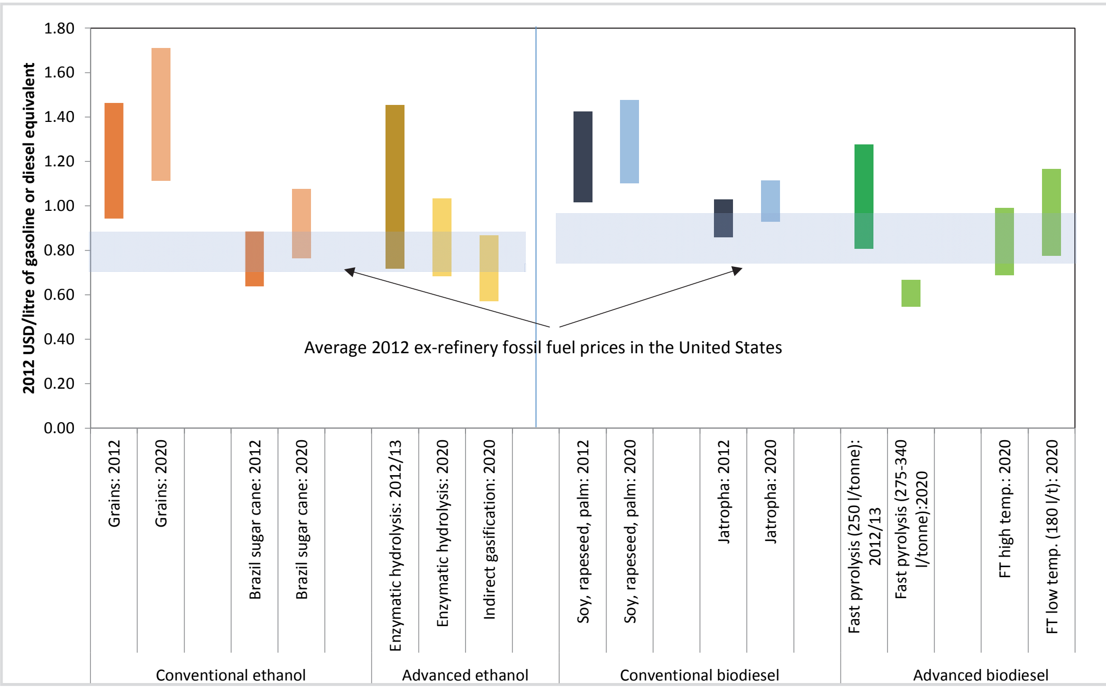


Figure 8.1: Summary of conventional and advanced biofuel production costs, 2012 and 2020

Sources: See sections Four, Five and Six.

costs increase by 1-9%, while production costs for ethanol from sugar cane in Brazil could increase by 20-22%. The production costs of biodiesel from vegetable oils may increase by around 8% in this scenario by 2020.[47]

If advanced biofuel deployment accelerates, process stability, reliability and availability could be proven, and production costs could fall to very competitive levels. Advanced ethanol production costs from biochemical and thermochemical routes could decline by 29-45% if capital costs are reduced to the fully deployed, debottlenecked and upscaled plant designs identified in recent studies (Humbird, 2011 and Dutta, 2011). Advanced biodiesel production costs under the same conditions could fall by 40-50% if the capital costs can be reduced to long-run optimised levels (based on Wright, 2010). Fischer-Tropsch synthesis is yet to be deployed commercially using biomass-based feedstocks. However, if deployment can be accelerated and the syngas production from biomass optimised and proven to be reliable, costs in 2020 might be competitive with fossil fuels.

Biogas production using digesters is a relatively simple and mature technology, with little opportunity for cost reductions. However, the upgrading process is an area where relatively small-scale applications have modest deployment numbers. Although the technology is relatively mature and is based on commercial technologies from the chemical industry, the application for biogas upgrading is not yet extensive.[48] A larger market would result in better economies of scale for manufacturers and might also allow increased process integration and off-the-shelf solutions with lower project costs (Nielsen and Oleskowicz-Popiel, 2008). Assuming a 10-20% cost reduction for upgrading units by 2020 would reduce biomethane costs for vehicles by between 1-5% in 2020.

8.2 Outlook to 2020 for PHEV and EV costs

The key cost component for PHEVs and EVs are their battery packs. Cost reductions from improved R&D, economies of scale in manufacturing and learning effects will all help to push down costs in the period to 2020 as deployment accelerates. Learning rates for cells and the remaining pack components and the rate of deployment to 2020 will determine cost reductions. As a result of diverging assumptions on learning rates and the rate of deployment, the cost reduction potential varies widely depending on the source.

Analysis of the existing literature from multiple sources puts the consensus at USD 300-400/kWh for battery pack costs for EVs by 2020 (Contestabile, 2012; IEA, 2013; Element Energy, 2012; NPC, 2012). Meanwhile, PHEV battery packs will remain perhaps two-thirds to twice as expensive (Element Energy, 2012). However, more optimistic projections exist. McKinsey has estimated that EV battery packs could cost as little as USD 200/kWh in 2020 (McKinsey, 2012).

