FUTURE FUEL FOR ROAD FREIGHT

TECHNO-ECONOMIC & ENVIRONMENTAL PERFORMANCE COMPARISON OF GHG-NEUTRAL FUELS & DRIVETRAINS FOR HEAVY-DUTY TRUCKS

AN EXPERTISE FOR FONDATION TUCK
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BY

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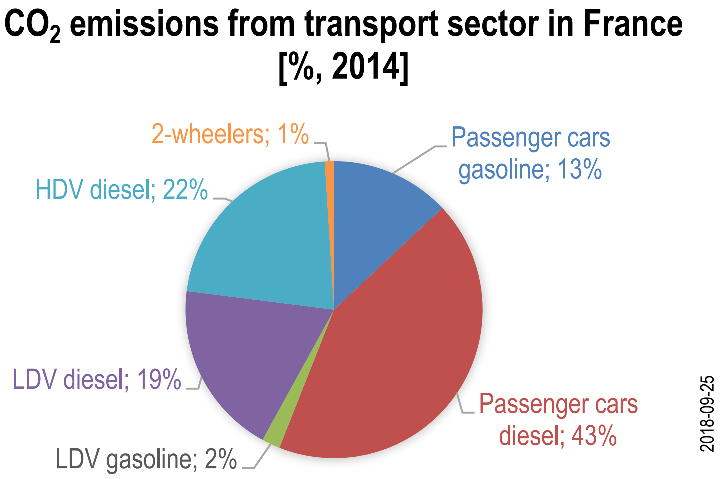
Background & approach

Heavy-duty trucks are responsible for 22 % of greenhouse gas emissions from road transport in France and tractors are the vehicles that transport the most goods (95 % in terms of ton-km). Following the passenger car CO_2 regulation, the EU is about to introduce CO_2 emission performance standards for new heavy-duty vehicles in the order of -15 % in 2025 and -30 % in 2030 (compared to 2019).



The study compares Diesel, CNG/LNG, hydrogen fuel cell (FCEV), and catenary (CEV) powered heavy-duty trucks with regards to their environmental and techno-economic performance for France, including renewable fuel import as an option.

Key results

All alternative powertrains can provide quasi zero greenhouse gas **emissions** based on renewable and low-carbon electricity. Only fuel cell and catenary trucks offer both zero greenhouse gas emissions and zero local air pollutant emissions.

Costs of alternative truck powertrains are converging, series production provided. Costs of new fossil, nuclear and renewable power also are converging. The costs of imported synthetic fuels (synthetic methane via power-to-methane, synthetic diesel via power-to-liquid) are about 20 % lower than those from domestic production.

Based on French stock of long-haul trucks **cumulative investments** have been calculated assuming a ceteris paribus introduction of new fuels/powertrains, incl. primary energy and distribution infrastructure. Fuel cell electric trucks and infrastructure have low cumulative investment among the renewable options. The cumulative investments seem, however, manageable for all options investigated in this study.

Pros & cons

Fuel cell and catenary electric trucks can provide zero greenhouse gas and zero pollutant **emissions** as well as reduced noise signatures at low speeds and during acceleration.

Diesel via power-to-liquid and CNG/LNG via power-to-methane require roughly 2-4 times the **primary energy demand** compared to electric powertrains (FCEV, CEV), translating into a significantly higher number of renewable power plants and area required to cater the e-diesel and e-methane fuel demand.

Hydrogen fuel cell powertrains for trucks share the technology basis and **infrastructure** with other hydrogen uses, e.g. buses and passenger vehicles. The catenary system is exclusive to the relatively small number of long-distance trucks, and possibly buses. CEV competes with rail freight, and possibly public rail transport in case of catenary buses.

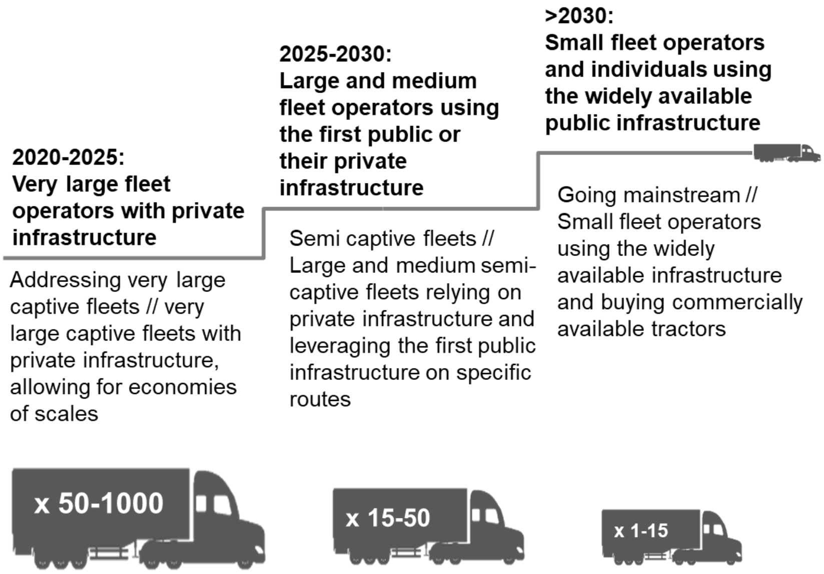
Conclusions & recommendations

Catenary electric trucks can be ideal in case of frequent point-to-point relations. They should be investigated as an option for dedicated ring-fenced projects. **Fuel cell electric trucks** clearly stand out for their combination of zero emission capability and universal use. Hydrogen infrastructure is thus recommended for comprehensive roll-out. Achieving economies of scale across the value chain should be pursued as the number one priority in order to exploit cost reduction potentials as rapidly as possible. On the **fleet operator side**, the priority focus should be put where favourable conditions are given, such as

- Captive fleets because a lower infrastructure investment is required;
- Fleets transporting high-value added goods (>35,000 €/t) for which transport represents a minor element in the cost structure;
- Fleets exposed to societal pressure as an additional driver of change.

On the **infrastructure side**, the priority for investors and operators is to

- Secure long-term supply contracts with at least one large fleet operator, to increase certainty on future revenues and limit risk exposure;
- Reduce fuel costs via economies of scales in order to help fleet operators reach cost parity with diesel;
- Leverage additional revenue streams (grid services, etc.) to strengthen the infrastructure business case.



On the **policy side**, to achieve rapid scale-up, a stable and supportive policy framework would be needed to encourage the appropriate level of private investments. The initial trigger will have to come from **market pull regulation** measures (binding measures such as included in the RED 2, the Eurovignette directive, zero emission zones, the fuel efficiency standards for HDVs directive, etc.), which will spark demand for vehicles, thus justifying investments in upstream infrastructure. However, in the initial deployment phase as FCEVs and CEVs tractors remain more expensive than conventional technologies, **market push instruments** (subsidies, access to cheaper financing, tax exemptions, etc.) will be needed to reduce the cost difference and incentivise fleet operators to make the switch.

Simultaneously, as final demand builds up, investments in infrastructure will need to be de-risked. As a matter of fact, investors in infrastructure are exposed to significant risks on incomes linked to uncertainties and lack of visibility regarding vehicle reliability and ramp up. A number of **market levers** can be activated. First and foremost, public money could be used to support the creation of insurance mechanisms, usually referred to as “take-or-pay contracts”, providing infrastructure investor with a guaranteed level of revenue streams. Public funds could also be used for (co-)financing a minimum coverage of alternative fuel infrastructure. Ideally, this should not be put in place at the individual project level but rather on a larger scale, possibly at the national or even European level, e.g. in the context of the EU Alternative Fuel Infrastructure Directive, by bundling together large deployment initiatives thus mutualizing risks.

Furthermore, capturing additional layers of **revenue streams** can also contribute to mitigate financial risks for investors. Facilitating access to the ancillary services market for electrolyser could possibly play a major role in this regard. In addition, allowing gas grid injection and creating a suitable injection tariff (typically 90 €/MWh) could also help to de-risk investments during the ramp up phase.

On the way to achieving the Paris climate goal, subsidies will cease to exist and will be replaced by **regulations** such as CO_2 taxes, to bridge the potential remaining difference in total cost of ownership with conventional technologies.

1 Background, Approach, and Methodology

Heavy-duty vehicles, notably those operating on long-haul, are the ‘elephant in the room’ when discussing climate change mitigation strategies for road freight transport.

The majority of commercial vehicles (by stock count) are small to medium in size (3.5-20 t gross vehicle weight and below). A major concern in this vehicle category is air pollutant emissions in urban areas. Confidence is rising that this may be technically addressed using partially or fully-electrified drivetrains, such as battery-electric (BEV), fuel cell-electric (FCEV) or combinations thereof (PHEV, REEV).

The bulk of final energy used for road freight transport is consumed by a relatively small number of heavy-duty trucks belonging to the ~40 t gross vehicle weight class.

On 20 December 2018, the EU Council agreed its position on a proposal to reduce CO_2 emissions for heavy-duty vehicles (trucks and buses) by 15% from 2025 and by at least 30% by 2030 (based on 2019 values) [Consilium 2018]. This agreement provides the presidency with a mandate to start negotiations with the European Parliament (which on 14 Nov. 2018 had proposed targets of a 20% reduction by 2025, and a 35% reduction by 2030). The aim will be to save 54 million tons of CO_2 in the period 2020 to 2030.

There are several types of strategies and measures to address greenhouse gas mitigation in transport, e.g. the ‘ASIF’ approach includes Avoid (sufficiency), Shift (modal split), Improve (efficiency), and Fuel (renewable energy) [Ifeu/Infras/LBST 2016, p 61ff]. This study is analyzing the potentials from fuel and powertrain options. Over the last years, a number of fuel/drivetrain combinations have been proposed to diversify the Diesel dominance in heavy-duty long-haul applications and to introduce renewable fuels in this high-performing and economically challenging application.

The **objective** of this study is to sort out the cards by presenting the current state of technologies, discussing pros and cons of each technology, and proposing technology options and policy levers for advancing greenhouse gas-neutral road-freight transport. The fuel/drivetrain combinations depicted in Table 1 are thus investigated for long-haul heavy-duty trucks with ~40 t gross weight.

Table 1: Fuel/drivetrain combinations investigated in this study

Primary energy	Fuel	Drivetrain
Reference		
Crude oil	Diesel	ICE
Natural gas	CNG / LNG	ICE
	Hydrogen	FCEV*
French grid mix	Electricity	BEV* with pantograph (catenary)
Low carbon		
Nuclear power	Diesel via power-to-liquid	ICE
Renewable		
100 % renewable electricity	Diesel via power-to-liquid	ICE
	Methane via power-to-methane	ICE
	Hydrogen via power-to-hydrogen	FCEV*
	Electricity	BEV* with pantograph (catenary)

* zero (local) emission vehicle

The time horizon for comparative analyses of fuel/drivetrains in this study is short-term (2020+) and long-term (2030+), the latter against the backdrop of what needs to be done to achieve the Paris Agreement (2050+).

For this, chapter 2 gives in overview over the current state of truck us in France and regulatory in France and the EU. In chapter 3, 4, and 5 the truck fuel and powertrains are assessed in two steps (well-to-tank, tank-to-wheel), and conclusions are drawn from the well-to-tank results, respectively. Finally, in chapter 6, challenges and levers for the introduction of most promising fuel/powertrain combinations are discussed.

The following **methodological definitions** have been applied for this study:

- Greenhouse gases

Greenhouse gases considered in this study are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)[1]. The global warming potential of the various greenhouse gases is expressed in CO_2 equivalents. Table 2 shows the global warming potential for a period of 100 years according to the Fourth and Fifth Assessment Reports (AR4 and AR5 respectively) of the Intergovernmental Panel on Climate Change (IPCC).

[1] Other greenhouse gases are CFCs, HFCs, and SF6, which are, however, not relevant in this context.

Table 2: Global warming potential (GWP) of various greenhouse gases [IPCC 2007], [IPCC 2013]

Greenhouse gases	IPCC Assessment Report 4 (g CO_2 equivalent/g)	IPCC Assessment Report 5 (g CO_2 equivalent/g)
CO_2	1	1
CH_4	25	30*
N_2O	298	265*

* Table 8.A.1 of the Fifth IPCC Assessment Report

Leading research institutions (e.g. Argonne National Laboratory for its tool 'GREET 2014') have already started to use the values of the latest (fifth) IPCC report, i.e. a GWP of 30 g/g for CH_4 and 265 g/g for N_2O [2] [IPCC 2013]. However, in this study the AR4 values have been used because they are also used in the recast of the Renewable Energy Directive.

The energy requirements and greenhouse gas emissions resulting from the construction and decommissioning of manufacturing plants are not considered here. Furthermore, energy requirements and emissions resulting from the manufacturing and decommissioning of installations and vehicles are not considered either analogous to JRC/EUCAR/CONCAWE methodology for well-to-wheel studies.

- Efficiency method

For the calculation of the energy requirements the so-called 'efficiency method' has been used similar to the procedure adopted by international organisations (IEA, EUROSTAT, ECE). In this method the efficiency of electricity generation from nuclear power is based on the heat released by nuclear fission which leads to an efficiency of about 33%. In the case of electricity generation from hydropower and other renewable energy sources that cannot be measured in terms of a calorific value (wind, solar energy) the energy input is assumed to be equivalent to the electricity generated which leads to an efficiency of 100%. The efficiency of geothermal electricity generation is set to 10%.

- Cost calculation

All costs have been calculated on a full cost basis and without taxes in order to gain a conservative, robust and level-playing field for cost comparison. An interest rate of 4% has been assumed for the calculation of the costs for capital. The depreciation period is assumed to be equal to the lifetime of the plant.

Specific investments have been calculated including technology-specific learning curves. Where needed, cost data has been adapted using the Chemical Engineering Plant Cost Index (CEPCI), see Figure 1.

[2] Without climate-carbon feedback (cc fb).

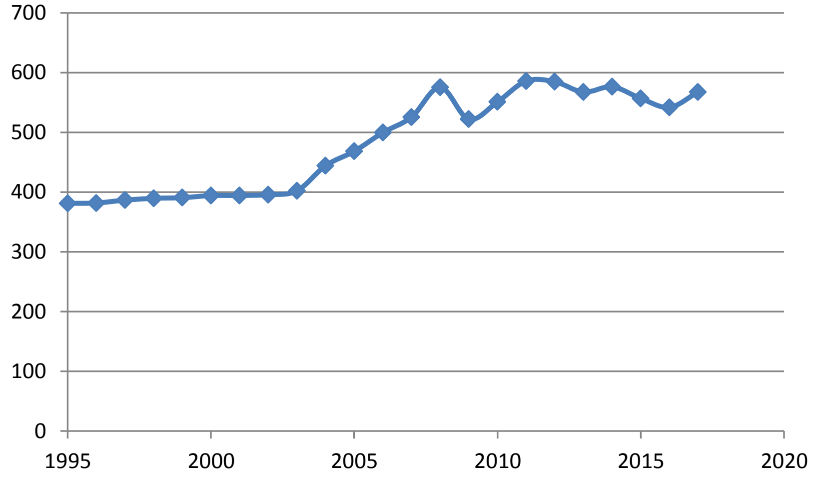


Figure 1: Development of the Chemical Engineering Plant Cost Index (Image: LBST; Data: [Chemical Engineering 2016], [NTNU 2012])

2 SETTING THE SCENE FOR FRANCE AND THE EU

Long-haul tractors are the heavy-duty vehicles that contribute the most to GHG emissions in France. At the same time, tractors represent a much smaller fleet compared to passenger vehicles and light duty vehicles. Moreover, the majority of the goods in France are transported on long-haul distances.

In that respect, long-haul tractors are therefore the category of road vehicles with the least vehicles where a clean drive train will impact the most the overall GHG emissions.

In this section, the following aspects will be investigated:

1) The overall number of registered heavy duty vehicles and resulting GHG emissions;
1) The breakdown of ton-km per heavy-duty vehicles for transport of goods and the number of registered HDV per weight class today and in 2030
2) The estimate of GHG emissions for the entire fleet of long-haul tractor in France;
3) The typical breakdown of annual costs for a long-haul tractor;
4) The EU and French regulation framework applying to tractors, in particular in regards to emissions reductions.

2.1 General GHG context for road transport in France and the overall number of registered vehicles

Heavy duty vehicles contribute to 22% of all road transport emissions, although having a smaller fleet relative to light duty vehicles (1 to 10 factor) and passenger vehicles (1 to 60 factor).

First, when looking at different terrestrial transport of goods modes, road transport is the most used by a wide margin. Both boat (~2%) and train (<10%) remain a marginal transportation mode compared to road transport from a ton-km point of view [CG DEV 2018]. Therefore, GHG emissions will be comparatively low for both trains and boats.

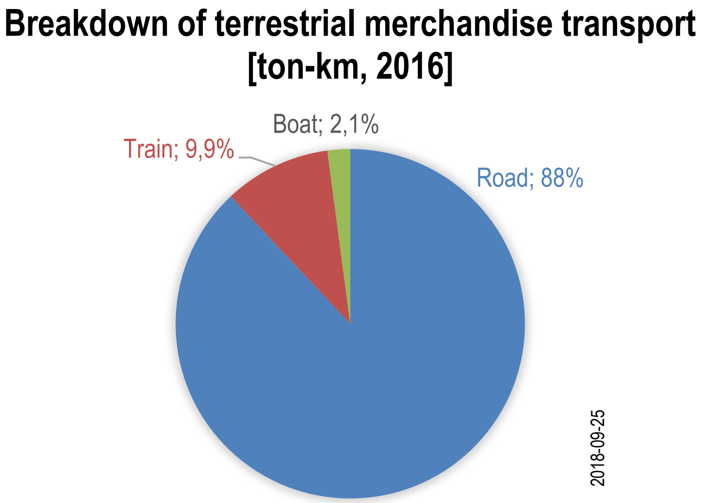


Figure 2: Breakdown of terrestrial merchandise transport by ton-km

Heavy duty vehicles (HDV) contribute to 22% of all road transport (both passenger and goods) GHG emissions, representing 26,4 $MtCO_2$. However, there are only half a million HDV on the road, compared to 6.2 million light duty vehicles (LDV), which contribute to 21% of GHG emissions; and compared to 32 million passenger cars, which contribute to 56% of GHG emissions [CITEPA 2016] [RSVERO 2018].

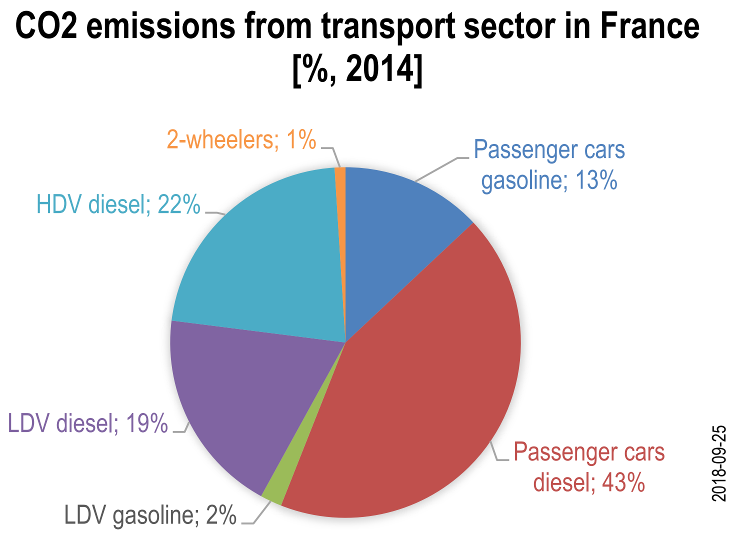


Figure 3: CO_2 emissions from transport sector in France in 2014

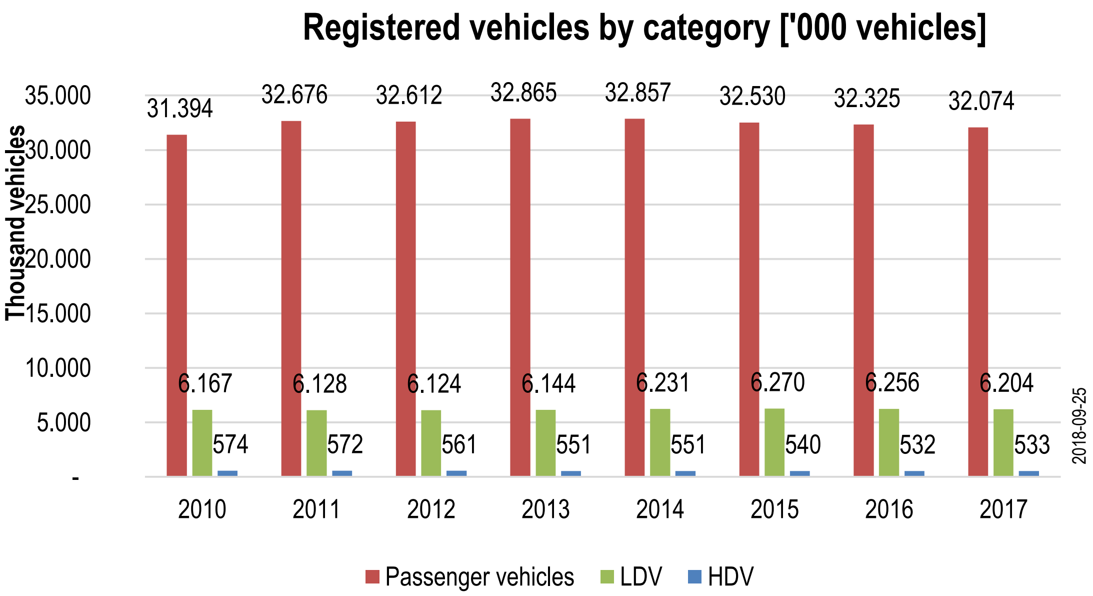


Figure 4: Registered vehicles by category

2.2 Breakdown of ton-km per heavy-duty vehicles for transport of goods and the number of registered HDV per weight class

Tractors can transport larger payloads and are convenient for fleet operators thanks to their flexible tractor-semitrailer configurations. Today, tractors transport the majority of goods in France.

Goods can be transported in large quantities by two different types of trucks on the road:

- Rigid trucks
- Tractors

Regulation defines the gross vehicle weight (GVW) of a truck. While rigid trucks can be classified per different weight class (and thus different available payloads), tractors can accept all kinds of different payloads by selecting appropriate semi-trailers in function of their needs. Therefore, a fleet operator usually owns more semi-trailers than tractors to optimize his operations.

Moreover, the highest allowed GVW on the road in France is defined for tractors, at 40 tons, which allows tractors to transport the most payload in one trip, as shown in the figure below.

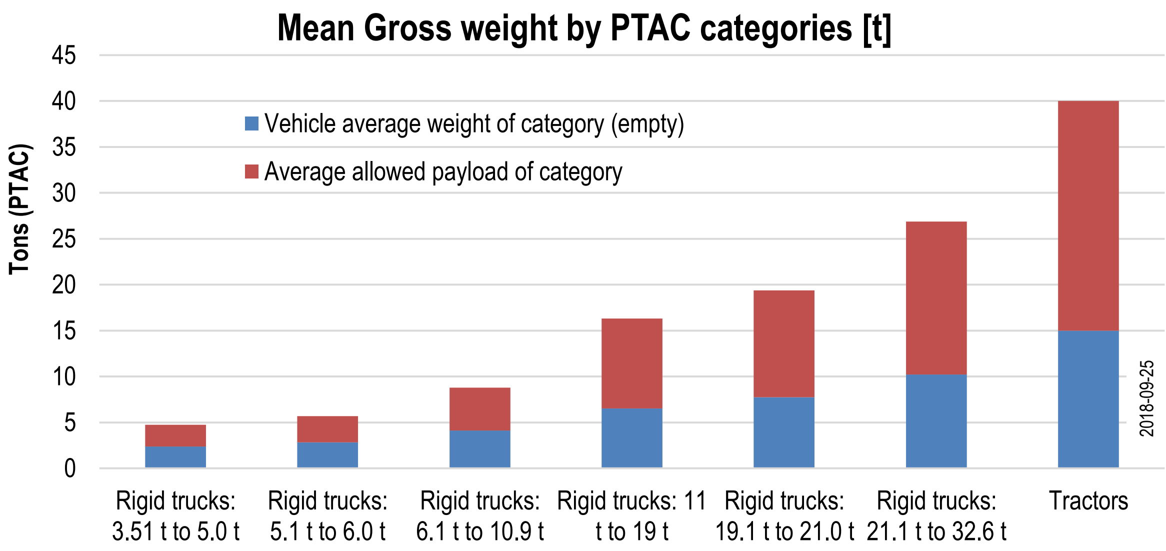


Figure 5: **Mean Gross weight by PTAC categories**

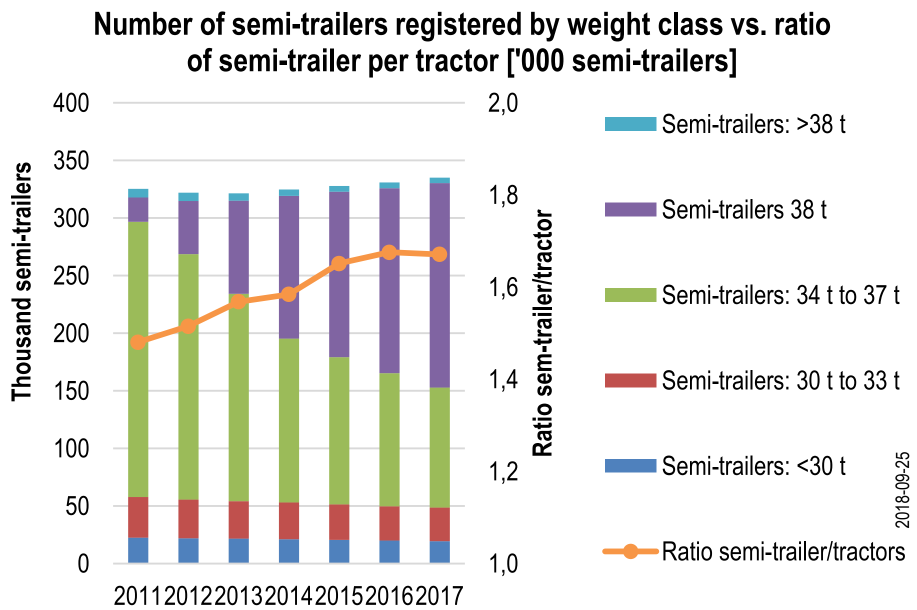


Figure 6: **Number of semi-trailers registered by weight class vs. ratio of semi-trailer per tractor [RSVERO 2018]**

Over long distances (>100km), the majority of the ton-km, a proxy for fuel consumption and emissions, in France are transported by tractors.

Thanks to its flexible configuration and its higher payload, tractors transport more goods in France than rigid trucks regardless of the daily mileage [TRM 2017].

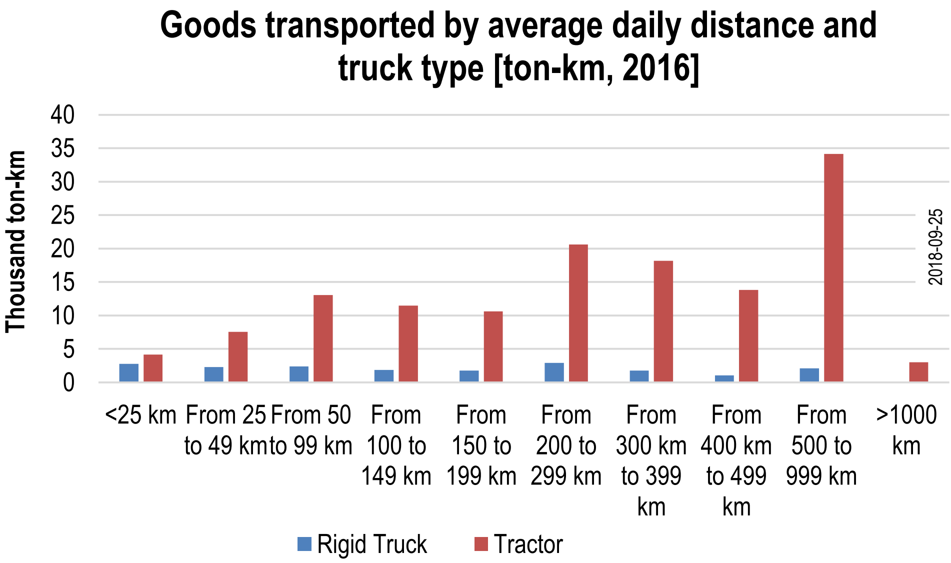


Figure 7: Goods transported by average daily distance and truck type

Looking at the shares of ton-km transported, tractors dominate the market with more than 95% of market share, even though there are 200,000 tractors compared to 330,000 rigid trucks. Within the tractor segment, inter-urban volumes (in terms of ton-km) are dominant.

There is an approximately 60-40 split in terms of registered vehicles between rigid trucks and tractors. Both categories have seen a small decline in the number of vehicles registered in France in the last years. However, at a more granular level, the number of registrations of rigid trucks in the 19.1t to 21t and >26.1t segments have increased contrary to other categories. In 2017, the 11t to 19t category (50%) was the most populated for rigid trucks, followed by the 21t to 26t segment (20%). [TRM 2017]

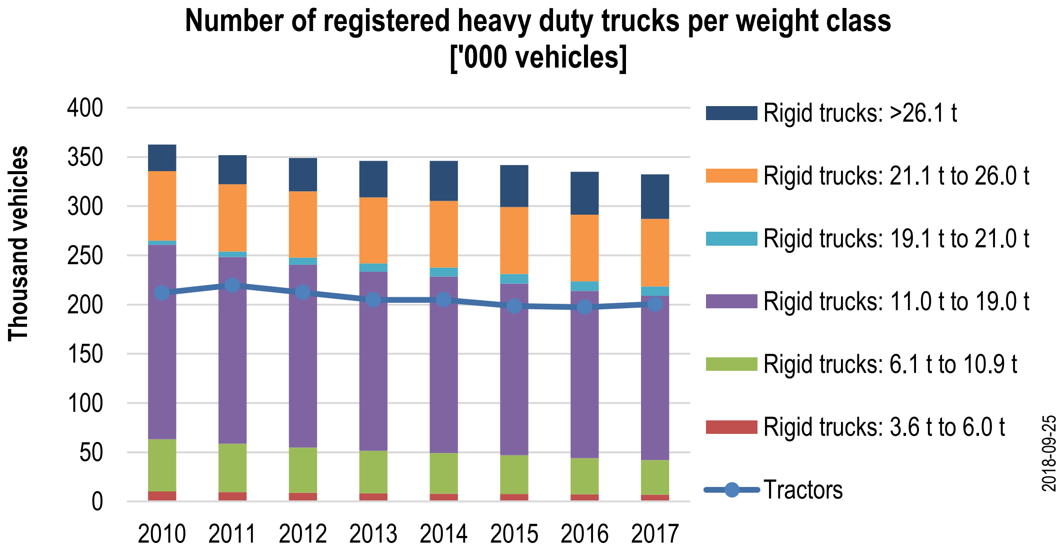


Figure 8: Number of registered heavy duty trucks per weight class

Even though there are less tractors than rigid trucks, they transport more than 95% of the goods on the road in terms of ton-kms [TRM 2017], with the majority of tractors transporting the goods on long-haul (or inter-urban) distances.

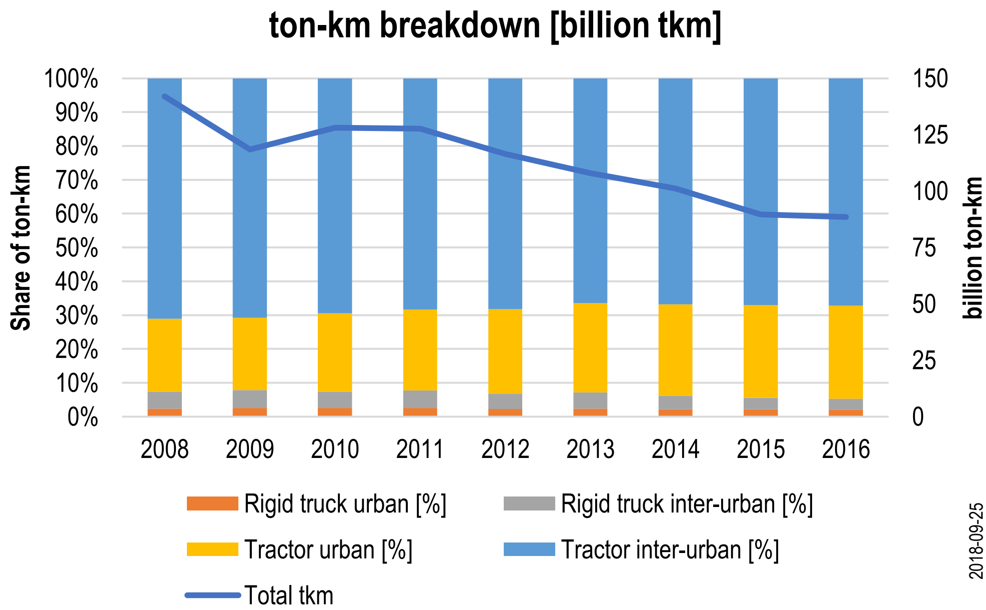


Figure 9: Ton-km breakdown by route type and vehicle type

Looking ahead, tractors are expected to remain the preferred option for transport of goods in France. In 2030, the number of registered tractors is expected to increase slightly from today, which would increase GHG emissions as a result if no action is taken.

Although the market for tractors and rigid trucks is expected to stagnate in the short term, one can still expect a moderate rise in the number of km driven. It should be noted that growth is expected to be stronger for tractors (CAGR: 1%) than for rigid trucks (CAGR: 0.2%). [RB 2018].

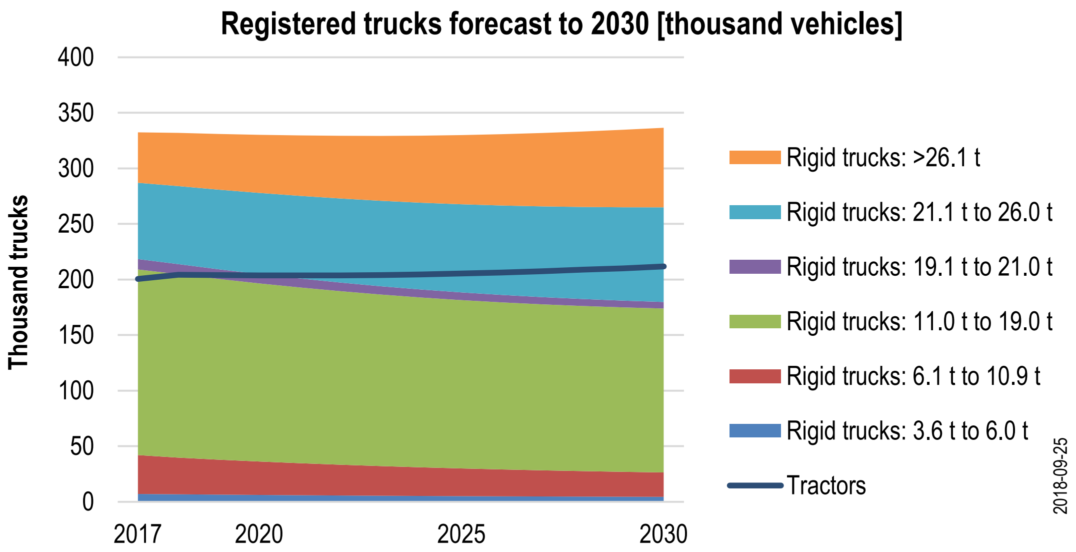


Figure 10: Registered trucks forecast to 2030

2.3 Estimation of the GHG emissions of the long-haul tractor French fleet

Yearly CO_2 emissions are correlated with the annual mileage and the average payload. Over a year, an average tractor will drive 114,100km and emit 131 tons of CO_2 in the air, with the bulk of the emissions taking place while the truck is loaded.

To model the GHG emissions of a tractor, one has to take into account several parameters:

- Number of annual km driven
- Number of km driven with a non-zero payload
- Percentage of maximal allowed payload used when loaded
- GHG emissions per km & average payload from [TNO 2018].

The GHG calculations are based on an estimation of GHG emissions in function of average payload [TNO 2018].

$$GHG = 35.3 * (average\ payload\ [ton]) + 573\ [\frac{gCO2}{km}]$$

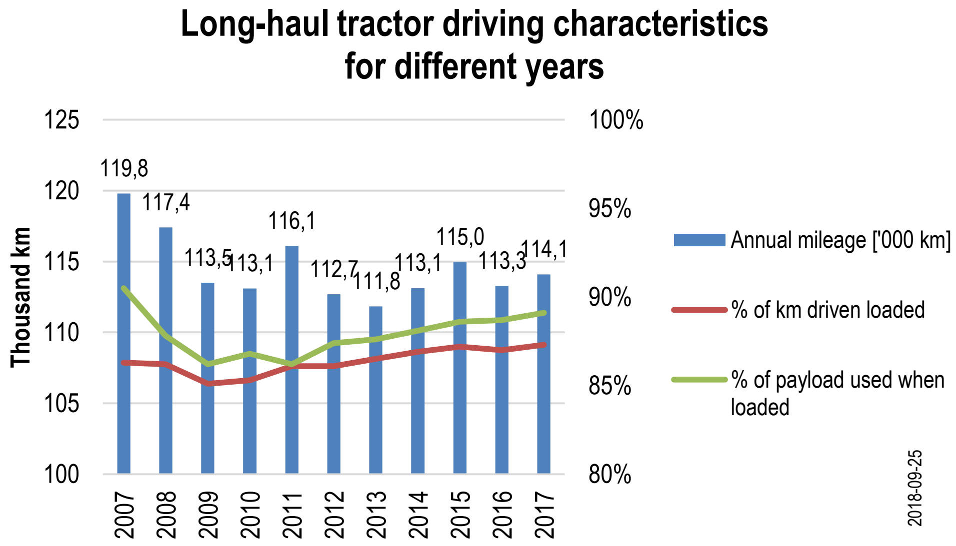


Figure 11: Long-haul tractor driving characteristics for different years [CNR 4/2018]

Considering all the above-mentioned parameters, we calculate that in 2017, an average tractor emits 131 tons of CO_2 annually.

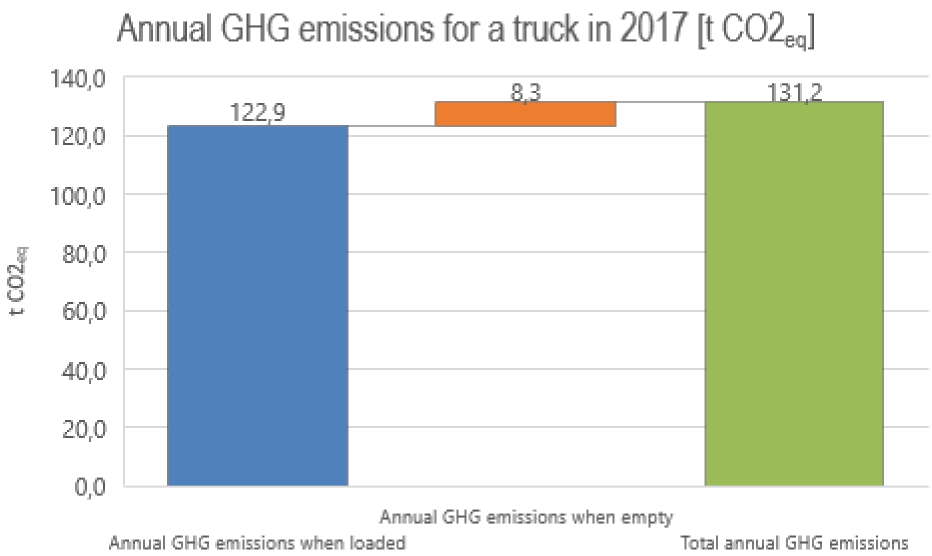


Figure 12: Annual GHG emissions for a truck in 2017

In recent years, the EURO pollutants regulations have acted as a strong push in favour of the introduction of less polluting trucks. However, the new drivetrain technologies have not affected fuel efficiency.

New Euro truck models are introduced on the market as a results of ever-tighter EU emissions standards for road transport. In 2017, more than half of all tractors on

French roads were in line with EURO 6 standards and less than 7% were still EURO 4 or below. [CNR 4/2018]

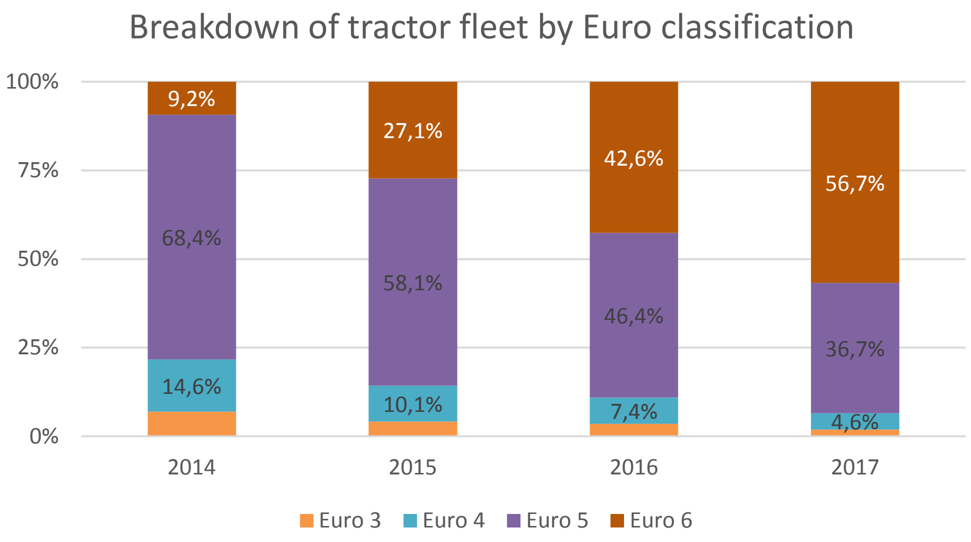


Figure 13: Breakdown of tractor fleet by Euro classification

Today, according to published fuel efficiency by manufacturers, a tractor consumes on average just under 35 L/100km. Fuel consumptions have however not enhanced in the last 7 years, which means that the CO_2 emission intensity of a tractor has not changed either.

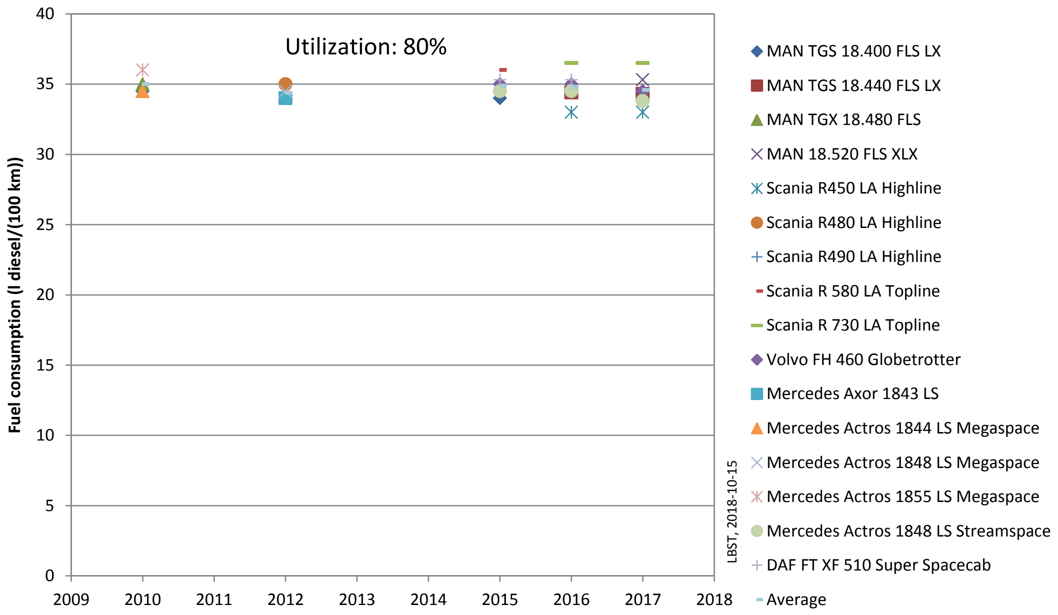


Figure 14: Aggregated fuel consumption of truck manufacturers (image: LBST, data: lastauto omnibus katalog from 2010 to 2017)

In 2016 the GHG emissions of the entire French fleet of long-haul tractors represented an estimated 18.5 MtCO2.

18.5 MtCO2 were emitted by long-haul tractors in 2016, which was estimated based on the hypothesis that the distribution between long-haul tractors and urban tractors is the same as the distribution of ton-km in Figure 15. For instance for 2016, 71% of the 197,397 tractors were used to transport goods on long-haul distances. The number of long-haul tractors is then multiplied by GHG emissions from a long-haul tractor calculated previously, to obtain the total GHG emissions of the French fleet.

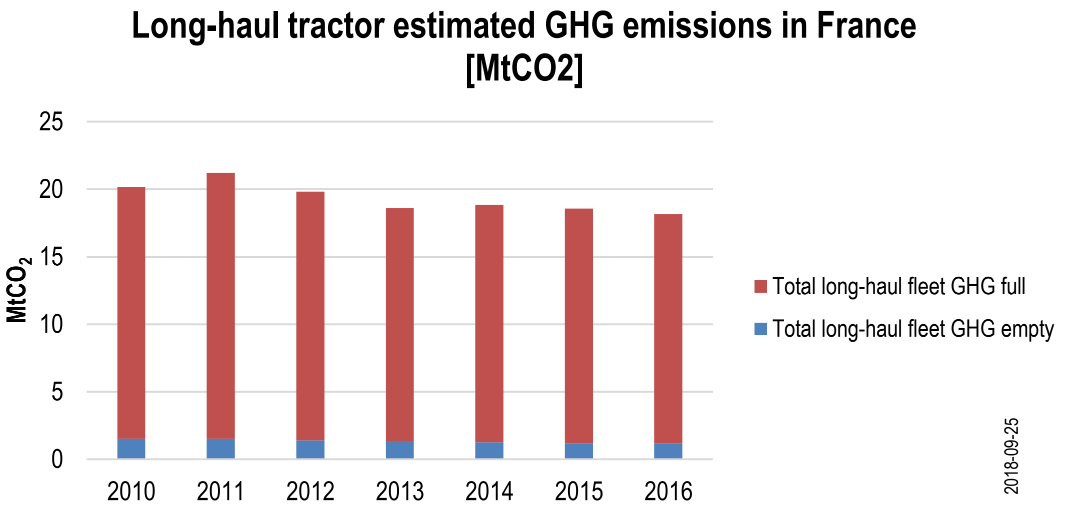


Figure 15: Long-haul tractor estimated GHG emissions in France

2.4 Breakdown of annual costs for a long-haul tractor

The business case of transport companies is highly dependent on fuel cost, which is the second largest cost component after the driver salary costs.

In 2017, the total annual costs associated with owning and operating a long-haul tractor amount to 143,000 €, representing a TCO of 1.25 €/km. [CNR 4/2018]

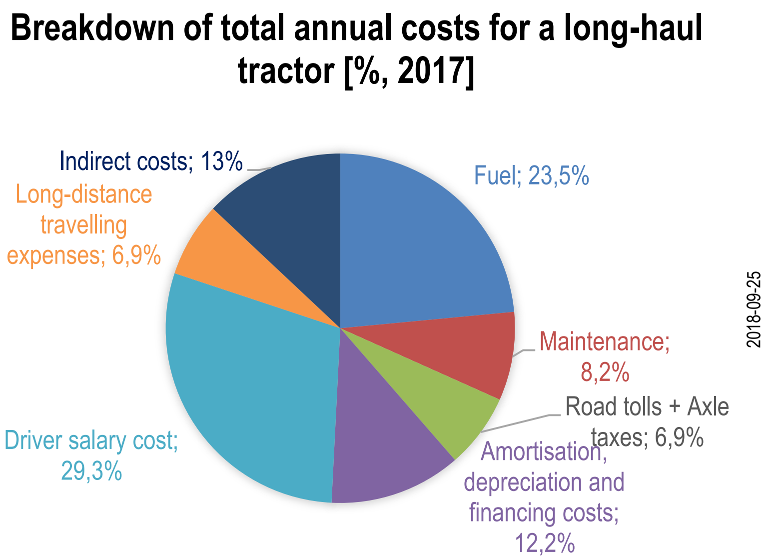


Figure 16: Breakdown of total annual costs for a long-haul tractor

Looking at the sensitivity analysis below, we can see that an increase of 20% in fuel costs results in a total cost increase of 4.7% for the owner, which directly impacts its margin in similar proportions. It should also be noted that, the owner's economics will be less impacted by an increase of the tractor's purchase price, as these components represents a smaller share of the total.

Table 3: Sensitivity analysis on TCO

Impact on total costs of a ±20% change of each independent category	
Fuel	±4.7%
Maintenance	±1.6%
Road tolls + Axle taxes	±1.4%
Amortization, depreciation and financing costs	±2.4%
Driver salary costs	±5.9%
Long-distance travelling expenses	±1.4%
Indirect costs	±2.6%

2.5 EU and French environmental & tractor regulation framework

Currently and in the short-term, no regulatory framework both at the EU level or at the national level is favouring the adoption of zero-emission long-haul tractors. In the mid to long-term, the fuel efficiency standard for HDVs, the RED 2 and the Eurovignette will drive the adoption of zero-emission drivetrains in this category of vehicles.

EU environmental regulations, such as the Euro emission standards, have had a big impact in the past on how the intensity of truck pollution has drastically been reduced and how the market is shaped today. Euro emissions standards have been used to define upper limits for trucks and tractors for the emissions of pollutants such as NOx and CO on stationary (meaning with the engine turning at a constant speed) and transient cycles (to see the impact of dynamics on the emissions).

The first European emissions standards for heavy-duty vehicles were introduced in 1988, with the first “Euro” standard being implemented in 1992. The specificity for HDV is that emissions are tested on the engine itself and not on the entire vehicle. The restrictions are typically expressed in grams of pollutant per kWh. Over the years, different testing cycles have been applied. Today and for the Euro VI standard, the world harmonized stationary cycle (WHSC) and the World harmonized transient cycle (WHTC) tests are applied.

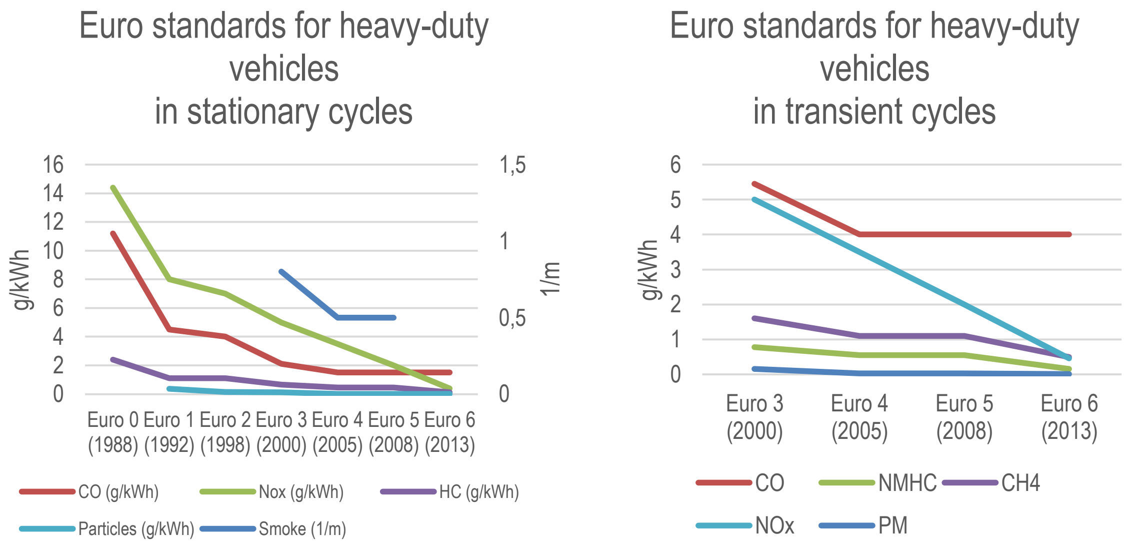


Figure 17: Euro emissions standards for HDVs in stationary and transient cycles [TP 2018]

To assess the effective CO2 emissions of trucks and to set benchmark values, the EU and the French government are setting up legislative frameworks to monitor CO2 emissions of trucks.

To date, CO2 emissions of heavy-duty trucks have not been monitored in a systematic way in the EU. As of 1st of January 2019, all lorry manufacturers will have to report annually to the European Commission (EC) the CO2 emissions and fuel consumption of each vehicle they commercialize onto the European market. Manufacturers will be required to use the Vehicle Energy Calculation Tool (VETCO), which is a simulation software designed to calculate the performance of an HDV.