Assuming that battery costs decline to USD 350/kWh for EVs and USD 500/kWh for PHEVs, this will significantly reduce total ownership costs over the life of the vehicle. For instance, the incremental costs of the Ford Focus Electric's 23 kWh battery pack would be reduced by around USD 5 500 in this scenario. At the same time, improvements in battery performance should see the overall life of batteries increase from the current manufacturer's guarantees of around 160 000 km.

The total cost of ownership of EVs in 2020 assuming USD 350/kWh, extended life to 200 000 km, and no change in oil prices in real terms to consumers[49] results in electric vehicles becoming significantly more competitive by 2020 (Figure 8.2). The total annualised cost of ownership, will be reduced by 20-50% depending on the vehicle compared to average battery pack prices in 2012 and a life of 160 000 km. This takes into account the vehicle cost (over a 200 000 km life) and fuel costs. The total annualised cost of ownership in 2020 compared to that for an equivalent ICE vehicle would be 2-13% lower (for the three models where direct equivalents are available) per year. This depends on the region and annual driving distances.

However, given oil market volatility a high oil price scenario could occur if global economic growth recovers more rapidly than anticipated in the next few years. Assuming oil prices increase to between USD 150 to USD 155/bbl by 2020, would increase consumer gasoline prices by around a quarter over 2012 levels by 2020 in the United States. However, smaller percentage increases would be felt in Europe and Japan where gasoline prices are higher due to taxation (U.S. EIA, 2013). This would significantly improve the economics of electric vehicles in 2020. The annualised total cost of ownership for the three EVs – for which there is a direct equivalent – is estimated to be 15-22% lower than their conventional ICE powered equivalent in this high oil price scenario.

47 No changes in the yields of biofuels per tonne of feedstock are assumed in this analysis, although higher feedstock prices might make some small incremental improvements economic.

48 In 2012 just 221 biogas upgrading plants were operating worldwide (Bauer, 2013).

49 The U.S. EIA's latest *Annual Energy Outlook* projects that crude oil prices will be little changed from 2011/2012 prices by 2020 under its Reference Scenario (U.S. EIA, 2013).

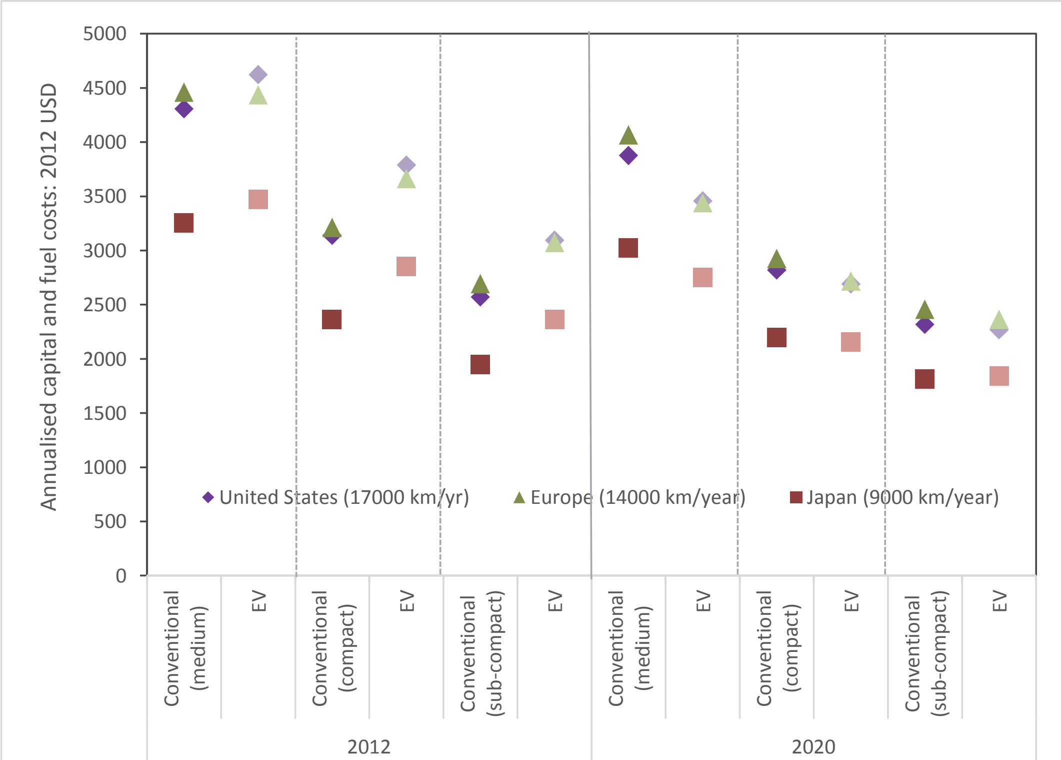


Figure 8.2: Annualised total costs of ownership for EVs in 2012 and 2020

Note: *Analysis is based on Figure 7.7 for 2012. The average cost of capital is assumed to be 10%, and residual value for the vehicle 30% of the MSRP after 200 000 km. Battery pack costs are assumed to decline to USD 350/kWh by 2020. Values for different regions are based on varying annual vehicle use and fuel prices. The results are indicative of annualised running costs. Insurance and maintenance costs are not considered.*

Sources: Table 7.2 for vehicle costs and fuel consumption, Contestabile, 2012; U.S. EIA, 2013; IEA, 2013; Element Energy, 2012a; NPC, 2012; World Bank, 2013; Eurostat, 2013; and IEEJ, 2013.

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