In parallel, the French government has implemented in October 2013 the article L. 1431-3, which compels all companies transporting goods or persons to disclose their GHG emissions. The aim was to promote low carbon transport and to raise awareness about the GHG content associated to a transport of person or goods. The calculation method is based on the European CEN standard EN 16258, which specifically defines the methodology for calculation and reporting of energy consumption and GHG emissions of transport services (freight and passengers).

By 2030, in the context of the discussion around the first CO2 emissions standards on HDVs, newly manufactured trucks will have to emit 30% less CO2 emissions compared to 2019. In a first step, the category of large lorries (> 16 tons for the 4x2 and all the 6x2 trucks) will be the first to be regulated. Low- or zero-emission trucks will also have to represent 20% of market shares by 2030.

To achieve the target of 30% CO2 reduction target by 2030 for non-ETS (Emissions Trading System) sectors (as transport belongs to the non-ETS category) compared with 2005, the EU parliament is currently in discussion for the first ever CO2 standards on HDVs. The objective is to achieve, compared to 2019, a 20% reduction in CO_2 emissions by 2025, and a 35% reduction by 2030 [EC 2018]. In the current status of the directive, it is specified how and from which dates forward the CO2 emissions standards for HDV are to be applied, with large lorries being the first category to be regulated and with other categories following through. In this regard, the VECTO simulation tool is used as a tool to determine the level of baseline emissions in 2019.

This would be the first CO2 standard regulating HDVs in the EU, whereas similar standards have already been implemented in the US, Japan, China, Canada and India.

Manufacturers will also have to ensure that zero- and low-emission vehicles (which emit at least 50% fewer emissions) represent a 20% market share of the total new sales by 2030 (and already 5% by 2025). [EC 2018]

Effective and costless fuel efficiency (Tank-to-Wheel) improvements could already be achieved today. They could be applied either to the truck itself or to other influencing factors, such as increasing the GVW limits or allowing truck platooning.

Cost-effective measures to reduce fuel consumption are already available today. They can be classified as [TNO 2018]:

- Aerodynamics (such as roof spoilers, mud flaps, longer and rounded vehicle fronts, side and underbody panel at truck chassis, etc.)
- Transmission (such as loss reduction measures with enhanced lubricants and new designs, and a switch from manual transmission to AMT)
- Weight (reducing the weight of tractors)
- Engine (such as improved turbo charging and Exhaust Gas Recirculation (EGR), friction reduction, improved lubricants, waste heat recovery, downspeeding, engine downsizing)

- Auxiliaries (such as electric hydraulic power steering, LED lightning, air compressors, cooling fans)
- Tyres (such as low rolling resistance tyres, tyre pressure monitoring systems, automated tyre inflation systems)
- Hybridisation (such as 48V system with starter/ generator, and electric hybridisation)

Other indirect methods, which do not apply directly on the manufacturing of a tractor, can also help reduce the fuel consumption, such as

- Truck platooning, which has the potential to reduce CO2 emissions by 10% [ACEA 2018], which involves an investment in automation software, and modifying road regulation.
- An increase of the length and GVW limits for trucks (could reduce CO2 emissions by 14%)
- Aerodynamic and/or low rolling resistance trailers

With respect to the allowed GVW, the EU Directive 2015/719 sets the length and the weight limits of tractor-trailer combinations. It sets the norm for 44-ton circulation for HDVs and sets the length limit of 16.5m for tractor-trailers and 18.75m for a tractor-trailer pulling a drawbar trailer.

Currently, vehicles with aerodynamic devices are allowed to exceed the 16.5m limit length by 50 cm, bringing the total allowed length to 17m.

Enhancing the Well-to-Tank (WtT) CO2 emissions is also a critical aspect of the fight against climate change. The revised Renewable Energy Directive (RED 2), which targets to have 14% of renewable fuel in road and rail transport energy consumption by 2030, will push the creation of new business cases around transport.

To achieve the 40% EU objective of CO2 emissions reduction, tank-to-wheel improvements will not suffice. In this regard, Well-to-Tank CO2 emissions will thus be tackled with the revision of the RED (and to some extent Well-to-Wheel depending on methodologies to be developed via delegated acts)

The upcoming RED revision, still at the drafting phase as of writing this report, states that **each member state (MS) is** to set an obligation **<u>on fuel suppliers</u>** to ensure a share at least **14%** of renewables in final consumption of the transport sector in 2030 (to be revised upwards in 2023).

The fuels that are likely to be considered eligible to count in the target of 14% of renewable fuels in the final consumption of energy of the transport sector are the following:

- Biofuels from food and feed crops (with certain limits, and CO2 reduction targets)
- Biofuels and advanced biofuels from the feedstock as listed in the Annex IX of the draft

- Renewable liquid and gaseous transport fuels on non-biological origin (with a CO2 reduction target to be determined as a delegated act), such as e-fuels (PtX: E-H2, E-diesel, E-methanol, E-methane) from renewable sources, which can be considered as zero-carbon fuels if the source of electricity is zero carbon.
- Recycled carbon fuels (if decided by MS) (such as gasification of waste)
- Electricity

Moreover, the intermediary products used in the production of fossil fuels (diesel, gasoline, etc.) can also be eligible to count towards the transport objective, should they be made from renewable sources. This will likely push refineries to green the hydrogen supply used in their internal processes.

Many things might still evolve in the directive, as well as during the MS implementation as many delegated acts are possible. However, it is important to highlight that the implementation of this directive will act as a major driver for the adoption of new fuels in transport and for the creation of new business cases around renewable fuels, such as those considered in the subsequent sections of this report.

Taxing heavy duty vehicle circulation and GHG emission is an effective measure to reduce pollution and congestion. In Switzerland, this framework has pushed HDV operators to convert their entire fleets to zero-emission alternatives, as the recent purchase of 1000 FC rigid trucks by COOP perfectly exemplifies.

Rigid trucks and tractors highway traffic causes a series of critical consequences, with the pollution, the congestion and the road wear all deteriorating. A series of measures have been undertaken by EU member states to reduce the circulation of HDVs or to limit its effects, such as road taxation. The implementation of theses road taxes differs from MS to MS, some might only tax the highways, others will tax in function of the length of the trip, the EURO truck class, etc. There is thus no consensus yet on how to tax HDV circulation and today the implementation is different in Austria, Germany, Denmark, Luxembourg, the Netherlands, Sweden, Belgium, Slovakia, Poland, the Czech Republic, Portugal and finally the United-Kingdom.

In parallel, the EC is developing the Eurovignette directive, which, as of October 2018, was submitted to plenary. This directive looks at how Member States can regulate the circulation of heavy-duty vehicles using road taxes or toll charges. Two aspects of this directive relate to GHG emissions:

- The toll charges should take into account reference CO_2 emission values and the relevant vehicle categorisation.
- Zero-emission vehicles shall benefit from infrastructure charges reduced by 75% compared to the highest rate.

A recent “success-story” is the Swiss case: originated by a popular initiative called “the Alpes initiative” voted in a referendum, the Swiss government implemented a road tax to reduce traffic and pollution of all HDVs (both Swiss and international) on its roads. The secondary objective was effectively to reduce the cost gap between rail and road, and the tax was thus designed to make rail freight less costly than road. This tax represents approximately a sizeable increase of 10-20% on top of the TCO of HDVs in Switzerland.

In 2011, the Swiss government produced a report synthesising the main outcomes of the road tax:

- Reduction of the circulation of empty trucks on the road
- Enhancement of the productivity of the road sector
- Reduction of the road traffic
- A yearly income of 1.2 b€, a third of which being used for the maintenance of the roads, and the rest for the maintenance of the rail infrastructure

Furthermore, it is noteworthy that this tax does not apply to zero-emission trucks, which has pushed local players to search for alternative solutions. As a matter of fact, food distributors, for which modal shift to rail is not an option in cities for last-mile delivery, have been intensely looking for alternative HDVs powertrains. For instance in 2018, the two major food distributors of Switzerland have announced the order 1000 FC trucks from Hyundai and the creation of a national hydrogen refuelling infrastructure together with the majority of the Swiss fuel station operators.

This success story was only made possible by the adoption of a very high road tax, driving FC trucks at cost parity compared to diesel.

3 FUELS & INFRASTRUCTURES (WELL-TO-TANK)

In this chapter a consistent set of fuel and infrastructure data is developed.

3.1 Scope

The pathways depicted in Table 1 (see above introductory chapter 1) are investigated in this study.

Costs are calculated based on a full cost basis, excluding taxes, duties, and subsidies, to provide an accurate picture of the intrinsic relative competitiveness of the different options under scrutiny.

100 % renewable electricity is assumed to provide the additional renewable electricity production needed to cater new electricity demands from the transport sector. For this, a mix of wind and solar is assumed as their generation costs have dropped massively and their generation potential even within EU-28 is significantly beyond todays' electricity demands [LBST & dena 2017]. For the production of Diesel via power-to-liquids it was decided to also consider nuclear power. Here, too, new nuclear capacities are assumed to cater potentially substantial additional electricity demands from transport.

For the production of power-to-methane ($PtCH_4$) and power-to-liquids (PtL) – i.e. electricity-based synthetic fuels or 'e-fuels' – CO_2 is needed as feedstock. With a view to achieve full carbon-neutrality and because of its abundant availability globally, CO_2 extracted from air is assumed as carbon feedstock for the synthesis processes. This is a conservative assumption to provide the fundamental data. It is thus ensured that short-term opportunities with limited potential[3] and geographic availability give no bias in the comparison. Using e.g. CO_2 from biogas upgrading can be building blocks for project-specific localized business case assessments.

The fuel supply includes the extraction of fossil and nuclear primary energy, the generation of renewable electricity, their processing, and the transport & distribution of the final fuels.

3.2 Pathway description

3.2.1 Diesel from conventional crude oil (reference)

Crude oil is extracted and transported to crude oil refineries in the EU where it is converted to gasoline, jet fuel, diesel, and other oil products. From there the crude oil is transported to a depot via rail, pipeline, and ship. From the depot the diesel is transported to the refueling stations.

[3] Compared to today's level of fuel consumption.

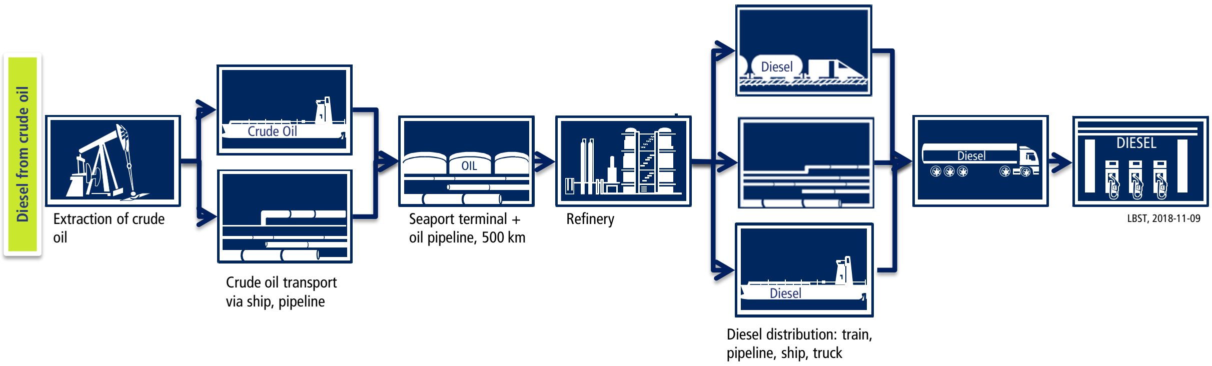


Figure 18: Pathway diagram of Diesel supply from import of conventional crude-oil (fossil comparator)

The energy requirements and greenhouse gas emissions for the supply of crude oil have been derived from [Exergia et al. 2015] where the average crude oil mix delivered to the EU has been assessed. The data have also been used for the recast of the EU Renewable Energy Directive and will also be included in the update of the JEC well-to-wheel study [JEC 2014]. The crude oil input and greenhouse gas emissions of the crude oil refinery and distribution of the final work is based on work for the update of [JEC 2014].

Table 4 shows the emissions of greenhouse gases for the supply of diesel from crude oil.

Table 4: Greenhouse gas emissions from supply of diesel from crude oil

Process step	g CO_2 equivalent/MJ of diesel
Crude oil supply	10.7
Crude oil transport	0.8
Crude oil refining	7.2
Diesel distribution	0.5
Diesel refuelling station	0.4
Well-to-tank total	**19.7**

The combustion of crude oil based diesel in the vehicle (tank-to-wheel) leads to about 73.2 g of CO_2 per MJ of diesel. As a result the supply and use (combustion) of diesel leads to about 92.9 g CO_2 equivalent per MJ of diesel.

Table 5 shows the crude oil prices and the resulting prices for diesel.

Table 5: Crude oil price and resulting diesel price

	Unit	2020	2030	Reference
Crude oil	US$/bbl	60	72	[IEA 2018]
	€/bbl	53	64	
	€/t	395	474	
	€/kWh	0.034	0.040	
	€/GJ	9.3	11.2	
Diesel	€/l	0.47	0.55	
	€/kWh	0.047	0.055	
	€/GJ	13.2	15.2	

The crude oil prices have been derived from the 'World Energy Outlook 2018' published by the International Energy Agency (IEA) [IEA 2018]. The crude oil price development for the scenario 'sustainable development' has been selected. Analogous [IEA 2018] the exchange rate has assumed to be 0.89 € per US$.

The costs for diesel include refining, transport, and dispensing. According to [JEC 2007] the costs for crude oil refining amounts to about 30% of the energy related crude oil price at a crude oil price of 50 € per bbl or about 2.6 € per GJ of diesel. The crude oil input for crude oil refining amounts to about 1.107 MJ per MJ of diesel leading to crude oil costs of about 10.3 GJ per GJ of diesel in 2020 and 12.4 € per GJ of diesel in 2030.

The costs for transport, distribution, and dispensing of the final fuel amount to about 0.2 € per GJ of diesel.

In the last 15 years the crude oil price showed extremely high fluctuations between 40 and 120 US$ per bbl [IEA 2018].

3.2.2 CNG/LNG from natural gas (reference)

Natural gas is extracted, processed, and transported to the EU via pipelines. Within the EU the natural gas is distributed to the refuelling stations via the high pressure and the local natural gas grid where it is dispensed to the trucks as CNG.

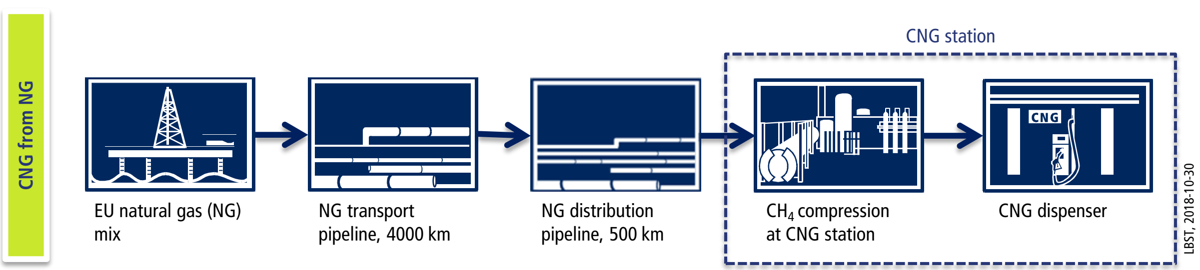


Figure 19: Pathway diagram of CNG supply from import of natural gas (fossil comparator)

Natural gas is extracted, processed, and transported to the EU via pipelines. Within the EU the natural gas is distributed to the refueling stations via the high pressure and the local natural gas grid. Onsite the refueling station the natural gas is liquefied and dispensed to the trucks as LNG.

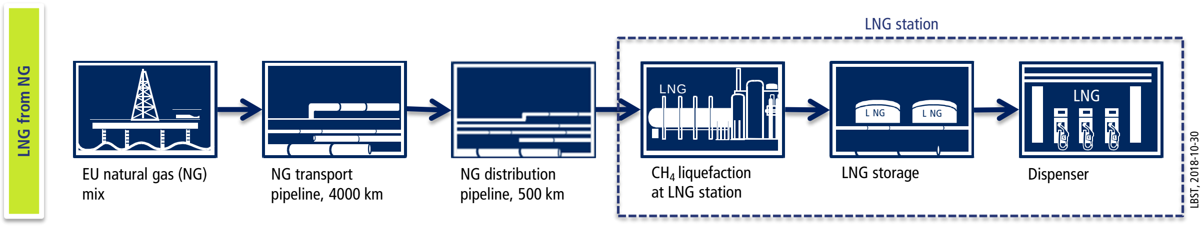


Figure 20: Pathway diagram of LNG supply from import of natural gas (fossil comparator)

Analogous to [JEC 2014] a transport distance of 4,000 km has been assumed for the supply of marginal natural gas. The energy requirements and greenhouse gas emissions for the supply of natural gas are based on data in [JEC 2014].

Analogous to [JEC 2007] the price of natural gas at EU border is assumed to be 80% of that of the price of crude oil based on the lower heating value (LHV) leading to the natural gas prices shown in Table 6.

Table 6: Crude oil price and resulting natural gas price at EU border

	Unit	2020	2030	Reference
Crude oil	US$/bbl	60	72	IEA 2018
	€/bbl	53	64	
	€/t	395	474	
	€/kWh	0.034	0.040	
	€/GJ	9.3	11.2	
Natural gas	€/kWh	0.027	0.032	
	€/GJ	7.5	9.0	

Based on German data, for natural gas distribution about 0.5 cent per kWh of natural gas and for natural gas storage about 0.4 cent per kWh of natural gas has been added leading to about 3.6 to 4.1 cent/kWh at the refuelling station.

The technical data for the natural gas liquefaction plant has been derived from [Galileo 2013].

The investment for the natural gas liquefaction plant has been derived from a plan in Norway built at Snurrevarden in Karmøy in Norway in 2003. The investment amounted to about 85 million Norwegian krone (kr) [OED 2003]. The investment has been converted from kr_{2003} to $€_{2015}$ via the exchange rates (US$/kr) of the time of publication (3003), the Chemical Engineering Plant Cost Index (CEPCI), and the exchange rate (€/US$) of 2015. The investment for the plant has been scaled to the required capacity using a scaling exponent of 0.7. The capacity is adapted to the fuel output of the LNG refuelling station.

According to manufacturers of such plants the costs for maintenance and repair amount to about 4% of the investment.

Table 7 shows the technical and economic data for the natural gas liquefaction plant onsite the LNG refuelling station.

Table 7: Technical and economic data for NG liquefaction onsite the LNG refuelling station

Parameter	Value
Capacity	2.63 MW_{LNG}
Equivalent full load period	8500 h
Electricity consumption	0.0605 kWh/kWh_{LNG}
	0.84 kWh/kg_{LNG}
Propane	0.000139 kg/kg_{LNG}
Lubricants	0.00024 l/kg_{LNG}
Investment	2.66 million €
Maintenance & repair	4% of investment/yr

The technical and economic data for the CNG and LNG refuelling station shown in Table 8 have been derived from [LBST 2016] except the electricity consumption which has been derived from [JEC 2014].

Table 8: CNG and LNG refuelling station

Parameter	Unit	CNG	LNG
Fuel output	GWh/yr	22.4	22.4
Electricity consumption	$kWh/kWh_{final\ fuel}$	0.022	0.000055
Number of dispensers	-	2	2
Investment	**€**	**1,843,000**	**1,034,000**
Gas inlet line incl. gas drier	€	120,000	-
Dispenser	€	100,000	189,000
Sequencing block for dispensers	€	16,000	-
LNG storage	€	-	145,000
Cryopump incl. valves and controller	€	-	129,000
CNG storage (3-bank)	€	175,000	20,000
Compressors (for boil-off in case of LNG)	€	450,000	25,000
Cooling system for compressors	€	30,000	-
Recirculation cooling cycle	€	25,000	-
Control unit for compressors	€	80,000	-
Odorisation (boil-off in case of LNG)	€	30,000	26,000
Equipment for data transfer	€	10,000	10,000
Concrete made building	€	100,000	-
Gas outlet line	€	35,000	-
MF-Block PF	€	10,000	-
Installation	€	150,000	-
Civil work (roof, pay system)	€	280,000	400,000
Cables, piping, material transport, calibration	€	120,000	-
Project management, documentation	€	80,000	80,000
Other	€	30,000	-
Approval	€	2,000	10,000
Maintenance, consumables & safety inspection			
Maintenance	€/yr	4902	20050
Spare parts	€/yr	-	4000
N_2	€/yr	-	5200
Safety inspection storage vessels	€/yr	2880	-
Dispenser calibration	€/yr	1432	1432

Table 9 shows the greenhouse gas emissions from the supply of CNG and LNG from piped natural gas.

Table 9: Greenhouse gas emissions from the supply of CNG and LNG from natural gas

Process step	CNG (g $CO_{2eq}/MJ_{final\ fuel}$)		LNG (g $CO_{2eq}/MJ_{final\ fuel}$)	
Time horizon	2020	2030	2020	2030
NG extraction and processing	4.1	4.1	4.1	4.1
Long distance pipeline	8.1	8.1	8.1	8.1
Local NG grid	0.5	0.5	0.5	0.5
NG liquefaction (onsite)	-	-	1.3	0.6
Refuelling station	2.7	0.2	0.0	0.0
Well-to-tank total	15.4	12.9	14.0	13.3

For time horizon 2020 the combustion of natural gas leads to about 55.1 g of CO_2 per MJ. As a result the supply and use of LNG from piped natural gas and liquefaction onsite the refuelling station leads to about 70.5 g of CO_2 equivalent per MJ (2030: 68.0 g CO_2 equivalent/MJ). The supply and use of CNG from piped natural gas leads to about 69.1 g of CO_2 equivalent per MJ (2030: 68.4 g CO_2 equivalent/MJ).

3.2.3 Hydrogen from natural gas (reference)

Two variants have been assessed. On variant where the hydrogen is generated in a central steam methane reforming (SMR) plant and on variant where the hydrogen is generated via steam methane reforming onsite the refueling station.

Central SMR: Natural gas is extracted, processed, and transported to the EU via pipelines. Within the EU the natural gas is distributed to a central steam methane reforming plant via the high pressure grid. The hydrogen leaving the central natural gas steam reforming plant is distributed to the refueling stations via a hydrogen pipeline grid, compressed at the refueling station and then dispensed to the trucks as CGH_2.

SMR onsite: Natural gas is extracted, processed, and transported to the EU via pipelines. Within the EU the natural gas is distributed to the refueling stations via the high pressure and the local natural gas grid. At the refueling station the natural gas is converted to hydrogen via steam reforming, compressed and then dispensed to the trucks as CGH_2.

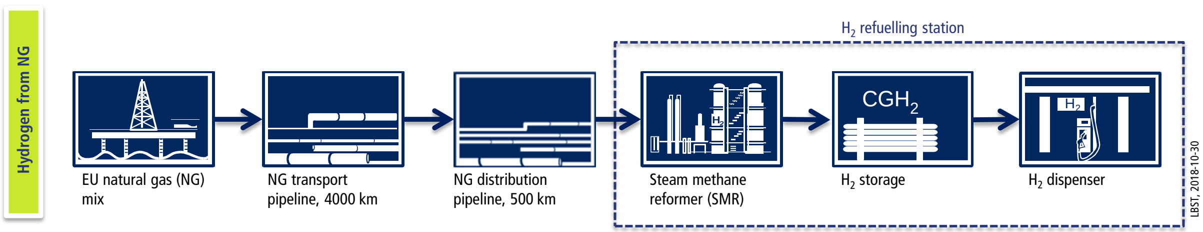


Figure 21: Pathway diagram of compressed gas hydrogen supply from natural gas (fossil comparator)

Analogous to [JEC 2014] a transport distance of 4,000 km has been assumed for the supply of marginal natural gas. The energy requirements and greenhouse gas emissions for the supply of natural gas are based on data in [JEC 2014].

Steam methane reforming is a mature technology and has been used for hydrogen generation since many decades. The technical and economic data for the central steam reforming plant have been derived from [Foster Wheeler 1996]. The technical and economic data for the steam methane reforming plant for onsite hydrogen generation have been derived from [Haldor Topsoe 1998]. The investment has been converted to €$_{2015}$ via the Chemical Engineering Plant Cost Index (CEPCI). Table 10 shows the technical and economic data for the steam methane reforming plants.

Table 10: Technical and economic data for steam methane reforming (SMR) plants

Parameter	Unit	Central SMR	SMR onsite
Capacity	Nm³/h	281,313	560
	MW_{CGH2}	844	1.68
NG consumption	kWh/kWh_{CGH2}	1.315	1.441
Electricity consumption	kWh/kWh_{CGH2}	-	0.0161
Water consumption	kg/kWh_{CGH2}	0.135	0.135
Lifetime	yr	25	15
Equivalent full load period	h/yr	8000	6000
Investment	million €	345	2.73
Labor, overhead	million €/yr	0.98	-
Maintenance & repair	million €/yr	3.93	0.027

The technical and economic data for the hydrogen pipeline grid shown in Table 11 have been derived from [Krieg 2012]. The lengths of the pipeline have been adapted to the number of refueling stations, and the amount of fuel to be dispensed to the trucks assumed in this study (about 31 TWh/yr in 2030). In this study a simplified approach has been applied using only two pipeline types (100 mm and 400 mm).

The investment for the compressors has been neglected. According to [Krieg 2012] the share of compressor costs for a comprehensive hydrogen pipeline grid calculated for Germany is 13% of the total investment.

Table 11: Hydrogen pipeline grid

	Unit	2020	2030
H_2 throughput	TWh/yr	0.32	31
Electricity consumption	kWh/kg$_{H2}$	0.6	0.6
	kWh/kWh$_{H2}$	0.018	0.018
Lengths main pipelines	km	100	4000
Inner diameter main pipelines	mm	400	400
Investment main pipelines	€/m	826	826
	million €	82.6	3304
Lengths local pipelines	km	50	12000
Inner diameter local pipelines	mm	100	100
Investment main pipelines	€/m	352	352
	million €	17.6	4224
Investment H_2 pipeline grid total	million €	100.2	7528
Lifetime pipeline grid	yr	30	30
Maintenance & repair	million €/yr	0.75	80
Costs of H_2 distribution	€/kgH2	0.73	0.60
	€/kWhH2	0.022	0.018

The assumptions for the time horizon 2030 lead to about 0.6 kWh per kg of hydrogen or 1.8 cent per kWh of hydrogen based on the lower heating value (LHV). In [Krieg 2012] the costs of hydrogen distribution via pipeline grid is indicated with about 0.79 € per kg of hydrogen. However, in [Krieg 2012] a higher interest rate (10%) has been assumed than in this study (4%). At an interest rate of 10% and the assumptions presented in Table 11 would lead to about 0.99 € per kg of hydrogen for distribution via pipeline grid in 2030.

The technical and economic data for the CGH_2 refueling station have been derived from [Parks et al. 2014]. Many cost data used by [Parks et al. 2014] came from the EU. An exchange of 1.35 US$ per € has been assumed in [Parks et al. 2014]. This value has been used in this study to convert the US$ back to €. In [Parks et al. 2014] the cost data from US$$_{2012}$ has been converted to US$$_{2007}$ using a factor of 0.894. As a result, the cost data in [Parks et al. 2014] are presented in US$$_{2007}$. To trace back to €$_{2012}$ the factor of 1.35*1/0.894 has been applied. Learning curves have been applied to consider cost reduction from series production.

The CGH_2 refueling stations are capable to refuel heavy duty vehicles with 70 MPa vehicle tanks. The capacity of the high pressure buffer has been increased compared to [Parks et al. 2014] for the refueling of tractor trucks instead of passenger vehicles.

The suction pressure (i.e. the pressure of the hydrogen delivered from the pipeline or the onsite hydrogen generation plant) is assumed to be 2 MPa. The maximum pressure of the intermediate bulk storage is 17.2 MPa in today's layout and 25 MPa in a future layout [Parks et al. 2014]. The compression ratio would be 8.6 and 12.5. Generally the compression ratio per stage should not be more than 3 to 4. Therefore, a multi-stage compressor system is required. To calculate the energy requirement for a multi-stage compressor system the compression ratio for each stage is required. The compression ratio can be calculated by

$$CR = \left(\frac{p_d}{p_s}\right)^{\frac{1}{n}}$$

Where:

CR	Compression work per stage
p_s	Suction pressure in MPa
p_d	Discharge pressure in MPa
n	Number of compression stages

In case of a two-stage compressor system the compression ratio would be about 2.9 in case of a hydrogen storage system with a maximum pressure of 17.2 MPa and about 3.5 for a stationary hydrogen storage with a maximum pressure of 25 MPa.

The compression work for a real gas the compressibility factors have been taken into account via the average compressibility factor at suction and discharge pressure.

Then, the compression work can be calculated by

$$W_{comp} = \frac{\kappa}{\kappa - 1} R \cdot T_s \left[(CR)^{\frac{\kappa-1}{\kappa}} - 1 \right] + (n-1) \frac{\kappa}{\kappa - 1} R \cdot T_{IC} \left[(CR)^{\frac{\kappa-1}{\kappa}} - 1 \right] \cdot \frac{z_s + z_d}{2}$$

Where:

W_{comp}	Compression work in J per mole of H_2
κ	Isentropic exponent of the gas (H_2: 1.409)
R	Gas constant (8.314 kJ/(mol*K))
T_s	Temperature of the gas at suction pressure in K (assumption: 288 K)
T_{IC}	Temperature of the gas after intercooling in K (assumption: 333 K)
CR	Compression work per stage
n	Number of compression stages
z_s	Gas compressibility factor at suction pressure
z_d	Gas compressibility factor at discharge pressure

For the calculation of the electricity requirement the compressor efficiency and the efficiency of the electric motor have to be taken into account. To convert the electricity consumption from J per mole of hydrogen to kWh per Nm³ of hydrogen the molar volume of hydrogen is required. The molar volume of every gas amounts to about 22.4 l at normal conditions (T = 273.15 K; p = 0.1013 MPa). Then, the electricity consumption for hydrogen compression can be calculated by

$$W_e = W_{comp} \cdot \frac{1}{\eta_{comp} \cdot \eta_{motor}} \frac{1000\, l/Nm^3}{22.4\, l/mole} \cdot \frac{1}{3600000\, J/kWh}$$

Where:

We	Electricity consumption in kWh per Nm³ of H_2
η_{comp}	Efficiency of the compressor (Parks et al. 2014: 65%)
η_{motor}	Efficiency of the electric motor (assumption: 90%)

To calculate the electricity consumption per kWh of hydrogen based on the lower heating value (LHV) the electricity requirement per Nm³ of hydrogen has to be divided by the LHV of hydrogen (3 kWh/Nm³).

In the layout of the refueling station used in this study the hydrogen is compressed to the maximum pressure of the bulk hydrogen storage. To refuel the high pressure buffer the compressor empties the bulk hydrogen storage and compresses the hydrogen to the maximum pressure of the high pressure buffer storage (about 88 MPa according to [Parks et al. 2014].

Pre-cooling is required to limit the temperature increase in the vehicle tank. An electricity consumption of 50 to 60 kWh per kg of hydrogen for cooling has been reported from EU early station operations [Elgowainy & Reddi 2015]. However, the electricity consumption can be significantly decreased. One reason for the extremely high electricity consumption for pre-cooling in the past was, that the technology was in a very early stage of development and not optimized. Another reason was the low utilization of the hydrogen refueling stations. According to [Elgowainy & Reddi 2015] the electricity consumption for pre-cooling can be calculated by

$$W_e \approx \frac{0.3 + \frac{54}{daily\ dispensed\ kg\ H2}}{COP}$$

Where:

W_e	Electricity consumption per kg of hydrogen
COP	Coefficient of performance (= 1.2 @ 15°C ambient temperature)

For a daily dispensed amount of hydrogen of 300 kg the electricity consumption for the refueling station would be about 0.4 kWh per kg or about 0.012 kWh per kWh of hydrogen based on the lower heating value (LHV). For 1000 kg of hydrogen per day the number will decrease to about 0.3 kWh per kg or about 0.009 kWh per kWh of hydrogen based on the LHV.

In [Kampitsch 2012] the electricity consumption for pre-cooling has been indicated with 3 kWh per kg of hydrogen (2 kWh per kg at idle + 1 kWh per kg from vehicle refueling). In this study the 3 kWh per kg of hydrogen (0.090 kWh/kWh of hydrogen) his number has been used for the time horizon 2020. A manufacturer indicates an electricity consumption of 0.2 to 0.4 kWh/kg of hydrogen (0.006 to 0.012 kWh/kWh of hydrogen).For 2030 the 0.4 kWh per kg (0.012 kWh/kWh of hydrogen) has been assumed as a conservative estimate.

There are various hydrogen refueling concepts concerning the layout and operation of the stationary hydrogen storage. In this study a simplified system consisting of a bulk hydrogen storage system with moderate pressures and a multi-bank high pressure buffer storage system has been selected.

Table 12 shows the electricity consumption for hydrogen compression and pre-cooling.

Table 12: Electricity consumption CGH_2 refuelling station for H_2 delivery via pipeline

	Unit	2015	2020	2030
Primary compression (loading bulk H_2 storage)				
Number of stages		2	2	2
Isentropic coefficient		1.409	1.409	1.409
Temperature H_2 input	K	288	288	288
Temperature after intercooling	K	333	333	333
p (suction)	MPa	20	20	20
p (discharge)	MPa	17.2	25.0	25.0
Pressure ratio	per stage	2.9	3.5	3.5
Compression energy	J/mole	6737	8249	8249
Compressor efficiency		65.0%	65.0%	65.0%
Electric motor efficiency		90%	90%	90%
Electricity requirement	kWh/Nm^3_{H2}	0.143	0.175	0.175
	kWh/kWh_{H2}	0.048	0.058	0.058
Secondary compression (loading high pressure buffer from bulk H_2 storage)				
Number of stages		2	2	2
Temperature H_2 input	K	288	288	288
Temperature after intercooling	K	333	333	333
p (suction)*	MPa	11.0	13.2	13.2
p (discharge)	MPa	88.0	88.0	88.0
Pressure ratio	per stage	2.8	2.6	2.6
Compression energy	J/mole	7392	6656	6656
Compressor efficiency		65.0%	65.0%	65.0%
Electric motor efficiency		90%	90%	90%
Electricity requirement	kWh/Nm^3_{H2}	0.157	0.141	0.141
	kWh/kWh_{H2}	0.052	0.047	0.047
Subtotal	**kWh/kWh_{H2}**	**0.100**	**0.105**	**0.105**
Precooling	kWh/kWh_{H2}	0.190	0.090	0.012
Total	**kWh/kWh_{H2}**	**0.290**	**0.195**	**0.117**

* Average suction pressure for unloading the bulk hydrogen storage

Table 13 shows the summarized technical and economic data for the refueling stations. The investment for 2020 and 2030 represents the average investment including the first and the last unit.

Table 13: CGH_2 refuelling station for H_2 delivery via pipeline

	Unit	2014*	2020	2030
Fuel output	GWh/yr	12.2	12.2	12.2
	kg/d	1000	1000	1000
Number of dispensers	-	2	2	2
Electricity consumption	**kWh/kWh_{CGH2}**	**0.290**	**0.195**	**0.117**
H_2 compression	kWh/kWh_{CGH2}	0.100	0.105	0.105
Pre-cooling	kWh/kWh_{CGH2}	0.190	0.090	0.012
Investment	**€**	**3,732,000**	**3,150,000**	**2,323,000**
H_2 bulk storage (40% of daily demand)	€	549,000	309,000	245,000
H_2 high pressure buffer	€	711,000	674,000	534,000
H_2 compressors	€	781,000	703,000	445,000
Pre-cooling	€	188,000	178,000	141,000
H_2 dispenser	€	157,000	148,000	118,000
Installation	€	716,000	604,000	445,000
Site preparation	€	155,000	131,000	96,000
Engineering & design	€	310,000	262,000	193,000
Contingency	€	155,000	131,000	96,000
Approval	€	10,000	10,000	10,000
Maintenance, safety inspection				
Maintenance & repair	€/yr	15,627	14,062	8,900
Safety inspection storage vessels	€/yr	1,020	825	825
Dispenser calibration	€/yr	1,432	1,432	1,432

In case of hydrogen from onsite steam methane reforming the electricity consumption for hydrogen compression is slightly higher due to the higher temperature at the hydrogen (313 K = 40°C for hydrogen leaving the pressure swing adsorption plant instead of 288 K = 15°C leaving the H_2 pipeline).

3.2.4 Electricity for catenary from French grid mix (reference)

Electricity from the French grid mix is distributed via the high voltage and medium voltage to the substations along the motorway where the electricity is converted to direct current for the catenary system. Electricity storage systems based on lithium-ion batteries are installed to avoid peaks in the electricity grid. As a back-up for vehicle operation outside the catenary system and low state of charge (SOC) of the on-board battery chargers are installed at the home base of the trucks.

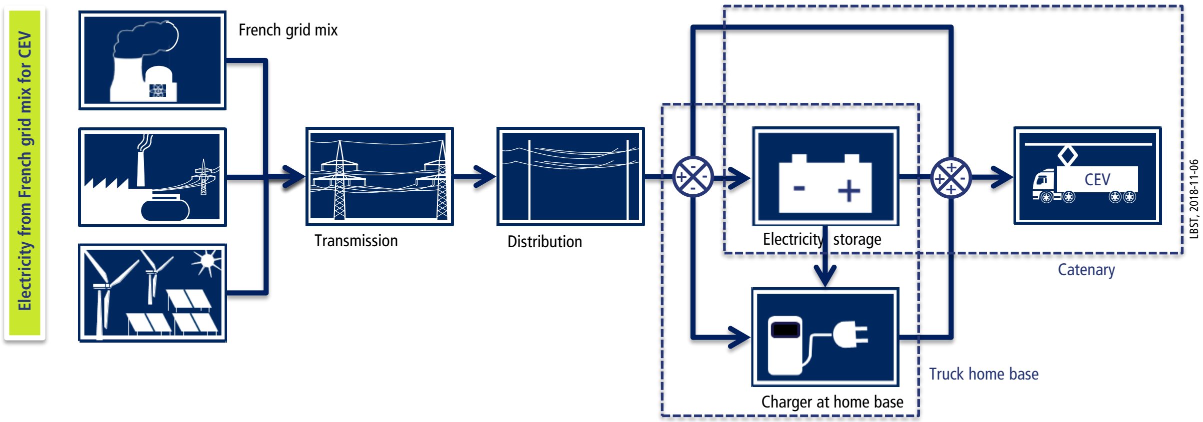


Figure 22: Pathway diagram of CEV electricity supply from French grid mix

For time horizon 2020 today's the French electricity mix has been derived from today's grid mix in France from [RTE 2018a]. It has been assumed that coal power stations are decommissioned until 2020 and replaced by electricity from wind and solar energy.

For 2030 it has been assumed that the share of nuclear electricity decreases to about 50% and the share of renewable electricity increased to about 40% (hydro remains constant, other renewable mainly consists of wind power and photovoltaic). In 2030 natural gas is only used in combined heat and power (CHP) plants leading to lower greenhouse gas emissions for electricity from natural gas. Fuel oil use is phased out.

Table 14: Electricity mix in France

	2020	2030
Nuclear	71.6%	50%
Natural gas	7.9%	10%
Fuel oil	0.7%	-
Hydro	10.1%	10%
Wind	5.4%	15%
Solar	2.6%	15%
Biomass	1.7%	-
GHG emissions w/o transport and distribution	67 g CO_{2eq}/kWh_e	30 g CO_{2eq}/kWh_e

The greenhouse gas emissions from electricity supply include the supply of nuclear, fossil and biomass derived fuel.

The efficiency for electricity transport and distribution shown in Table 15 has been derived from [Itten et al. 2014].

Table 15: Efficiency of electricity transport and distribution

Voltage level	Step	Cumulative
Ultra-high voltage (UHV), high voltage (HV)	94.1%	94.1%
Medium voltage (MV)	99.0%	93.2%
Low voltage (LHV)	90.6%	84.4%

According to [Enedis 2017] the electricity costs without transport and distribution amounts to 5.4 cent/kWh. The substations along the motorway are connected with the medium voltage (MV) grid. The efficiency of electricity transport and distribution amounts to about 93.2% leading to about 5.8 cent/kWh for electricity generation at plant gate. From the data in [RTE 2018b] (Tarif d'Utilisation des Réseaux Publics d'Électricité – TURPE) costs for electricity transport and distribution of 2.0 cent/kWh can be calculated (Table 16). As a result the electricity cost at the input of the substation at catenary system amounts to about 7.8 cent/kWh.

Table 16: Costs of electricity transport and distribution using domestic renewable electricity (> 4000 h/a; 1 kV < x ≤ 40 kV; flat peak tariff)

Costs of electricity transport and distribution using domestic renewable electricity (> 4000 h/a; 1 kV < x ≤ 40 kV; flat peak tariff)							20 MW	
		Peak hours	High season peak hours	High season off-peak	Low season peak hours	Low season off-peak		
Demand rate		PS1	PS2	PS3	PS4	PS5	Total/installed	
bi	€/(kW*yr)	15.7	15.16	12.79	8.42	1.61		RTE 2018, p. 13
Power demand	kW	1,000	1,000	1,000	1,000	1,000	1,000	
	€/yr	15,700	0	0	0	0	15,700	
	€/kWh						0.004	
Energy rate		E1	E2	E3	E4	E5	Total	
ci	cent/kWh	2.74	2.06	1.28	0.95	0.84		RTE 2018, p. 13
Duration time ranges PS1 to PS5	h/yr	131	749	968	1247	1371	4465	
Electricity demand	kWh	131,067	748,536	967,562	1,246,588	1,371,247	4,465,000	
	€/yr	3,591	15,420	12,385	11,843	11,518	54,757	
	€/kWh						0.012	
Costs of electricity transport total	€/kWh						**0.020**	

The equipment for the catenary infrastructure is similar to that of trolley buses. However, the speed is higher in case of long-haul trucks cruising on a motorway. In contrast to railways two overhead wires are required per track. The traction power is supplied by substations consisting of switching systems and a transformer that converts the alternate high voltage current of the grid to low direct current (typically between 600 and 1500 V) which flows into the catenary [CE Delft & DLR 2013]. Every 2 to 3 km a substation is required.

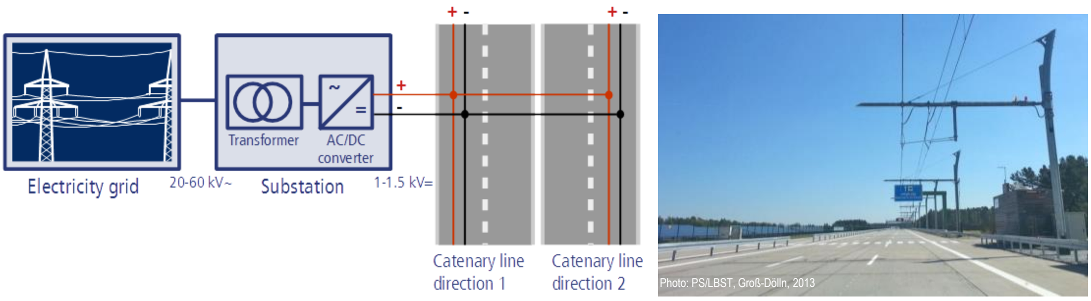


Figure 23: Basic electrical layout (left image by LBST based on [ISI et al. 2017]) and prototype catenary infrastructure in Germany (right image by LBST)

The efficiency of the catenary system is assumed to be 90%. As a result the costs for electricity at the pantograph of the catenary truck amounts to about 8.7 cent/kWh without the catenary infrastructure costs.

It has been assumed that in 2020 an initial catenary infrastructure on one motorway between Paris and Lille (autoroute A1) with a length of 211 km will be installed at an investment of about 350 million € serving 1137 catenary trucks. Until 2030 the catenary infrastructure will be expanded to 3,900 km serving about 129,000 catenary trucks. The cumulative investment in 2030 will be 33 billion €. The initial catenary infrastructure in 2020 has not stationary electricity storage. The stationary electricity storage will be introduced with the expansion of the catenary infrastructure until 2030.

The technical and economic data for the catenary infrastructure without stationary electricity storage shown in Table 17 have been derived from [ISI et al. 2017].

Table 17: Technical and economic data for catenary infrastructure without stationary electricity storage

Parameter	Unit	2020 (211 km)	2030 (3900 km)
Distance entry points	km motorway	3	3
Investment entry points	€/entry point	15,000	15,000
	€/(km motorway)	5,000	5,000
Length feed line to entry point	km cable	1.5	1.5
Investment feed line	€/(km cable)	225,000	225,000
	€/(km motorway)	112,500	112,500
Power requirement substation	MVA/substation	3	25
Investment substation	€/MVA	300,000	300,000
	€/(km motorway)	300,000	2,500,000
Power poles	m motor way/power pole	50	50
Investment power poles	€/power pole	10,000	10,000
	€/(km motorway)	400,000	400,000
Investment catenary (overhead wire)	€/(m wire)	300	300
	€/(km motorway)	600,000	600,000
Investment passive protection equipment	€/(m wire)	50	50
	€/(km motorway)	100,000	100,000
Total component costs	€/(km motorway)	1,517,500	3,717,500
Engineering, overhead	of component cost	10%	10%
Investment total	€/(km motorway)	1,669,250	4,089,250
	billion €	0.352	15.9
Maintenance & repair	of component cost	2%	2%

In the beginning of the rollout only a few catenary trucks uses the catenary infrastructure. Therefore, the capacity of the substations is lower leading to lower specific investment than for full deployment in 2030. For the initial catenary infrastructure the required investment amounts to about 1.7 million € per km of motorway. After expansion to 3900 km the specific investment will be about 4.1 million €.

The cost data for the stationary electricity storage have been derived from [Electrek 2016]. The stationary electricity storage system consists of lithium-ion batteries, inverter, cabling, site support, and other hardware. For 2030 it has been assumed that the costs for the electricity storage system decreases at about 5% per year from 2015 (date of publication of the cost data) and 2030.

Table 18 shows the summarized technical and economic data of the catenary infrastructure including stationary electricity storage.

Table 18: Summarized technical and economic data of the catenary infrastructure including stationary electricity storage

Parameter	Unit	2020	2030
Number of trucks	-	1137	128,802
Electricity demand	TWh/yr	0.191	18.4
Length	km	211	3900
CAPEX catenary infrastructure without electricity storage	€/(km motorway)	1,699,250	4089,250
	billion €	0.352	15.9
Required power electricity storage	GW	-	26
CAPEX electricity storage	€/kWh	726	336
	€/kW	1451	672
	billion €	-	17.5
CAPEX catenary infrastructure total	billion €	-	33.4

Furthermore, a charger at the home base of the truck has to be considered. The investment for a charger for the charging of heavy duty vehicles amounts to about 30,950 € [ABB 3/2017] and [ABB 4/2017]. The costs for maintenance and grid connection is indicated with 3400 € per year and charger [ABB 3/2017]. However, the costs for the charger have been considers as part of the vehicle costs. The electricity costs 'well-to-tank' or 'well to pantograph' respectively does not include the cost of the charger at the home base.

3.2.5 Diesel via power-to-liquid from French nuclear power (low carbon)

Electricity is generated in a newly built nuclear power station and transported to a power-to-liquid plant which consists of low temperature water electrolysis, H_2 buffer storage, a direct air capture of CO_2 (DAC), CO_2 liquefaction, CO_2 buffer storage, H2 and CO_2 compressors, Fischer-Tropsch syntheses, and upgrading of the liquid hydrocarbons to gasoline, kerosene and diesel. The diesel is transported to a depot via train, pipeline, and ship. From there, the diesel is transported to the refueling stations where it is dispensed to the trucks.

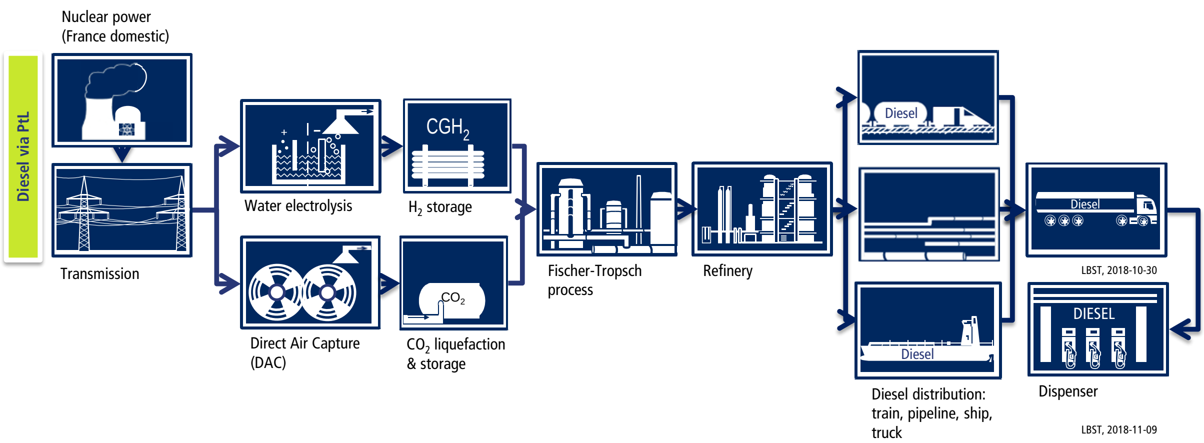


Figure 24: Pathway diagram of PtL Diesel supply from French nuclear power

The technical and economic data of the nuclear power plant shown in Table 19 are based on the European Pressurized Reactor (EPR) which is currently under construction in Flamanville.

Table 19: Nuclear power station

Parameter	Value	Reference
Net electricity generation capacity	1650 MW_e	
Equivalent full load period	8056	[Areva 2014]
Efficiency	37%	[Areva 2014]
Electricity generation	13.3 TWh/yr	
Investment	10.9 billion €	[WNN 2018]
Lifetime	60 yr	[CourDeComptes 2012]
Fuel costs	40.3 million €/yr	[WNA 2018], [Areva 2014]
Financial charges of the inventory	14.9 million €/yr	[CourDeComptes 2012]
Nuclear waste disposal	31.3 million €/yr	[CourDeComptes 2012]
Last core	2.5 million €/yr	[CourDeComptes 2012]
Labor	56.8 million €/yr	[CourDeComptes 2012]
Pension reform & LT employee benefits	14.4 million €/yr	[CourDeComptes 2012]
Agent rate	3.2 million €/yr	[CourDeComptes 2012]
Overhead, central and support services	24.3 million €/yr	[CourDeComptes 2012]
Maintenance	102.0 million €/yr	[CourDeComptes 2012]
External consumptions (spare parts)	58.3 million €/yr	[CourDeComptes 2012]
Other costs and revenues	1.7 million €/yr	[CourDeComptes 2012]
Decommissioning	16.7 million €/yr	[WNA 2018]
Total	848.0 million €/yr	
	0.0638 cent/kWh	

Based on the assumption in this study the cost of nuclear electricity amounts to about 6.4 cent per kWh or 64 € per MWh. This has to be compared with the statement in [CourDeComptes 2012] where electricity costs of 70 to 90 € per MWh are indicated:

> *«In view of the lengthening lead times, which would suggest a higher amount for the interest during the construction, and in view of the increase in the cost of the construction since then, it can be estimated that the future production cost of Flamanville will be from €70 per MWh to €90 MWh, with a service life of 60 years. However, these items should be taken with considerable precaution because they are not based on an analysis conducted by the Cour des Comptes on a precise estimate proposed by EDF. It should also be remembered that these costs are not the costs for a standard EPR, for which costs should be lower but are even more difficult to forecast»*

However, the result from the calculation of the cost of nuclear electricity is below the lower limit of the 7 to 9 cent per kWh indicated in [CourDeComptes 2012].

The electricity is transported via the electricity grid to the power-to-liquid plant. Table 20 shows the costs for electricity transport via the high voltage electricity grid based on data in [RTE 2018b].

Table 20: Costs of electricity transport and distribution using domestic nuclear electricity (>4000 h/yr; 130 kV < x < 350 kV)

Costs of electricity transport and distribution for large-scale PtX plant using nuclear electricity (>4000 h/yr; 130 kV < x < 350 kV)							500 MW	
		Peak hours	High season peak hours	High season off-peak	Low season peak hours	Low season off-peak		
Demand rate		PS1	PS2	PS3	PS4	PS5	Total/installed	
bi	€/(kW*yr)	12.13	11.65	9.68	7.54	3.73		RTE 2018, p. 29
Power demand	kW	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	
	€/yr	12,130,000	0	0	0	0	12,130,000	
	€/kWh						0.002	
Energy rate		E1	E2	E3	E4	E5	Total	
ci	cent/kWh	0.83	0.61	0.43	0	0		RTE 2018, p. 29
Duration time ranges PS1 to PS5	h/yr	237	1351	1746	2250	2475	8059	
Electricity demand	kWh	236,571,429	1,351,085,714	1,746,422,857	2,250,057,143	2,475,062,857	8,059,200,000	
	€/yr	1,963,543	8,241,623	7,509,618	0	0	17,714,784	
	€/kWh						0.002	
Costs of electricity transport total	€/kWh						**0.008**	

The efficiency for low temperature electrolysis shown in Table 21 has been derived from [DLR et al. 2015] and is based on proton exchange membrane (PEM) electrolysis cells. The electricity consumption includes all auxiliaries such as AC/DC inverter, pumps, and blowers. The efficiency of alkaline electrolysis plants is approximately the same.

Table 21: Efficiency H_2 production via water electrolysis

	Unit	2020	2030
Electricity consumption	kWh/Nm³	5.08	4.22
	kWh/kg	56	47
	kWh/kWh_{LHV}	1.693	1.407
Usable heat generation (60°C)	kWh/kWh_{LHV}	-	0.109
Efficiency LHV	-	59.1%	71.1%
Efficiency HHV	-	69.8%	84.0%

For the comparison with other studies (e.g. [Fasihi et al. 2016]) or data sheets from manufactures it has always to be checked whether the lower heating value (LHV) or the higher heating value (HHV) has been used. In case of hydrogen the ratio between HHV and LHV is about 1.182. In this study the energy use is based on the LHV.

Like for photovoltaic plants it can be expected that the specific CAPEX of electrolysis plants decreases with the cumulative installed capacity due to series production. The learning curve for the electrolysis plants is based on a world-wide introduction of water electrolysis and is based on PEM technology (Figure 25).

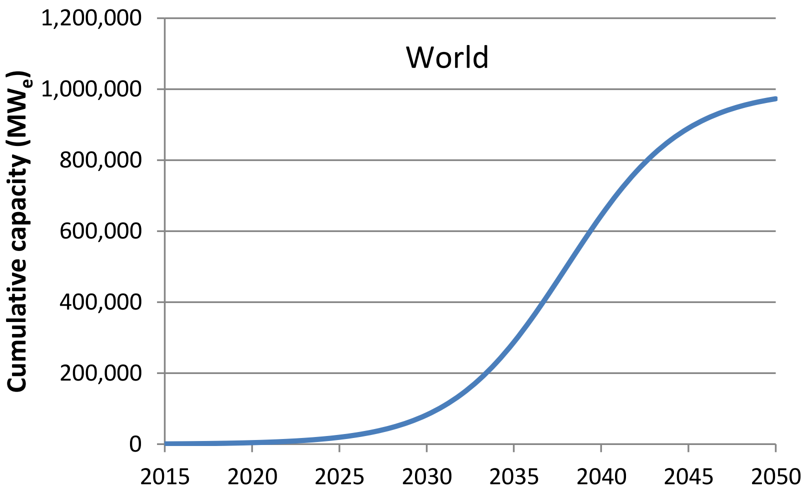


Figure 25: Development of cumulative water electrolysis capacity based on PEM technology in the world

Today, the specific CAPEX for a 5 MW_e electrolysis plant based on PEM electrolysis cells amounts to about 1200 €/kW_e based on the average of five quotations and one study [DLR et al. 2015]. For a larger plant with an installed capacity of 100 MW the CAPEX would decrease to about 700 €/kW (based on data in [DLR et al. 2015]).

Figure 26 shows a possible development of the specific CAPEX for the electrolysis plants which it has been assumed in this study.

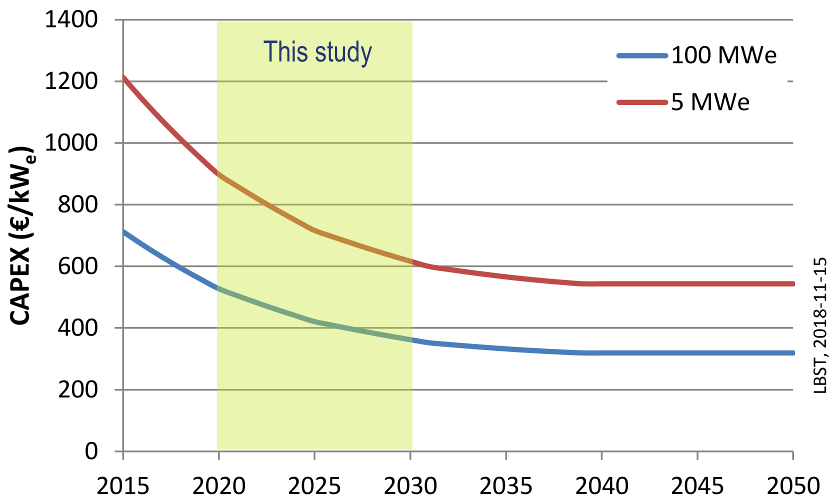


Figure 26: Development of specific CAPEX for water electrolysis based on PEM technology

In 2030 the specific investment for large (100 MW_e) electrolysis plants amounts to about 362 € per kW_e including building.

Electrolyser CAPEX has already decreased and can further significantly decrease even with modest up-scaling assumptions (per unit and by production volume) and a relatively small plant with 1 MW_e according to [Mayyas & Mann 2018]:

- 500 to 600 €/kW_e if 10 units are produced per year
- ~350 €/kW_e if 100 units are produced per year
- For 100 units per year the differences between the regions where the plants are produced are small

The Fischer-Tropsch plant is connected with an electrolysis plant with a capacity of 500 MW_e. The hydrogen leaving the electrolysis plant is compressed from 3.4 MPa to 10 MPa for stationary hydrogen storage. In case of nuclear electricity it has been assumed that the H_2 storage capacity is sufficient for one hour of full load operation.

The products consist of gasoline, kerosene, and diesel whereas the middle distillate fraction (kerosene and diesel) is considered as main products. Allocation by energy is applied to allocate the inputs to the products. The input and output data shown in Table 22 have been derived from [König et al. 8/2015].

Table 22: Input and output data of the Fischer-Tropsch plant

Parameter	I/O	Value	[König et al. 8/2015]
H_2	Input	1.4972 kWh/kWh$_{PTL}$	100.42 MW H_2
CO_2	Input	0.341 kg/kWh$_{PTL}$	22.85 t CO_2/h
Electricity	Input	0.0453 kWh/kWh$_{PTL}$	CO_2 compressor: 1.97 MW$_e$ Recycle compressor: 0.87 MW$_e$ Air blower: 0.19 MW$_e$ Wax pumps hydrocracker: 0.01 MW$_e$
Liquid FT products	Output	1.0000	67.08 MW of liquid products
Steam	Output	0.3259 kWh/kWh$_{PTL}$	21.86 MW steam

Liquid Fischer-Tropsch (FT) products are gasoline, kerosene, and diesel. The input and output data are allocated by energy to the different liquid FT products.

The plant consist of Fischer-Tropsch synthesis, reverse water gas shift (RWGS), hydrocracking, a fuel gas fired burner for the supply of high temperature heat for the RWGS, and the separation of products via distillation. The hydrocarbon chain growth probability α has been indicated with 0.85. For water electrolysis [König et al. 8/2015] has assumed an electricity consumption of 4.3 kWh per Nm³ of hydrogen (69.8% related to the LHV).

In this study the steam is used for heat supply for the direct air capture (DAC) plant for CO_2 supply.

The CAPEX of the Fischer-Tropsch plant without electrolysis, hydrogen, CO_2 liquefaction, and CO_2 storage has been derived from [Becker et al. 2012] and [König et al. 7/2015]. The CAPEX has been adjusted to the required capacity depending on electrolysis technology and time horizon using the scaling exponent for each component. Furthermore the US$2009 has been converted to US$2015 via the Chemical Engineering Plant Cost Index (CEPCI). For the conversion to € an exchange rate of 0.9019 €/US$ has been assumed (average exchange rate in 2015).

The capacity of the Fischer-Tropsch plants amounts to 197 MW of final fuel in 2020 and 237 MW of final fuel in 2030. Table 23 shows the CAPEX of the components of Fischer-Tropsch synthesis and further processing.

Table 23: CAPEX for Fischer-Tropsch plant

Component	Scaling exponent	[König et al. 7/2015] 27.8 MW_{PTL} (million US$)	2020 197 MW_{PTL} (million €)	2030 237 MW_{PTL} (million €)
Burner	1.00	4.99	34.07	41.00
FT reactor	1.00	3.11	21.23	25.55
RWGS	0.65	1.18	4.06	4.58
PSA	0.70	1.34	5.08	5.79
Distillation	0.70	0.47	1.78	2.03
Wax hydrocracker	0.70	4.31	16.35	18.61
Distillate hydrotreater	0.70	2.41	9.14	10.41
Naphtha hydrotreater	0.70	0.66	2.50	2.85
Catalytic reformer/platformer	0.70	3.55	13.46	15.33
C5/C6 isomerization	0.70	0.59	2.24	2.55
Total installed cost		**22.61**	**109.92**	**128.69**
Total direct cost		**25.32**	**123.11**	**144.13**
Engineering & design		3.29	16.00	18.74
Construction		3.55	17.23	20.18
Legal and contractor fees		2.28	11.08	12.97
Project contingency		3.80	18.47	21.62
Total indirect costs			62.78	73.51
Total CAPEX		**38.24**	**185.89**	**217.64**

CO_2 is required for the production of synthetic carbon containing fuels. Direct capture of CO_2 from air has been assumed in this study as CO_2 source as a conservative assumption, thus avoiding potential restrictions from biomass-based CO_2 and lock-in effects from fossil-based CO_2 uses.

The technical and economic data for the direct air capture (DAC) plant have been derived from the Swiss company Climeworks. The technology is based on temperature swing adsorption (TSA). The electricity consumption ranges between 0.2 and 0.3 kWh per kg of CO_2 [Climeworks 2015]. The heat consumption ranges between 1.5 and 2.0 kWh per kg of CO_2. The economic data supplied by the Swiss company Climeworks from 2015 are indicated in Swiss Franc (CHF) which has been converted to € using an exchange rate of 0.95 €/CHF. From the economic data also a curve for the specific investment depending on the capacity of the plant can be made (Figure 27).

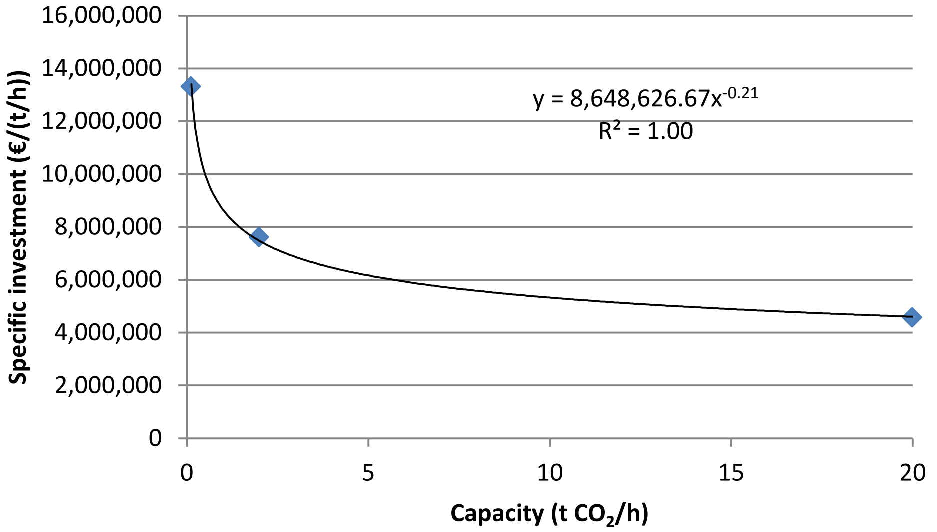


Figure 27: Specific investment for CO_2 capture from air via TSA

From this curve the investment for the CO_2 capture from air via TSA has been calculated. The maintenance costs have been assumed to be 2.5°% of investment per year. The extracted CO_2 is liquefied and sent to CO_2 storage. The electricity requirement for CO_2 liquefaction amounts to about 0.2 kWh per kg of CO_2. Table 24 shows the technical and economic data for CO_2 supply.

Table 24: CO_2 supply for Fischer-Tropsch plant

	Unit	2020	2030
Capacity	MW_{PTL}	197	237
Electricity consumption	kWh/kg_{CO2}	0.25 + 0.21	0.25 + 0.21
Heat consumption (T ≥95°C)	kWh/kg_{CO2}	1.75	1.75
CO_2 requirement	t/h	67.2 t/h	80.9
CAPEX DAC plant	million €	240	278
CAPEX CO_2 liquefaction & storage	million €	37	42
CAPEX CO_2 supply total	million €	277	320

The heat is partly supplied by the steam output of the Fischer-Tropsch plant. In 2030 it has been assumed that the heat demand for CO_2 extraction is almost completely supplied by heat from the Fischer-Tropsch plant and heat from the electrolysis plant analogous to [Fasihi et al. 2016] (Figure 28).

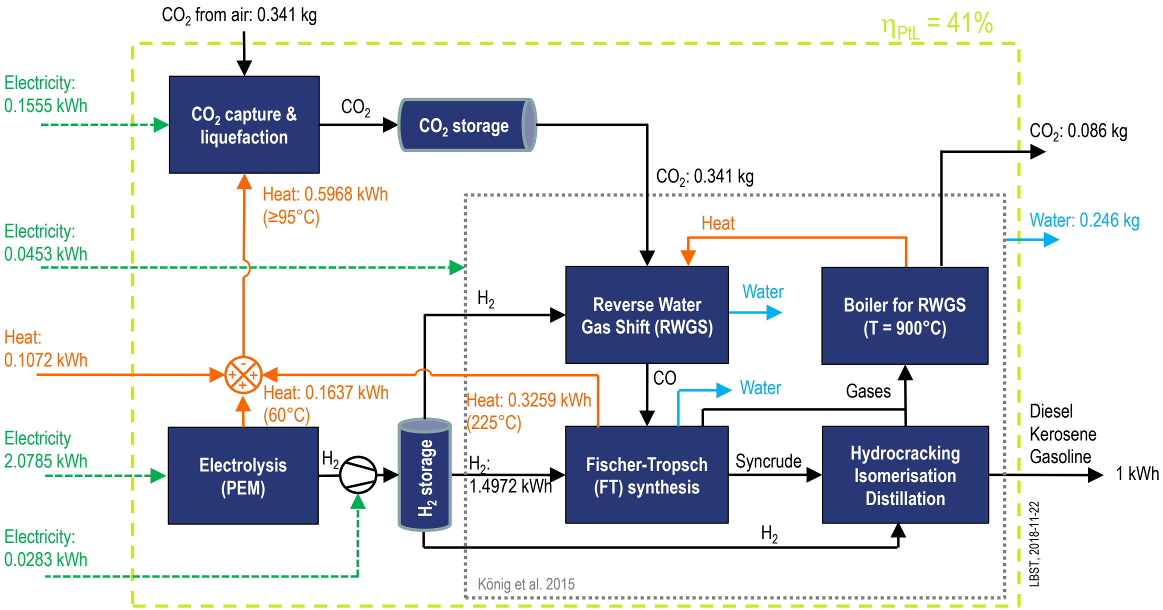


Figure 28: Energy streams of the Power-to-Liquid plant in 2030

Table 25 shows the fact sheet for the supply of synthetic diesel via power-to-liquid from nuclear electricity.

Table 25: Fact sheet: power-to-Liquid plant using nuclear electricity in France and costs of the supply of final fuel

	Unit	2020	2030
Technical key data			
Electricity input	MW_e	598	580
Fuel output	MW_{PtL}	197	237
Specific electricity input	MJ/MJ_{PTL}	3.03	2.44
Efficiency PtL plant		33%	41%
CO_2 demand (gross)	t/h	67.2	80.9
Equivalent full load period	h/yr	8059	8059
CAPEX			
Electrolysis	million €	264	181
H_2 compression & storage (1 h)	million €	9	11
CO_2 supply	million €	277	320
Synthesis, further processing	million €	186	218
Total	million €	736	730
	$€/kW_{PTL}$	3732	3076
Maintenance & repair			
Electrolysis	million €/yr	4.4	3.1
H_2 compression & storage	million €/yr	0.2	0.2
CO_2 supply	million €/yr	6.9	8.0
Synthesis, further processing	million €/yr	3.7	4.4
Total	million €/yr	15.3	15.6
	% of CAPEX/yr	2.1%	2.1%
Specific cost data			
Cost of fuel supply including transport and distribution	$€/GJ_{PTL}$	73	60
	$€/kWh_{PTL}$	0.263	0.215
	$€/l_{Diesel\ eq}$	2.63	2.14

The costs for the supply of Fischer-Tropsch diesel via power-to-liquid using nuclear electricity amount to 2.63 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 2.14 € per l of diesel equivalent.

3.2.6 Diesel via power-to-liquid from 100 % wind and solar (renewable)

Electricity is generated in a newly built wind and photovoltaic power stations in France and transported to a power-to-liquid plant which consists of low temperature water electrolysis, H_2 buffer storage, a direct air capture of CO_2 (DAC), CO_2 liquefaction, CO_2 buffer storage, H_2 and CO_2 compressors, Fischer-Tropsch syntheses, and upgrading of the liquid hydrocarbons to gasoline, kerosene and diesel. The diesel is transported to a depot via train, pipeline, and ship. From there, the diesel is transported to the refueling stations where it is dispensed to the trucks.

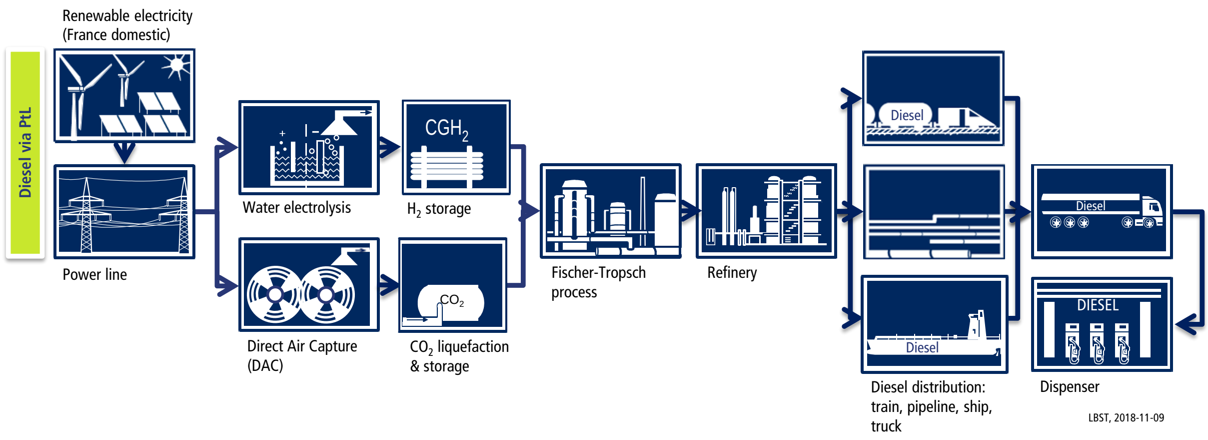


Figure 29: Pathway diagram of PtL Diesel supply from renewable electricity

The specific investment for photovoltaic (PV) and wind power plants has decreased significantly in the last ten years. Figure 30 shows the development of the PV panel prices since February 2010 based on data in [IRENA 2018] (exchange rate: 0.9039 €/US$).

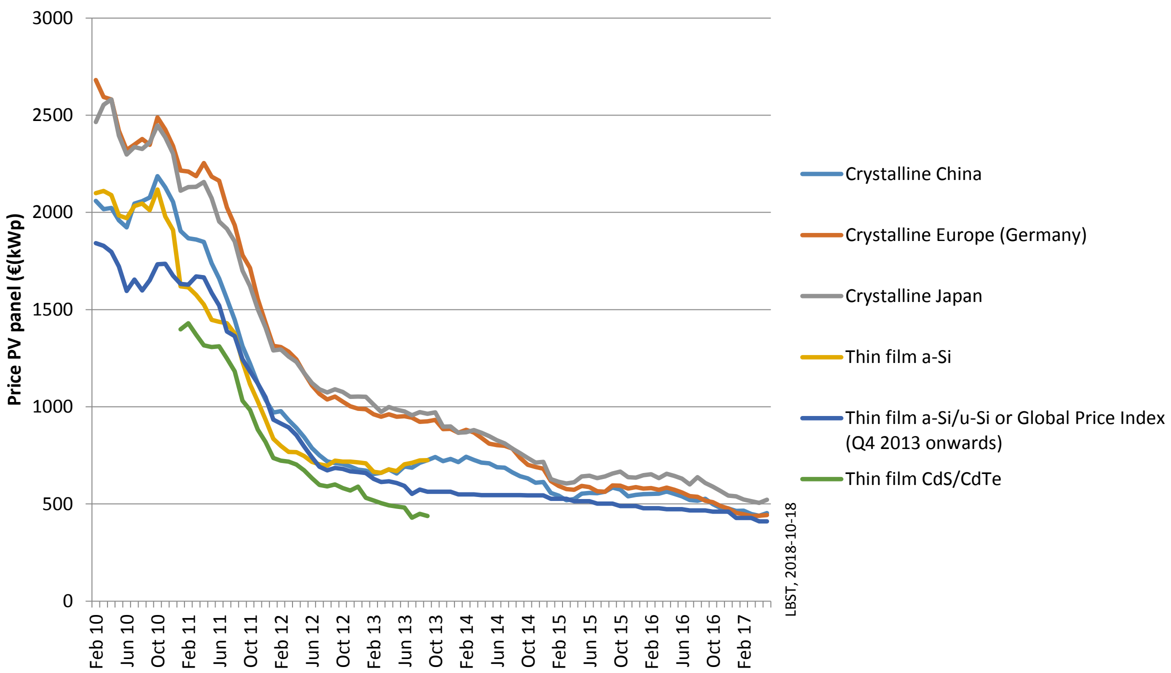


Figure 30: Development of PV panel prices

Various large-scale PV power stations have been built or are under construction in the EU. Table 26 show the Technical and economic data of selected PV power plants in the EU.

Table 26: Technical and economic data of selected PV power plants in the EU (existing and under construction)

Parameter	Unit	Cestas Solar Park (Bordeaux, France)	Don-Rodrigo (Sevilla, Spain)	Mula (Murcia, Spain)	Ourique (Portugal)	This study 2020
Capacity	MWp	300	174	500	46	
Electricity generation	GWh/yr	350	300	750	80	
	kWh/kW_p	1167	1724	1500	1739	1340
CAPEX	million €	360	100	450	40	
	$€/kW_p$	1200	575	900	870	750
Commissioning date		2015	2019	2019	2018	2020

PV and wind are complementary. During periods of high wind speeds the yield of PV is lower and vice versa. The electricity for the power-to-liquid plant is supplied by a hybrid PV/wind power plant consisting of 50/50 mix of PV and wind (related to the rated power). Analogous to [Fasihi et al. 2016] an overlap of 5% has been assumed.

The CAPEX for wind power in 2020 has been derived from [Deutsche WindGuard 2015] for wind converters with a hub height of 120 to 140 m. The equivalent full load period of such a plant is indicated with 2688 h per year for a typical location in Germany (80% of standard yield). According to [JRC 2018] the electricity yield for wind power installed in France is at about 25% higher than in Germany leading to an equivalent full load period of about 3360 h per year.

For 2030 a further cost reduction du to series production has been assumed based on learning curves. Analogous to [ISE 2018] for photovoltaic a progress ratio (PR) of 0.85 and for wind power a progress ration of 0.95 has been assumed. Table 27 shows the world-wide cumulative installed capacities of photovoltaic and wind power which has been assumed for the calculation of the CAPEX in 2030.

Table 27: Cumulative world-wide installed capacity of renewable power

	2018 (GW)	2020 (GW)	2030 (GW)	Reference
Photovoltaic (PV)	507	762	3212	[ISE 2018]*
Wind power onshore	599	801	1934	[GWEC 2014]**

* ISE Medium-Scenario; ** Advanced scenario

Table 28 and Table 29 show the technical and economic data for electricity generation form a hybrid PV/wind power plant in 2020 and 2030 respectively.

Table 28: PV/wind hybrid in France in 2020

	Unit	Photovoltaic (PV)	Wind	Hybrid PV/wind
Rated power	MW	100	100	-
Lifetime	yr	25	25	-
Equivalent full load period	h/yr	1340	3360	4,465
Electricity generation	kWh/yr	134,000,000	336,000,000	446,500,000
Investment	€/kW	750	1567	
	€	75,000,000	156,700,000	231,700,000
Costs of capital	€/yr	4,800,897	10,030,675	14,831,572
O&M	€/(kW*yr)	10	56	-
	€/yr	1,000,000	5,600,000	6,600,000
Total	€/yr	5,800,897	15,630,675	21,431,572
	€/kWh	0.043	0.047	0.048

Table 29: PV/wind hybrid in France in 2030

	Unit	Photovoltaic (PV)	Wind	Hybrid PV/wind
Rated power	MW	100	100	-
Lifetime	yr	25	25	-
Equivalent full load period	h/yr	1340	3360	4,465
Electricity generation	kWh/yr	134,000,000	336,000,000	446,500,000
Investment	€/kW	486	1437	
	€	48,637,826	143,683,629	192,321,455
Costs of capital	€/yr	3,113,403	9,197,471	12,310,874
O&M	€/(kW*yr)	10	56	-
	€/yr	1,000,000	5,600,000	6,600,000
Total	€/yr	4,113,403	14,797,471	18,910,874
	€/kWh	0.031	0.044	0.042

The electricity is transported via the electricity grid to the power-to-liquid plant. Table 30 shows the costs for electricity transport via the high voltage electricity grid based on data in [RTE 2018b]. The difference compared to the transport of nuclear electricity is the lower equivalent full load period.

Table 30: **Costs of electricity transport and distribution using domestic renewable electricity (>4000 h/yr; 130 kV < x < 350 kV)**

Costs of electricity transport and distribution for large-scale PtX plant using domestic renewable electricity (>4000 h/yr; 130 kV < x <							500 MW	
		Peak hours	**High season peak hours**	**High season off-peak**	**Low season peak hours**	**Low season off-peak**		
Demand rate		PS1	PS2	PS3	PS4	PS5	Total/installed	
bi	€/(kW*yr)	12.13	11.65	9.68	7.54	3.73		RTE 2018, p. 29
Power demand	kW	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	
	€/yr	12,130,000					12,130,000	
	€/kWh						0.003	
Energy rate		E1	E2	E3	E4	E5	Total	
ci	cent/kWh	0.83	0.61	0.43	0	0		RTE 2018, p. 29
Duration time ranges PS1 to PS5	h/yr	131	749	968	1247	1371	4465	
Electricity demand	kWh	131,066,536	748,535,551	967,562,296	1,246,588,389	1,371,247,228	4,465,000,000	
	€/yr	1,087,852	4,566,067	4,160,518	0	0	9,814,437	
	€/kWh						0.002	
Costs of electricity transport total	€/kWh						**0.009**	

The same power-to-liquid plant as for nuclear electricity (chapter 3.2.5) has been used for renewable electricity as input except the capacity of the hydrogen storage and the different equivalent full load period. In case of renewable electricity it has been assumed that the H_2 storage capacity is sufficient for 50 hours (more than two days) of full load operation. Table 31 shows the fact sheet for the supply of synthetic diesel via power-to-liquid from renewable electricity in France.

Table 31: Fact sheet: power-to-Liquid plant using renewable electricity in France and costs of the supply of final fuel

	Unit	2020	2030
Technical key data			
Electricity input	MW_e	598	580
Fuel output	MW_{PtL}	197	237
Specific electricity input	MJ/MJ_{PTL}	3.03	2.44
Efficiency PtL plant		33%	41%
CO_2 demand (gross)	t/h	67.2	80.9
Equivalent full load period	h/yr	4465	4465
CAPEX			
Electrolysis	million €	264	181
H_2 compression & storage (50 h)	million €	138	166
CO_2 supply	million €	277	320
Synthesis, further processing	million €	186	218
Total	million €	865	885
	$€/kW_{PTL}$	4387	3731
Maintenance & repair			
Electrolysis	million €/yr	4.4	3.1
H_2 compression & storage	million €/yr	0.2	0.2
CO_2 supply	million €/yr	6.9	8.0
Synthesis, further processing	million €/yr	3.7	4.4
Total	million €/yr	15.3	15.6
	% of CAPEX/yr	1.8%	1.8%
Specific cost data			
Cost of fuel supply including transport and distribution	$€/GJ_{PTL}$	71	54
	$€/kWh_{PTL}$	0.254	0.196
	$€/l_{Diesel\ eq}$	2.53	1.95

The costs for the supply of Fischer-Tropsch diesel via power-to-liquid using domestic renewable electricity in France amount to 2.53 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.95 € per l of diesel equivalent.

3.2.7 Diesel import via power-to-liquid from 100 % wind and solar in MENA region (renewable)

The electricity is generated via a mix of PV and wind power in the MENA region (e.g. North Africa) and transported via a HVDC transmission line over a relatively short distance of about 200 km to the power-to-liquid plant which is also located in North Africa.

The final products are transported via ship to a port in France over a distance of about 3400 km. From the port, the diesel is transported to a depot via train, pipeline, and ship. From there, the diesel is transported to the refueling stations where it is dispensed to the trucks.

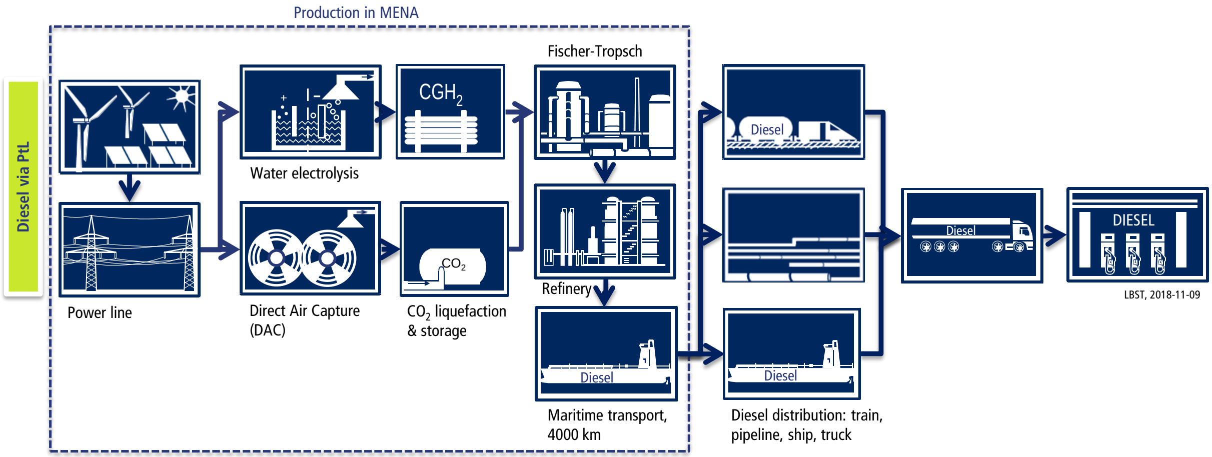


Figure 31: Pathway diagram of PtL Diesel import from renewable electricity in MENA region

Analogous to [Fasihi et al. 2016] a 50/50 mix of PV and wind power leading to an equivalent full load period of the power-to-liquid plant of 6840 hours per year (Table 32). An overlap of 5% has been assumed.

Table 32 and Table 33 show the technical and economic data for electricity generation in North Africa.

Table 32: PV/wind hybrid power plant in North Africa in 2020

	Unit	Photovoltaic (PV)	Wind	Hybrid PV/wind
Rated power	MW	5000	5000	-
Lifetime	yr	25	25	-
Equivalent full load period	h/yr	2000	5200	6,840
Electricity generation	kWh/yr	10,000,000,000	26,000,000,000	34,200,000,000
Investment	€/kW	750	1567	
	€	3,750,000,000	7,835,000,000	11,585,000,000
Costs of capital	€/yr	240,044,860	501,533,728	741,578,589
O&M	€/(kW*yr)	8	56	
	€/yr	40,000,000	280,000,000	320,000,000
Total	€/yr	280,044,860	781,533,728	1,061,578,589
	€/kWh	0.028	0.030	0.031

Table 33: PV/wind hybrid power plant in North Africa in 2030

	Unit	Photovoltaic (PV)	Wind	Hybrid PV/wind
Rated power	MW	5000	5000	-
Lifetime	yr	25	25	-
Equivalent full load period	h/yr	2000	5200	6,840
Electricity generation	kWh/yr	10,000,000,000	26,000,000,000	34,200,000,000
Investment	€/kW	486	1437	
	€	2,431,891,298	7,184,181,444	9,616,072,742
Costs of capital	€/yr	155,670,135	459,873,555	615,543,691
O&M	€/(kW*yr)	8	56	
	€/yr	40,000,000	280,000,000	320,000,000
Total	€/yr	195,670,135	739,873,555	935,543,691
	€/kWh	0.020	0.028	0.027

Table 34 shows the technical and economic data for electricity transmission to the power-to-liquid plants.

Table 34: HVDC transmission to power-to-liquid plant

Parameter	Value	Reference
Capacity	5000 MW	[Fasihi et al. 2016]
Distance	200 km	Assumption
Investment transmission line	0.612 €/(km*kW)	[Fasihi et al. 2016]
	612 million €	
Lifetime	50 yr	[Fasihi et al. 2016]
Maintenance & repair	1.2 of investment/yr	[Fasihi et al. 2016]
Investment converters	180 €/kW (360 €/kW for both sides)	[Fasihi et al. 2016]
	1800 million €	
Lifetime converters	50 yr	
Maintenance & repair	1.0 of investment/yr	[Fasihi et al. 2016]
Costs of electricity transport	0.004 €/kWh	

As a result the costs of electricity at the gate of the power-to-liquid plant amounts to about 3.5 cent/kWh in 2020 and about 3.1 cent/kWh in 2030.

The same power-to-liquid plant as for domestic electricity in France (chapter 3.2.6) has been used for the power-to-liquid plant in the Middle East and North Africa (MENA) region except the different equivalent full load period.

The final products (gasoline, kerosene, and diesel) are transported to France over a distance of about 3400 km (one way) via a heavy fuel oil fueled product tanker with a transport capacity of 50,000 t.

Table 35 shows the fact sheet for the supply of synthetic diesel via power-to-liquid from renewable electricity in the MENA region.

Table 35: Fact sheet: power-to-Liquid plant using renewable electricity in the MENA region and costs of the supply of final fuel

	Unit	2020	2030
Technical key data			
Electricity input	MW_e	598	580
Fuel output	MW_{PtL}	197	237
Specific electricity input	MJ/MJ_{PTL}	3.03	2.44
Efficiency PtL plant		33%	41%
CO_2 demand (gross)	t/h	67.2	80.9
Equivalent full load period	h/yr	6840	6840
CAPEX			
Electrolysis	million €	264	181
H_2 compression & storage (50 h)	million €	138	166
CO_2 supply	million €	277	320
Synthesis, further processing	million €	186	218
Total	million €	865	885
	$€/kW_{PTL}$	4387	3731
Maintenance & repair			
Electrolysis	million €/yr	4.4	3.1
H_2 compression & storage	million €/yr	0.2	0.2
CO_2 supply	million €/yr	6.9	8.0
Synthesis, further processing	million €/yr	3.7	4.4
Total	million €/yr	15.3	15.6
	% of CAPEX/yr	1.8%	1.8%
Specific cost data			
Cost of fuel supply including transport and distribution	$€/GJ_{PTL}$	47	36
	$€/kWh_{PTL}$	0.168	0.131
	$€/l_{Diesel\ eq}$	1.67	1.30

The costs for the supply of Fischer-Tropsch diesel via power-to-liquid using renewable electricity in the MENA region amount to 1.67 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.30 € per l of diesel equivalent.

3.2.8 Methane via power-to-methane from 100 % wind and solar (renewable)

Electricity is generated in a newly built wind and photovoltaic power stations in France and transported to a power-to-methane plant which consists of low temperature water electrolysis, H_2 buffer storage, direct air capture of CO_2 (DAC), CO_2 liquefaction, CO_2 buffer storage, H_2 compressors, and the methanation step. The methane is transported and distributed via the natural gas grid to the refueling stations where it is compressed or liquefied and dispensed as CNG or LNG.

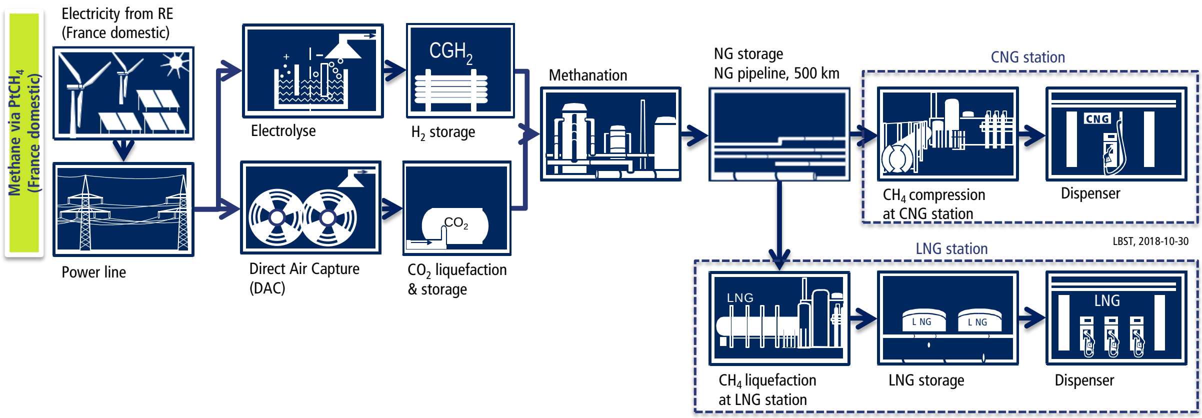


Figure 32: Pathway diagram of $PtCH_4$ supply from renewable electricity

For the electricity supply the same assumptions as for synthetic diesel via power-to-liquid using domestic renewable electricity in France (chapter 3.2.8) have been applied.

The capacity of the electrolysis plant has been assumed to be the same as for the power-to-liquid plants (500 MW_e).

According to [Liese 2013] the CAPEC for a methanation plant with a capacity of 150,000 Nm^3 of CH_4 per hour (~1500 MW_{CH4}) ranges between 100 and 180 million €. The CAPEX include piping, instrumentation, engineering, labor costs, insurance, and freight. In this study the upper value for the CAPEX (180 million €) has been selected which has been adapted to the required capacity (245 in 2020 and 295 MW_{CH4} in 2030) via downscaling using a scaling exponent of 0.7 leading to a CAPEX of 51 million € for 2020 and 58 million € for 2030. The flexibility of methanation plants is better than that of Fischer-Tropsch plants. Therefore, the capacity of the hydrogen storage can be lower. The hydrogen storage capacity amounts to about two hours of full load operation.

The CH_4 liquefaction plant is located onsite the refueling station as in case of LNG from natural gas (chapter 3.2.2). The same refueling stations as in case of CNG and LNG from natural gas have been used.

Table 36 shows the fact sheet for the supply of methane as CNG and LNG via power-to-methane from domestic renewable electricity in France.

Table 36: Fact sheet: power-to-methane plant using renewable electricity in France and costs of the supply of final fuel

	Unit	2020	2030
Technical key data			
Electricity input	MW_e	562	536
Fuel output	MW_{CH4}	245	295
Specific electricity input	MJ/MJ_{CH4}	2.29	1.82
Efficiency $PtCH_4$ plant		44%	55%
CO_2 demand (gross)	t/h	48.4	58.2
Equivalent full load period	h/yr	4465	4465
CAPEX			
Electrolysis	million €	264	181
H_2 compression & storage (50 h)	million €	11	13
CO_2 supply	million €	215	248
Methanation	million €	51	58
Total	million €	540	500
	€/kW_{CH4}	2204	1696
Maintenance & repair			
Electrolysis	million €/yr	2.2	1.5
H_2 compression & storage	million €/yr	0.1	0.1
CO_2 supply	million €/yr	2.7	3.1
Methanation	million €/yr	0.5	0.6
Total	million €/yr	5.5	5.3
	% of CAPEX/yr	1.0%	1.1%
Specific cost data for CH_4 as CNG			
Cost of fuel supply including transport and distribution	€/GJ_{CH4}	51	38
	€/kWh_{CH4}	0.184	0.138
	€/$l_{Diesel\ eq}$	1.84	1.37
Specific cost data for CH_4 as LNG			
Cost of fuel supply including transport and distribution	€/GJ_{CH4}	55	42
	€/kWh_{CH4}	0.199	0.152
	€/$l_{Diesel\ eq}$	1.98	1.52

The costs for the supply of synthetic methane as CNG via power-to-methane using domestic renewable electricity in France amount to 1.84 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.37 € per l of diesel equivalent.

The costs for the supply of synthetic methane as LNG via power-to-methane using domestic renewable electricity in France amount to 1.98 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.52 € per l of diesel equivalent.

3.2.9 Methane import via power-to-methane from 100 % wind and solar in MENA region (renewable)

The electricity is generated via a mix of PV and wind power in the MENA region (e.g. North Africa) and transported via a HVDC transmission line over a relatively short distance of about 200 km to the power-to-methane plant which is also located in North Africa. The methane is transported via pipeline to France and subsequently distributed via the natural gas pipeline grid to the refueling stations where it is compressed or liquefied and dispensed as CNG or LNG.

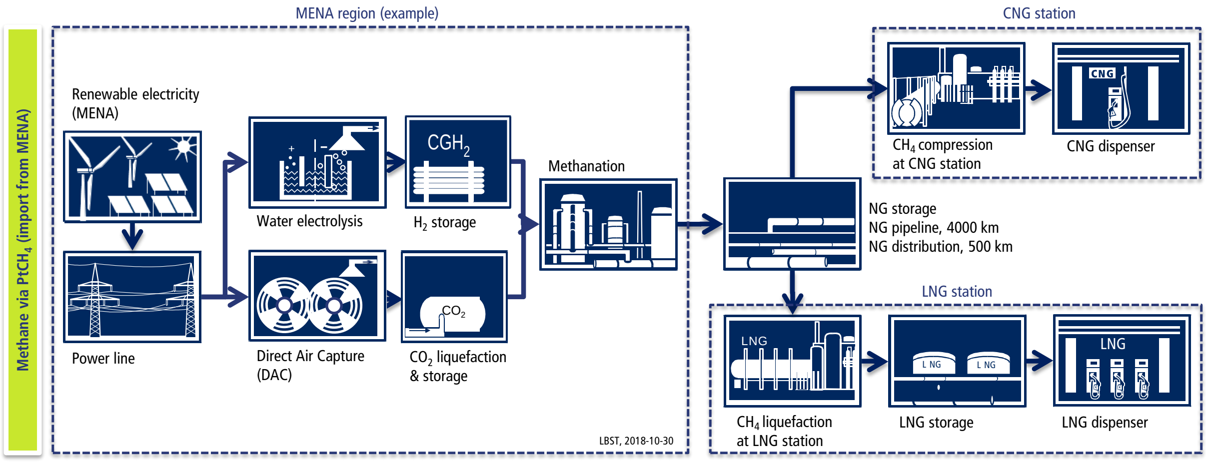


Figure 33: Pathway diagram of $PtCH_4$ import from renewable electricity in MENA region

For the electricity supply the same assumptions as for synthetic diesel via power-to-liquid using renewable electricity in the MENA region (chapter 3.2.9) have been applied. The capacity of the electrolysis plant has been assumed to be the same as for the power-to-liquid plants (500 MW_e). The same methanation plant as for domestic power-to-methane plants in France has been used.

Table 37 shows the technical and economic data for long-distance transport of methane via pipeline.

The amount of CH_4 delivered to France per year has been derived from the Maghreb–Europe Gas Pipeline. The capacity is indicated with 12 billion Nm^3 of gas per year or about 1,370,000 Nm^3/h. Multiplication with the equivalent full load period of the power-to-methane plant (6840 h/yr) leads to about 9.37 billion Nm^3 of methane per year or about 93.2 TWh of methane per year.

The mechanical requirement for the compressors is supplied by gas turbines. The methane gas requirement amounts to about 2 kWh per 1000 kWh of methane per compressor station [DGMK 1992]. Every 200 km a compressor station is installed. As a result the efficiency for methane transport can be calculated by

$$\left(\frac{1000-2}{1000}\right)^{12} = 97.6\%$$

This means that 97.6% of the methane injected into the pipeline in the MENA region can be supplied to consumers in France.

According to [Krieg 2012] the CAPEX of large compressors amounts to about 22 € per kW of hydrogen leading to 66 € per Nm³ and hour. Division by the lower heating of methane (9.95 kWh/Nm³) leads to about 6.63 € per kW of methane or about 9.04 million per compressor unit with a capacity of 13630 MW_{CH4}. There are 12 compressor units leading to about 1.08 billion €.

Table 37: Technical and economic data long distance CH_4 transport via pipeline

Parameter	Value	Reference/ comment
Length	2400 km	
Diameter	48 inch (1219 mm)	Maghreb–Europe Gas Pipeline
Equivalent full load period	6840 h/yr	
CH_4 delivered to France	93.2 TWh/yr	Maghreb–Europe Gas Pipeline
CAPEX pipeline	1239 €/m	[Bohlen & Doyen 2001]
	2.97 billion €	
Lifetime pipeline	50 yr	
Number of compressors	12	
Efficiency CH_4 transport	97.6%	[DGMK 1992]
Capacity compressor unit	13630 MW_{CH4}	
CAPEX compressors	1.08 billion €	[Krieg 2012]
Lifetime compressors	15 yr	[Santos 2004]
Maintenance & repair compressors	5% of $CAPEX_{compressors}$/yr	[Santos 2004]
Costs of CH_4 transport total	0.3 cent/kWh	

The CH_4 liquefaction plant is located onsite the refueling station as in case of LNG from natural gas (chapter 3.2.2). The same refueling stations as in case of CNG and LNG from natural gas have been used.

Table 38 shows the fact sheet for the supply of methane as CNG and LNG via power-to-methane from renewable electricity in the MENA region.

Table 38: Fact sheet: power-to-methane plant using renewable electricity in the MENA region and costs of the supply of final fuel

	Unit	2020	2030
Technical key data			
Electricity input	MW_e	562	536
Fuel output	MW_{CH4}	245	295
Specific electricity input	MJ/MJ_{CH4}	2.29	1.82
Efficiency $PtCH_4$ plant		44%	55%
CO_2 demand (gross)	t/h	48.4	58.2
Equivalent full load period	h/yr	6840	6840
CAPEX			
Electrolysis	million €	264	181
H_2 compression & storage (50 h)	million €	11	13
CO_2 supply	million €	215	248
Methanation	million €	51	58
Total	million €	540	500
	$€/kW_{CH4}$	2204	1696
Maintenance & repair			
Electrolysis	million €/yr	2.2	1.5
H_2 compression & storage	million €/yr	0.1	0.1
CO_2 supply	million €/yr	2.7	3.1
Methanation	million €/yr	0.5	0.6
Total	million €/yr	5.5	5.3
	% of CAPEX/yr	1.0%	1.1%
Specific cost data for CH_4 as CNG			
Cost of fuel supply including transport and distribution	$€/GJ_{CH4}$	37	28
	$€/kWh_{CH4}$	0.133	0.102
	$€/l_{Diesel\ eq}$	1.33	1.01
Specific cost data for CH_4 as LNG			
Cost of fuel supply including transport and distribution	$€/GJ_{CH4}$	41	32
	$€/kWh_{CH4}$	0.148	0.116
	$€/l_{Diesel\ eq}$	1.47	1.16

The costs for the supply of synthetic methane as CNG via power-to-methane using domestic renewable electricity in the MENA region amount to 1.33 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.01 € per l of diesel equivalent.

The costs for the supply of synthetic methane as LNG via power-to-methane using domestic renewable electricity in the MENA region amount to 1.47 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.16 € per l of diesel equivalent.

3.2.10 Hydrogen via power-to-hydrogen from 100 % wind and solar (renewable)

Electricity is generated in a newly built wind and photovoltaic power stations in France and transported via the electricity grid to hydrogen refueling stations with onsite hydrogen generation via water electrolysis. At the refueling station hydrogen is generated, stored, compressed, and dispensed to fuel cell electric vehicles.

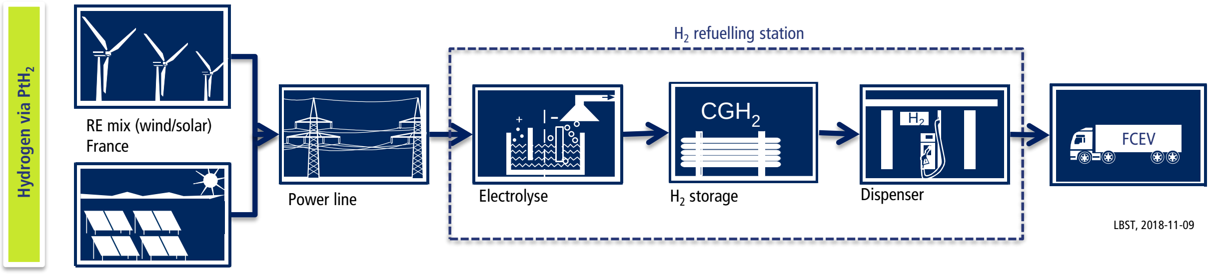


Figure 34: Pathway diagram of PtH_2 supply from renewable electricity

The electricity is generated by hybrid PV/wind power plant located in France (see chapter 3.2.6).

The refueling station with onsite hydrogen generation is connected to the medium voltage grid. The efficiency for transport and distribution of electricity via the high voltage (HV) and medium voltage (MV) level amounts to about 93.2% which leads to costs of about 5.2 cent per kWh of electricity at plant gate for electricity generation in 2020. For 2030 the costs for electricity generation at plant gate decreases to about 4.5 cent/kWh.

From the data in [RTE 2018b] (Tarif d'Utilisation des Réseaux Publics d'Électricité – TURPE) costs for electricity transport and distribution of 2.0 cent/kWh can be calculated for consumers connected to the medium voltage grid (see chapter 3.2.4).

For the electrolysis the 5 MW_e class has been selected to calculate the CAPEX for the different time horizons. Table 39 shows the technical and economic data for the electrolysis plant installed onsite the refueling station.

Table 39: Technical and economic data H_2 production via water electrolysis onsite the refuelling station

	Unit	2020	2030
Capacity	MW_e	4.61	3.83
	MW_{H2}	2.72	2.72
Electricity consumption	kWh/Nm^3	5.08	4.22
	kWh/kg	56	47
	kWh/kWh_{LHV}	1.693	1.407
Efficiency LHV	-	59.1%	71.1%
Efficiency HHV	-	69.8%	84.0%
CAPEX	million €	4.14	2.36
Maintenance & repair	€/yr	98,.927	56,453

The layout of the refueling station is similar to that used for hydrogen from natural gas (chapter 3.2.3) except the stationary hydrogen storage whose capacity is 200% of the average daily hydrogen demand (Table 40).

Table 40: CGH_2 refuelling station for H_2 delivery via onsite electrolysis

	Unit	2014*	2020	2030
Fuel output	GWh/yr	12.2	12.2	12.2
	kg/d	1000	1000	1000
Number of dispensers	-	2	2	2
Electricity consumption	**kWh/kWh_{CGH2}**	**0.292**	**0.198**	**0.120**
H_2 compression	kWh/kWh_{CGH2}	0.102	0.108	0.108
Pre-cooling	kWh/kWh_{CGH2}	0.190	0.090	0.012
Investment	**€**	**7,130,000**	**5,050,000**	**3,830,000**
H_2 bulk storage (200% of daily demand)	€	2,727,000	1,528,000	1,211,000
H_2 high pressure buffer	€	711,000	674,000	534,000
H_2 compressors	€	781,000	703,000	445,000
Pre-cooling	€	188,000	178,000	141,000
H_2 dispenser	€	157,000	148,000	118,000
Installation	€	716,000	604,000	445,000
Site preparation	€	155,000	131,000	96,000
Engineering & design	€	310,000	262,000	193,000
Contingency	€	155,000	131,000	96,000
Approval	€	10,000	10,000	10,000
Maintenance, safety inspection				
Maintenance & repair	€/yr	15,627	14,062	8,900
Safety inspection storage vessels	€/yr	2,925	1,950	1,950
Dispenser calibration	€/yr	1,432	1,432	1,432

The costs for the supply of CGH_2 via power-to-hydrogen using domestic renewable electricity in France amount to 2.04 € per l of diesel equivalent if cost data for 2020 are applied. For time horizon 2030 these costs will decrease to about 1.47 € per l of diesel equivalent.

3.2.11 Electricity for catenary from 100 % wind and solar (renewable)

Electricity from a hybrid PV/wind hybrid power station is distributed via the high voltage and medium voltage to the substations along the motorway where the electricity is converted to direct current for the catenary system. Electricity storage systems based on lithium-ion batteries are installed to avoid peaks in the electricity grid. As a back-up for vehicle operation outside the catenary system and low state of charge (SOC) of the on-board battery chargers are installed at the home base of the trucks.

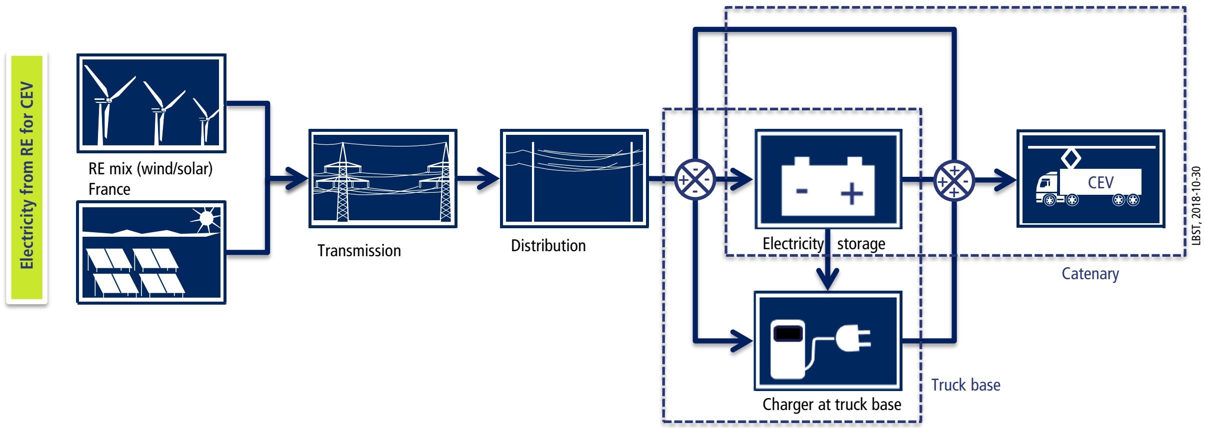


Figure 35: Pathway diagram of CEV electricity supply from renewable power

The electricity is generated by hybrid PV/wind power plant located in France (see chapter 3.2.6).

The substations along the motorway are connected to the medium voltage grid. The efficiency for transport and distribution of electricity via the high voltage (HV) and medium voltage (MV) level amounts to about 93.2% which leads to costs of about 5.2 cent per kWh of electricity at plant gate for electricity generation in 2020. For 2030 the costs for electricity generation at plant gate decreases to about 4.5 cent/kWh.

From the data in [RTE 2018b] (Tarif d'Utilisation des Réseaux Publics d'Électricité – TURPE) costs for electricity transport and distribution of 2.0 cent/kWh can be calculated for consumers connected to the medium voltage grid (see chapter 3.2.4).

The same catenary infrastructure as in case of the French electricity mix (chapter 3.2.4) has been assumed.

The integration of a catenary infrastructure on a highway may have to comply with several additional requirements, such as still allowing the landing of rescue helicopters (e.g. only multiple lane highways eligible), no temporarily released emergency lanes on motorways, double guardrails to protect catenary poles, etc.

3.3 Results well-to-tank

3.3.1 Environmental performance

The greenhouse gas emissions for the supply of final fuel include the supply of fossil and nuclear fuels (mining, extraction, transport e.g. to refinery or power stations) and the conversion to final fuel or electricity, and transport and distribution. They include CO_2 and non-CO_2 greenhouse gases such as CH_4 and N_2O.

Figure 36 and Figure 37 show the greenhouse gas emissions from the supply and use of various transportation fuels in 2020 and 2030 respectively.

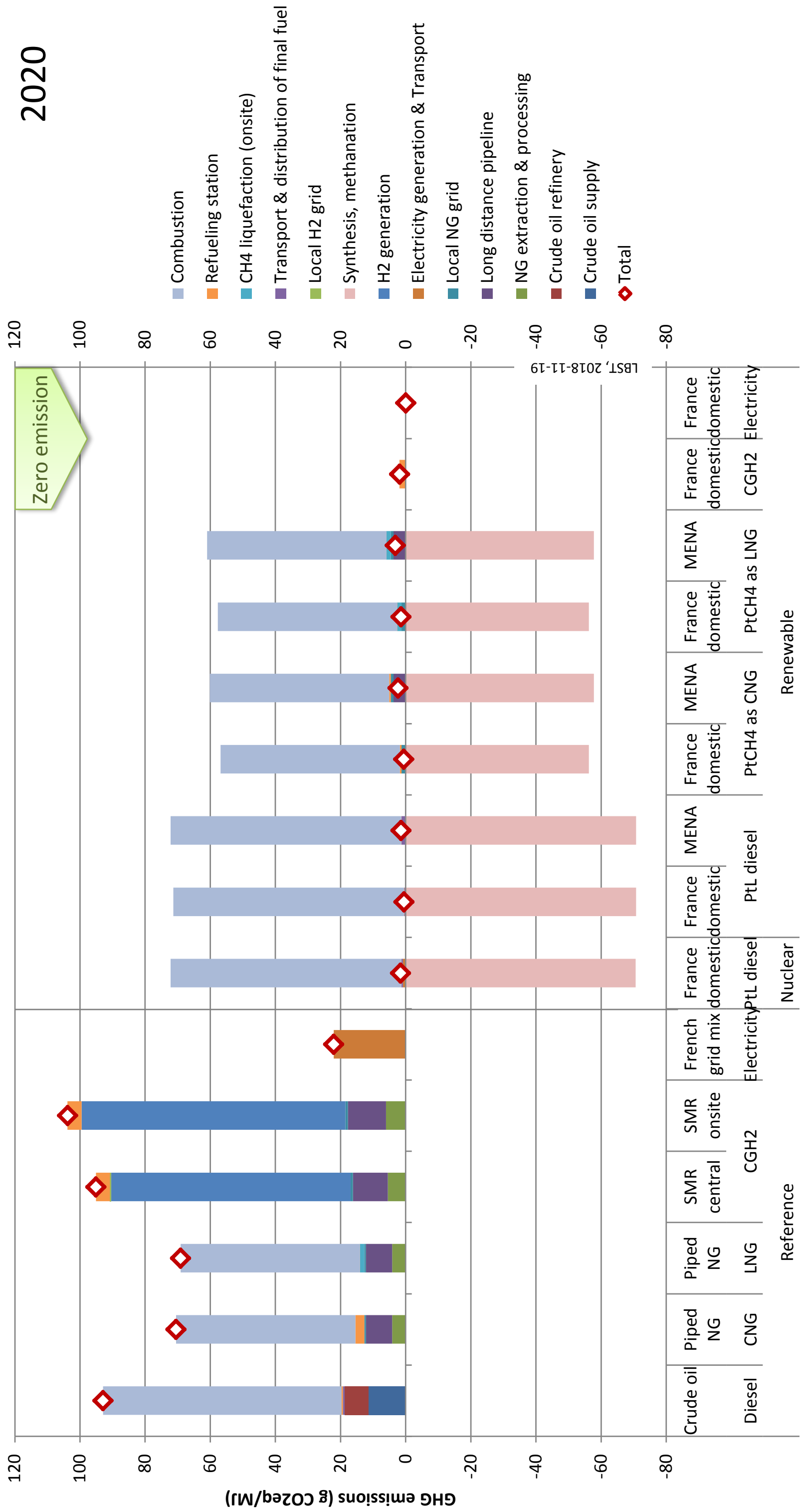


Figure 36: **Greenhouse gas emissions from the supply and use of various transportation fuels in 2020**

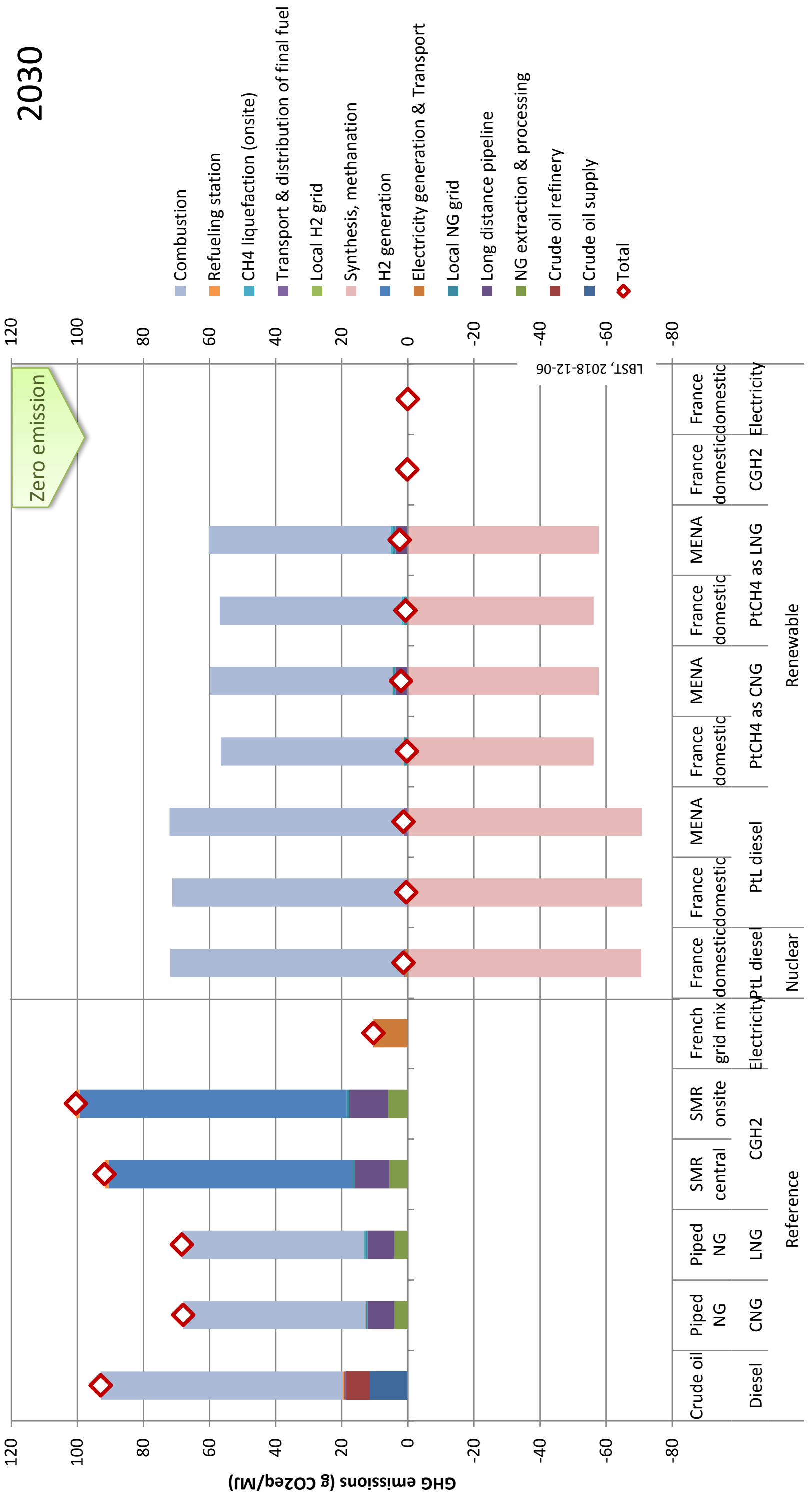


Figure 37: Greenhouse gas emissions from the supply and use of various transportation fuels in 2030

In case of carbon containing renewable transportation fuels the greenhouse gas emissions ‘well-to-tank’ are negative because CO_2 is absorbed from the atmosphere and bound in the final fuel. During combustion the CO_2 bound in the fuel is released leading to approximately zero net greenhouse gas emissions.

Since the share of coal power (which has high SO_2, NO_x and PM emissions depending on the flue gas treatment) in France is low for the pathways assessed in this study the emissions of air pollutants mainly occur during the final use in the vehicle (‘tank-to-wheel’).

The generation of electricity via nuclear power leads to radioactive waste. The amount of radioactive waste related to spent nuclear fuel ranges between 2.1 and 2.7 mg per kWh of electricity [BDEW 2018]. In Germany the upper value is used for electricity labelling. In this study the average value (2.4 mg/kWh of electricity) has been assumed.

The consumption of nuclear electricity for the supply of synthetic diesel via power-to-liquid leads to about 1.9 mg and 1.5 mg of **radioactive waste** per MJ of final fuel in 2020 and 2030 respectively (see Figure 59 and Figure 60 in Annex A1.1). The amount of radioactive waste decreases due the higher efficiency of the electrolysis plants and in case of electricity from the grid mix due to the lower share of nuclear electricity in 2030.

3.3.2 Energy use

Figure 38 and Figure 39 show the energy use for the supply of various transportation fuels in 2020 and 2030 respectively, split into fossil, nuclear and renewable energy.

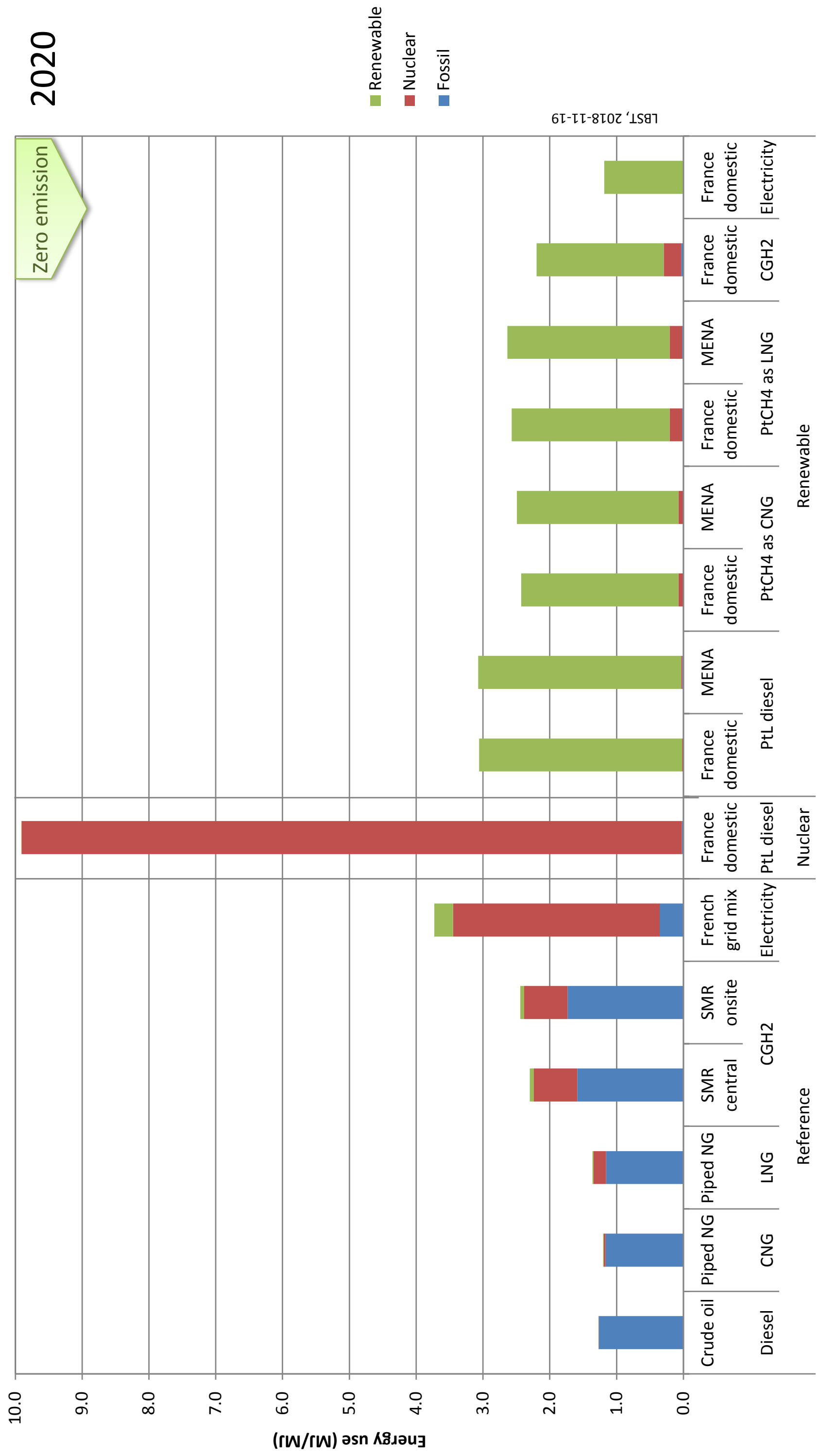


Figure 38: Energy use for the supply of transportation fuels 2020

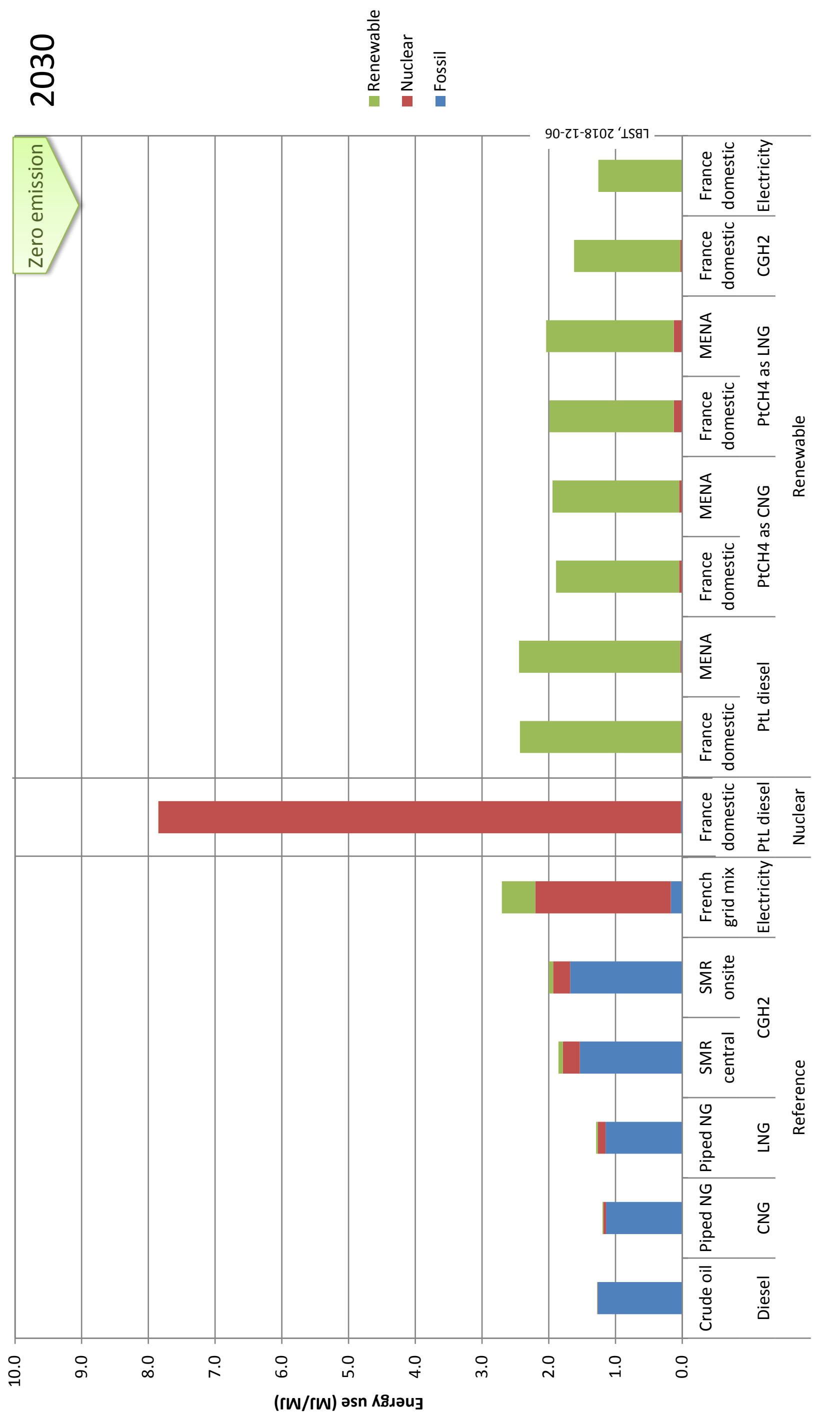


Figure 39: Energy use for the supply of transportation fuels 2030

The high energy use for electricity for catenary electric vehicles from nuclear power result from the efficiency of the nuclear power plant (37%). The energy use is based on the heat released by nuclear fission.

3.3.3 Costs of fuel supply

Figure 40 and Figure 41 show the cost of fuel supply in 2020 and 2030 respectively.

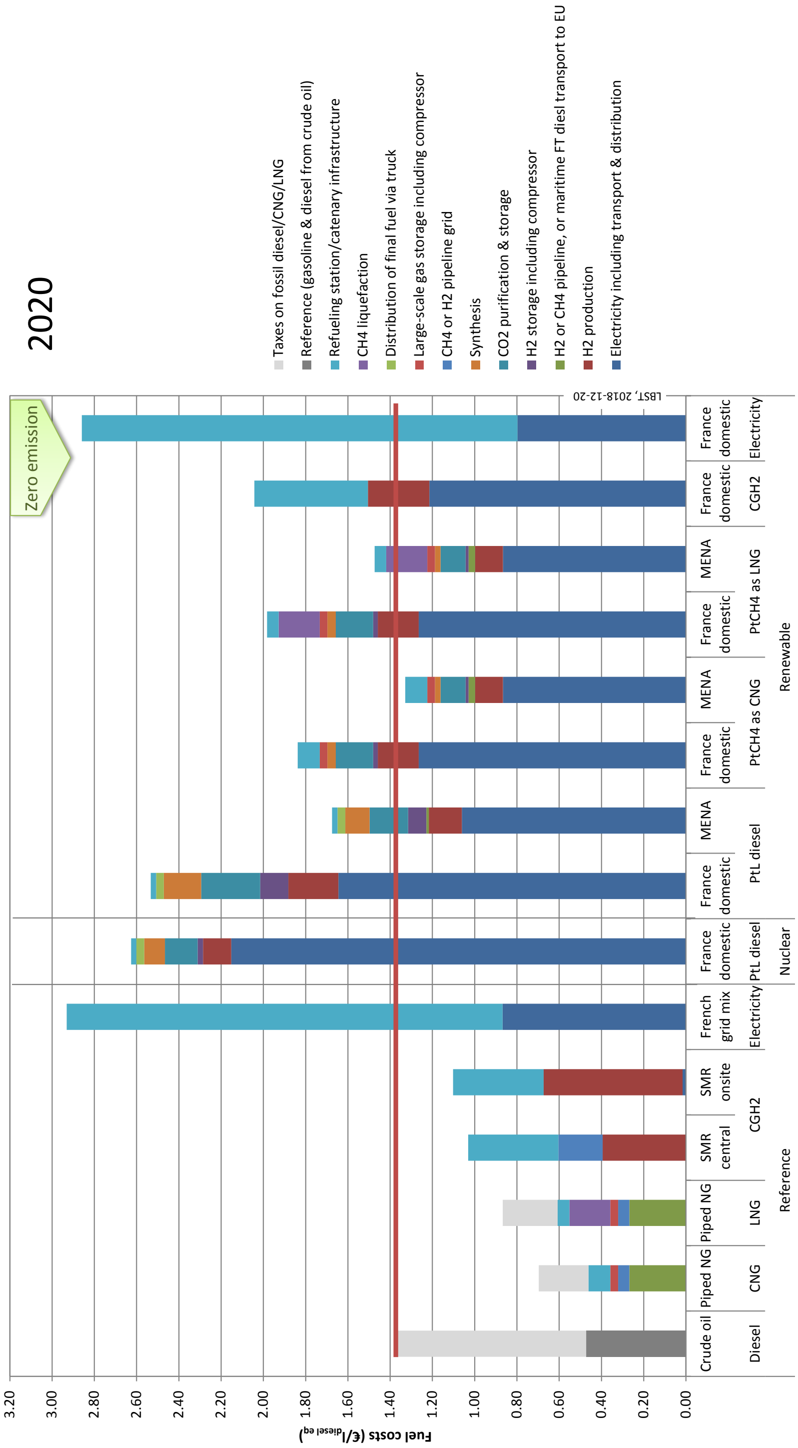


Figure 40: Costs of fuel supply in 2020

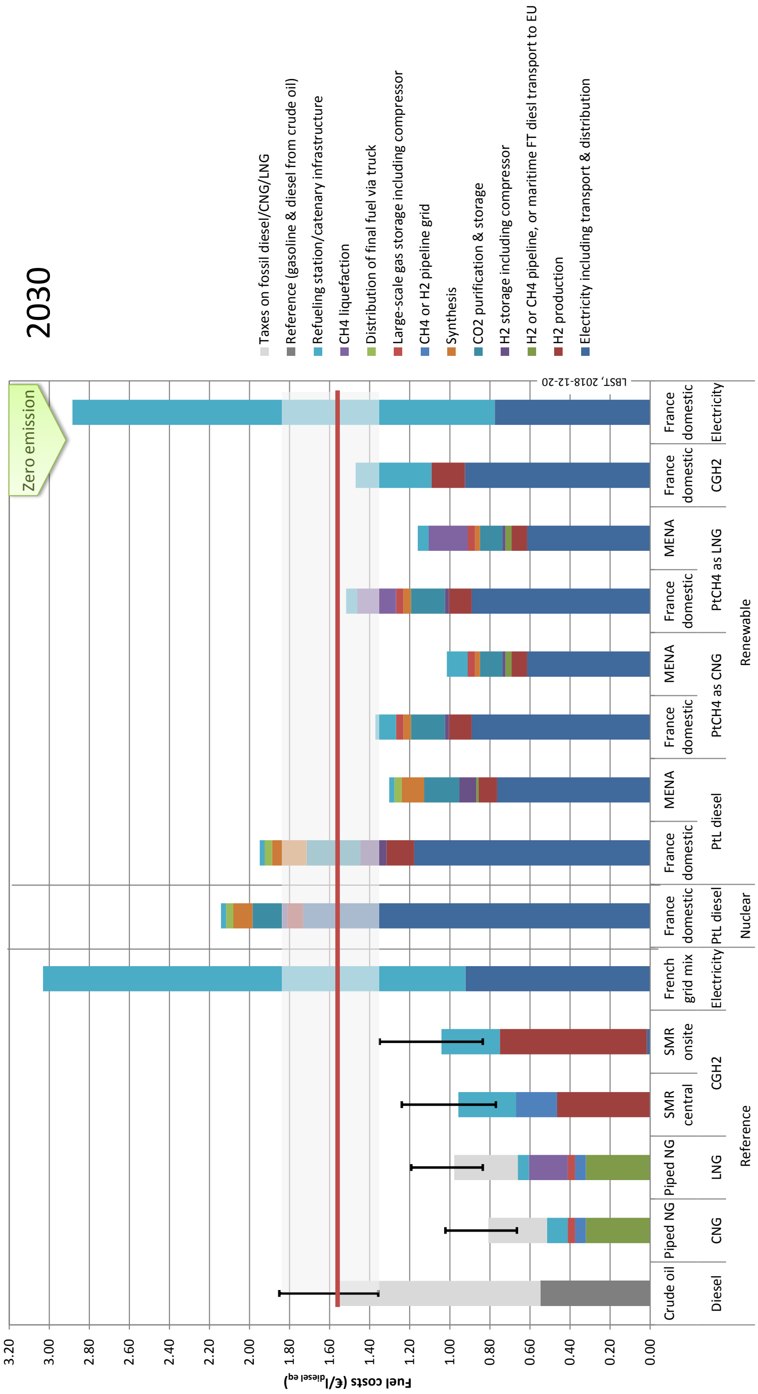


Figure 41: Costs of fuel supply in 2030

The costs of electricity for catenary electric vehicles (CEV) ‘tank-to-wheel’ are higher than that of other energy carriers. However, the high efficiency of electric vehicle leads to lower fuel costs per km (see chapter 5).

The reason for the high cost for synthetic diesel via power-to-liquid is the lower efficiency of the power-to-liquid plant using domestic nuclear or renewable electricity leading to high electricity consumption. In case of synthetic diesel via power-to-liquid from the MENA region the low efficiency of the power-to-liquid plant is compensated by the low electricity cost due to high solar irradiation and high wind speeds.

4 VEHICLE & DRIVETRAINS (TANK-TO-WHEEL)

As representative for a heavy duty truck a tractor truck for a tractor trailer combination with a maximum gross weight of 40 t has been used. The following drivetrains have been assessed:

- Diesel with internal combustion engine (ICE) based on Diesel cycle
- CNG ICE (Otto cycle)
- LNG ICE (Otto cycle)
- LNG ICE Diesel cycle using high pressure direct injection (HPDI)
- Fuel cell electric vehicle (FCEV)
- Catenary electric vehicle

4.1 Diesel ICE

Diesel fueled ICE is the common drivetrain for heavy duty vehicles today. Although today's diesel engines have a high efficiency (up to 44.8% peak brake thermal efficiency) some authors expect a further increase of the efficiency to 55.0% peak brake thermal efficiency e.g. via waste heat recovery. The fuel consumption of trucks can also be lowered via improving the aerodynamics and lowering the rolling resistance. Adding hybridization leads to a decrease of fuel consumption too. As a result the potential for reduction of fuel consumptions can reach 57% compared to today's tractor-trailer combinations [Meszler et al. 2018].

It hast to be noted that the reduction of aerodynamic drag cannot fully be transferred from diesel trucks to trucks with alternative drivetrains such as CEV (chapter 4.4) where the pantograph leads to an increase of aerodynamic drag.

Based on fuel consumption data in the lastauto omnibus katalog from 2010 to 2017 a reduction of fuel consumption hardly can be detected in the last years. Figure 42 shows the development of real world fuel consumption of tractor trucks in the last years based on a transport capacity utilization of 50% and 80% respectively. Furthermore, the impact of higher load utilization is low from an energy strategy point-of-view, albeit relevant with regards to total cost of ownership and the number of trucks needed to satisfy a given transport demand (tonne-km per year). The average fuel consumption in Figure 42 is derived from a more detailed assessment of the range of fuel consumptions of new diesel trucks. For this, see Figure 63 and Figure 64 in the Annex.

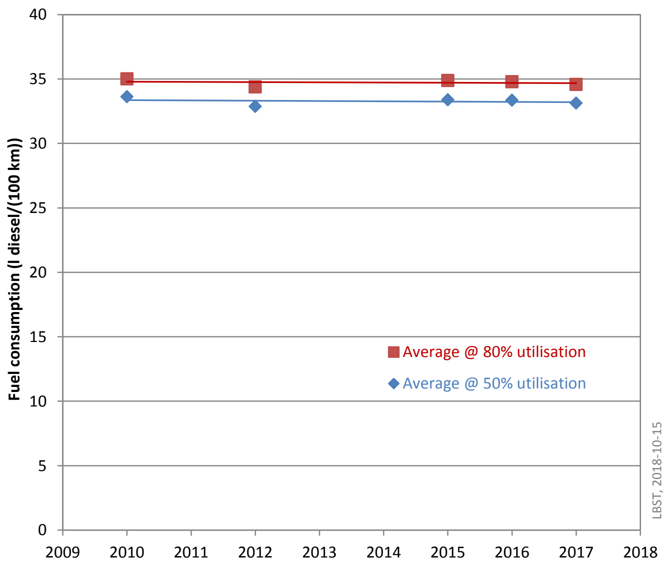


Figure 42: Development of real world fuel consumption of tractor trucks in the last years for a payload utilization of 50% and 80%

In this study also in case of diesel ICE the efficiency potential indicated in [Meszler et al. 2018] has not fully be exploited in 2030. For consistency the fuel consumption data for all drivetrains have been derived from [Moultak et al. 2017].

4.2 CNG and LNG ICE

CNG fueled buses wit gas engines based on the Otto cycle are operated in various cities in the world. Meanwhile, some companies offer CNG fueled trucks with gas engines (Iveco) and LNG fueled trucks with HPDI engines (Volvo). In case of HPDI it was a challenge for manufacturers to meet the Euro VI emissions limits for a long time. Now, Volvo has succeeded to develop a HPDI engine which meets the Euro VI emissions limits [Volvo 2017].

In case of HPDI the engine cannot be operated on methane only. Small amounts of diesel are required for ignition.

For the well-to-wheel analysis (chapter 5) we have assumed gas engines (Otto cycle) because there are established products for truck power train and no diesel for ignition is required. Furthermore, Otto engines have a lower noise signature than Diesel engines and exhaust gas treatment is less complex and thus more robust.

4.3 Fuel cell electric vehicle (FCEV)

Prototype fuel cell trucks with a maximum gross weight of 80,000 lb (~36 t) have been built in the USA [GNA 2012], [US Hybrid 2015], [US Hybrid 2017]. Within the framework of a pilot project in the port area of Los Angeles and Long Beach fuel cell trucks have been tested for the logistics within the port and logistics in greater Los Angeles. Reduction of air pollutants was the main intention of the project.

Initially a fuel cell truck from the meanwhile not existing manufacturer Vision Motors has been used. This fuel cell truck had a relatively small fuel cell power plant with an electricity output of 33 to 65 kW and a large battery with a capacity of 130 kW [ShowTimes 2011], [Vision Motors 2012].

In 2015, the company US hybrid published data for its 'H_2 truck' for the first time. An updated data sheet has been published in 2017. The rated power output of the fuel cell power plant amounts to 80 kW and the mechanical power of the electric motor amounts to 320 kW [US Hybrid 2015], [US hybrid 2017]. The 'H_2 truck' can be ordered with 35 MPa CGH_2 tanks with a hydrogen storage capacity of about 25 kg. The maximum range is indicated with 320 km [US Hybrid 2017]. The electricity storage capacity of the battery is sufficient to provide enough peak electricity output, so that the maximum electricity output of 80 kW of the fuel cell power plant is sufficient for certain driving cycles.

However, at a speed of 70 km/h about 56 kW of mechanical work is required to compensate the rolling resistance and about 42 kW of mechanical work is required to compensate the aerodynamic drag leading to a total mechanical work demand of 98 kW [ISI 2016]. As a result the 80 kW fuel cell power installed in the 'H_2 truck' is not sufficient for travelling a long distance with a speed of 70 km/h.

In 2017 Toyota introduced a fuel cell truck with maximum gross weight of 80,000 lb. The tractor truck is based on a Kenworth T660, with the sleeper cab area replaced with a big box that houses four high-pressure hydrogen tanks and two 6 kWh lithium-ion batteries (12 kWh total). Two fuel cell stacks from Toyota's Mirai fuel cell passenger vehicle (228 kW total) has been installed. The electric motor has a rated power of 670 hp (500 kW) and can deliver a torque of 1,325 lb-ft (1795 Nm) which is approximately the same as that of powerful diesel engines [Torchinsky 2017], Toyota 2017]. The hydrogen storage capacity of the pressure vessels amounts to 40 kg leading to a range of 150 miles (241 km) for a full load of 60,000 lbs (~27 t) or about 240 miles (386 km) for a 36,000 lb (~16 t) load [Torchinsky 2017]. As a result the energy related fuel consumption amounts to about 12.2 to 19.9 MJ per km (34.6 to 55.4 l diesel equivalent per 100 km). This has to be compared with an equivalent diesel truck (Kenworth 660 with diesel engine) which reaches 5 miles per gallon of diesel indicated in [Torchinsky 2017] leading to about 16.9 MJ/km (47.0 l diesel per 100 km), probably for part load.

In July 2018 Toyota introduced the 'Beta' version of its trucks with increasing the estimated range to more than 300 miles per fill [Toyota 7/2018]. Since it first began operation in April 2017, the 'Alpha' version of the truck has logged nearly 10,000 miles (~16,000 km) of testing and real-world drayage operations in and around the Ports of Long Beach and Los Angeles. In September 2018 a project in Los Angeles has been started where 10 Toyota fuel cell trucks will be in operation. The project is funded by the California Air Resources Board (CARB) [Toyota 2018].

Hyundai will deliver 1000 fuel cell trucks with a maximum gross weight of 18 t to Switzerland in collaboration with the Swiss company H_2 Energy. The range will be 400 km per fill [Hyundai 9/2018].

Esoro has developed a fuel cell truck with a maximum gross weight of 34 t in collaboration with Swiss Hydrogen based on a MAN TGS 18.320 4x2 [Coop 2016]. The net storage capacity of the 35 MPa vehicle tanks amounts to 31 kg providing 375 to 400 km per fill. The system efficiency of the fuel power plant is indicated with 52%. The rated power (continuous operation) of the fuel cell system is indicated with 100 kW. The fuel consumption ranges between 9.3 to 9.9 MJ per km (25.9 to 27.6 l diesel equivalent per 100 km). Although it is a rigid truck with trailer and not a tractor truck semi-trailer combination the technical requirements and fuel consumption data are similar.

In November 2018 the US American company Nikola announced to offer an EU version (Nikola Tre) of its fuel cell tractor truck beginning 2022 to 2023 (same timeframe as in the USA). European testing is projected to begin in Norway around 2020. The rated power of the electric motor will be 500 to 1000 hp (373 to 746 kW, that of the fuel system 120 kW. The range will be 500 to 1200 km per fill. 70 MPa vehicle tanks will be used for hydrogen storage [Nikola 2018]. In the USA the Brewer Anheuser-Bush announced to order 800 fuel cell trucks from Nikola [Anheuser-Bush 2018]. Some authors expect that Nikola is the Tesla of the trucks.

Table 41 shows a comparison of existing and announced FCEV compared to the assumption in this study.

Table 41: Comparison existing FCEV with assumptions in this study

	Unit	Esoro (Hyundai)	Nikola Two	Nikola Tre	Toyota (alpha)	This study 2020**
Region	-	CH	USA	EU	USA	EU
Maximum gross weight	t	34	36	40	36	40
Fuel cell system	kW_e	100	240	120	228 (stack)	350
Electric motor	kW_{mech}	250		373-746	500	400
Capacity H_2 tank	kg_{H2}	31 (net)	60-80		40	77
Pressure H_2 tank	MPa	35	70	70	70	70
Range	km	375-400	750-1200	500-1200	241-486*	1050
Fuel consumption	kg_{H2}/100 km	7.5-8.0	6.67-8.00		10.36-16.5*	7.33
	MJ_{LHV}/km	9.9	8.0-9.6		12.4-19.9*	8.8
	kWh_{LHV}/km	2.75	2.22-2.67		3.45-5.52	2.45
Production start	-	(2019)	2022-2023	2022-2023		2020

* Alpha version, depending on the transport capacity utilisation (16-27 t);
** Based on [Moultak et al. 2017]

The fuel consumption of heavy duty vehicles strongly depend on the driving cycle and the transport capacity utilization. For consistency reasons we use the same reference [Moultak et al. 2017] for all drivetrains.

4.4 Catenary electric vehicle (CEV)

Catenary electric vehicles (CEV) have been used in mining operations since decades in Zambia, Chile, and South Africa. The traction power ranges between 2000 and 6500 kW. Electric drivetrains are advantageous to internal combustion engines in terms of maintenance effort and costs in this power level. Manufacturers are Hitachi and Siemens [CE Delft & DLR 2013].

Recently CEV are discussed for long-haul trucks on motorways to provide zero emission transport.

In Sweden, Scania and Volvo in cooperation with Siemens are developing catenary trucks. A prototype catenary truck developed by Scania and already tested in Sweden in 2012 [CE Delft & DLR 2013]. The use of catenary trucks with a transport capacity of 90 t for the transport of iron ore concentrate from an iron ore mine in the North of Sweden to railway depots over a distance of 140 km has been investigated [Björkmann 2013].

Recently, a catenary system with a length of 2 km has been tested at highway E16 in the north of Stockholm. Two catenary trucks have been operated under this catenary system [Siemens 2016]. Another catenary system has been built in near the ports of Los Angeles and Long Beach. Three types of electric trucks, one battery-electric, one natural-gas hybrid-electric truck, and one diesel-hybrid truck are driving under a one-mile (1.6 km) catenary system on the north- and south-bound lanes of South Alameda Street from East Lomita Boulevard to the Dominguez Channel in Carson [Siemens & SCAQM 2017].

In Italy, a 6 km long catenary system is planned on the A35 between the Romano di Lombardia and Calcio exits. Photovoltaic panels along the A35 will generate the required electrical power for the operation of the catenary trucks [Scania 2018].

Figure 43 shows a prototype catenary truck at the testing site Gross-Dölln, Germany.

Figure 43: Prototype catenary truck

In this study a CEV without diesel engine has been assumed. Therefore the CEV is equipped with a 200 kWh battery for 140 to 160 km autonomy without catenary.

4.5 Results tank-to-wheel

The fuel consumption of the tractor truck has been derived from [Moultak et al. 2017]. The emissions of CH_4 and N_2O have been derived from [CPM 2013]. Table 42 shows the fuel consumption of the tractor trucks for 2020 and 2030.

Table 42: Fuel consumption and non-CO_2 GHG emissions 'tank-to-wheel' of the tractor truck

	Fuel consumption			Non-CO_2 GHG	
	MJ/km	kWh/km	l_{DE}/100 km	g CH_4/km	g N_2O/km
2020					
Diesel	12.0	3.33	33.4	0.024	0.073
CNG Otto cycle	14.0	3.89	39.0	0.778	0.070
LNG Otto cycle	14.0	3.89	39.0	0.778	0.070
LNG HPDI	13.0	3.61	36.2	0.025	0.079
FCEV	8.8	2.45	24.6	0.000	0.000
CEV	5.3	1.47	14.8	0.000	0.000
2030					
Diesel	9.0	2.50	25.1	0.018	0.055
CNG Otto cycle	11.0	3.06	30.7	0.612	0.055
LNG Otto cycle	11.0	3.06	30.7	0.612	0.055
LNG HPDI	10.0	2.78	27.9	0.020	0.061
FCEV	7.6	2.11	21.2	0.000	0.000
CEV	4.5	1.25	12.5	0.000	0.000

The fuel consumption does not correlate linearly with the efficiency because besides propulsion heating of the cabin is required in winter. In case of internal combustion engines and fuel cells the heat can be derived from the heat released by the engines and the fuel cells.

The emission limits for heavy duty trucks are related to the output of mechanical work of the engine (g per kWh of mechanical work). For conversion to values per MJ of fuel the efficiency of the engine has to be known.

The values for NMVOC, NO_x, and particulate matter (PM) emissions indicated in the LCA database of the Swedish Life Cycle Center have been derived from the Euro 6 emission limits via multiplication with an efficiency of 44% to get the emissions per energy unit of fuel in case of diesel engines. In case of gas engines an efficiency of 40% has been assumed [CPM 2013]. The SO_2 emissions can be derived from the sulfur content in the fuel. Table 43 shows the air pollutants from the operation of tractor trucks.

Table 43: Air pollutant emissions 'tank-to-wheel' of the tractor truck

	NMVOC (g/km)	NO_x (g/km)	SO_2 (g/km)	CO (g/km)	PM (g/km)
2020					
Diesel	0.211	0.675	0.003	5.867	0.015
CNG Otto cycle	0.249	0.716	0.000	6.216	0.016
LNG Otto cycle	0.249	0.716	0.000	6.216	0.016
LNG HPDI	0.229	0.731	0.000	5.867	0.016
FCEV	0.000	0.000	0.000	0.000	0.000
CEV	0.000	0.000	0.000	0.000	0.000
2030					
Diesel	0.158	0.506	0.002	5.867	0.011
CNG Otto cycle	0.196	0.562	0.000	4.884	0.012
LNG Otto cycle	0.196	0.562	0.000	4.884	0.012
LNG HPDI	0.176	0.562	0.000	5.867	0.012
FCEV	0.000	0.000	0.000	0.000	0.000
CEV	0.000	0.000	0.000	0.000	0.000

FCEV and CEV offer the advantage that there are no tailpipe emissions for greenhouse gases and air pollutants.

The CAPEX for the tractor trucks has been derived from [Moultak et al. 2017] by subtracting the CAPEX of the semi-trailer and applying an exchange rate of 0.9019 € per US$. The costs for maintenance, repair, overhead, insurance, driver salary, road toll, and axle taxis have been derive from [CNR 4/2018]. Table 44 shows the economic data for the tractor truck.

Table 44: Economic data for the tractor truck

	CAPEX (€)	Maintenance & repair (€/km)	Overhead, insurances (€/km	Driver salary & expenses (€/km)	Road toll & axle taxes (€/km)
2020					
Diesel	116,000	0.105	0.195	0.451	0.089
CNG Otto cycle	154,000				
LNG Otto cycle	142,000				
LNG HPDI	167,000				
FCEV	186,000				
CEV	178,000				
2030					
Diesel	129,000	0.105	0.195	0.451	0.089
CNG Otto cycle	146,000				
LNG Otto cycle	138,000				
LNG HPDI	162,000				
FCEV	145,000				
CEV	136,000				

The maintenance and repair consists of the replacement of tires, brake pads, shock absorbers, springs, and other spare parts. Only a small part is related to the engine (oil exchange, replacement of air filter and other engine related spare parts). The drive salary and expenses include the salary of the driver including the national insurance employer's contribution (0.365€/km), and the long distance travelling expenses (0.086 €/km). The road toll is indicated with 0.084 €/km and the axle tax with 516 € per year (0.0045 €/km for an annual mileage of 114,100 km).

It has been assumed that the cost of maintenance and repair is the same for all drivetrains because the main cost components are the same for all drivetrains. FCEV and CEV need no exchange of engine oil. On the other hand in case of the CEV wearing parts of the pantograph has to be replaced. The air filter used in FCEV may be more expensive than that for internal combustion engines.

5 SYNTHESIS (WELL-TO-WHEEL)

The results from 'well-to-tank' (chapter 2) and 'tank-to-wheel' (chapter 3) are collated in this chapter in order to gain full pathway ('well-to-wheel') results and draw conclusions from this regarding promising fuel/powertrain combinations for trucks.

5.1 Environmental performance

Figure 44 and Figure 45 show the greenhouse gas emissions well-to-wheel for various transportation fuels in 2020 and 2030 respectively. In case of renewable transportation fuels the tank-to-wheel greenhouse gas emissions come from emissions of CH_4 and N_2O.

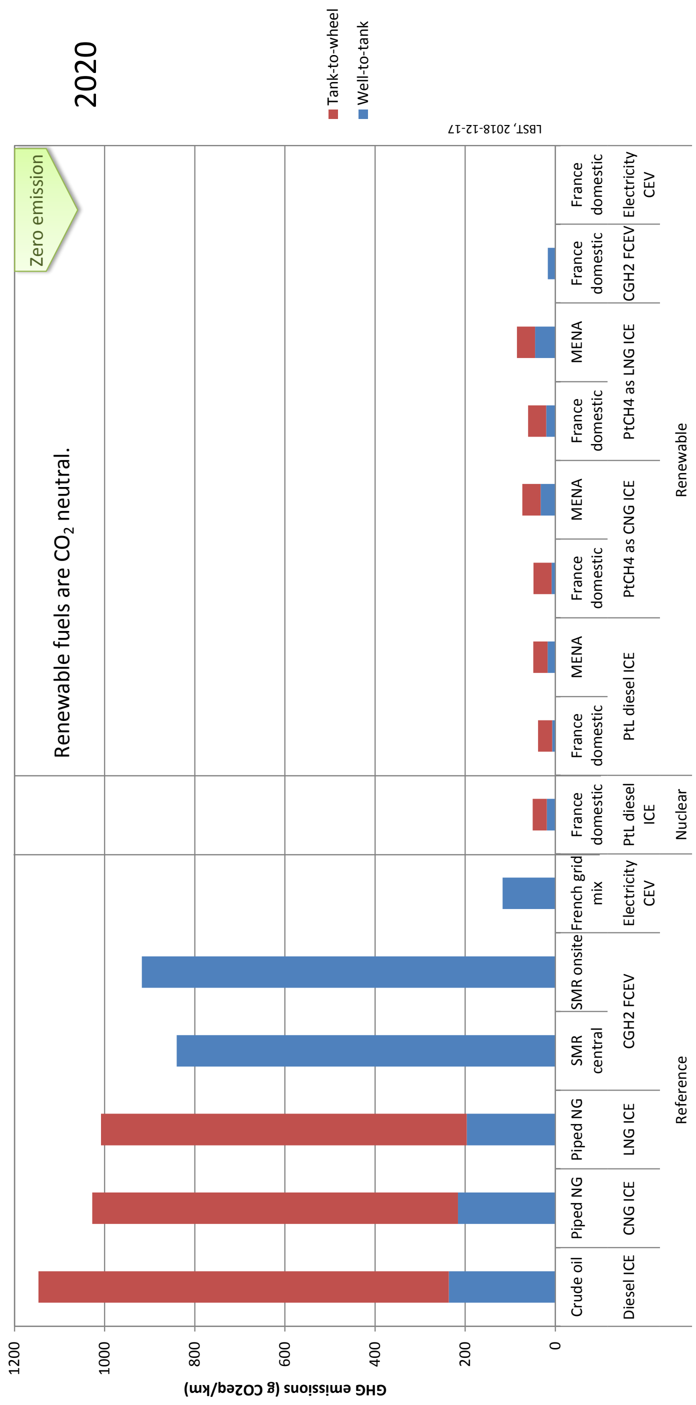


Figure 44: Greenhouse gas emissions well-to-wheel 2020

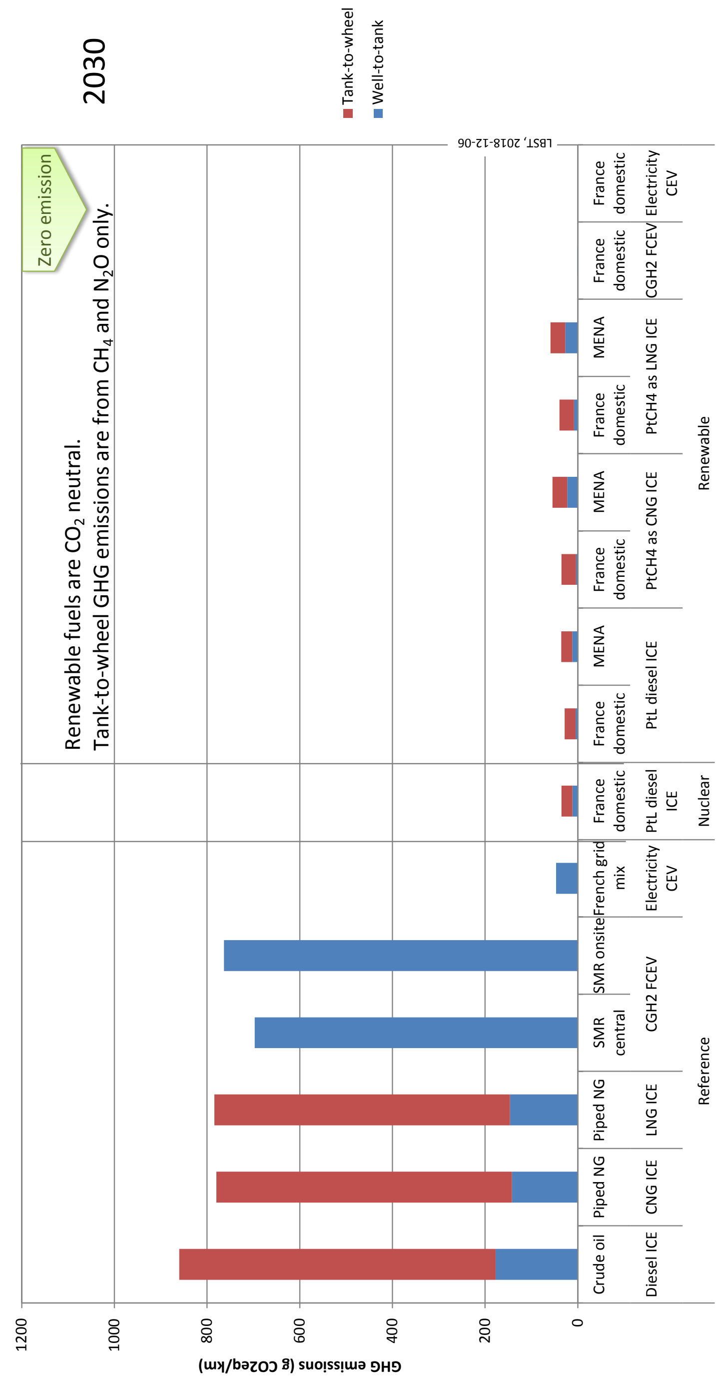


Figure 45: Greenhouse gas emissions well-to-wheel 2030

The consumption of nuclear electricity for the supply of synthetic diesel via power-to-liquid leads to about 22.3 mg and 13.3 mg of **radioactive waste** per km in 2020 and 2030 respectively (see Figure 61 and Figure 62 in Annex A1.2). The amount of radioactive waste decreases due the higher efficiency of the electrolysis plants, the energy consumption of the vehicle, and in case of electricity from the grid mix due to the lower share of nuclear electricity in 2030.

5.2 Energy use

Figure 46 and Figure 47 show the energy use well-to-wheel various transportation fuels in 2020 and 2030 respectively, split into fossil, nuclear and renewable energy.

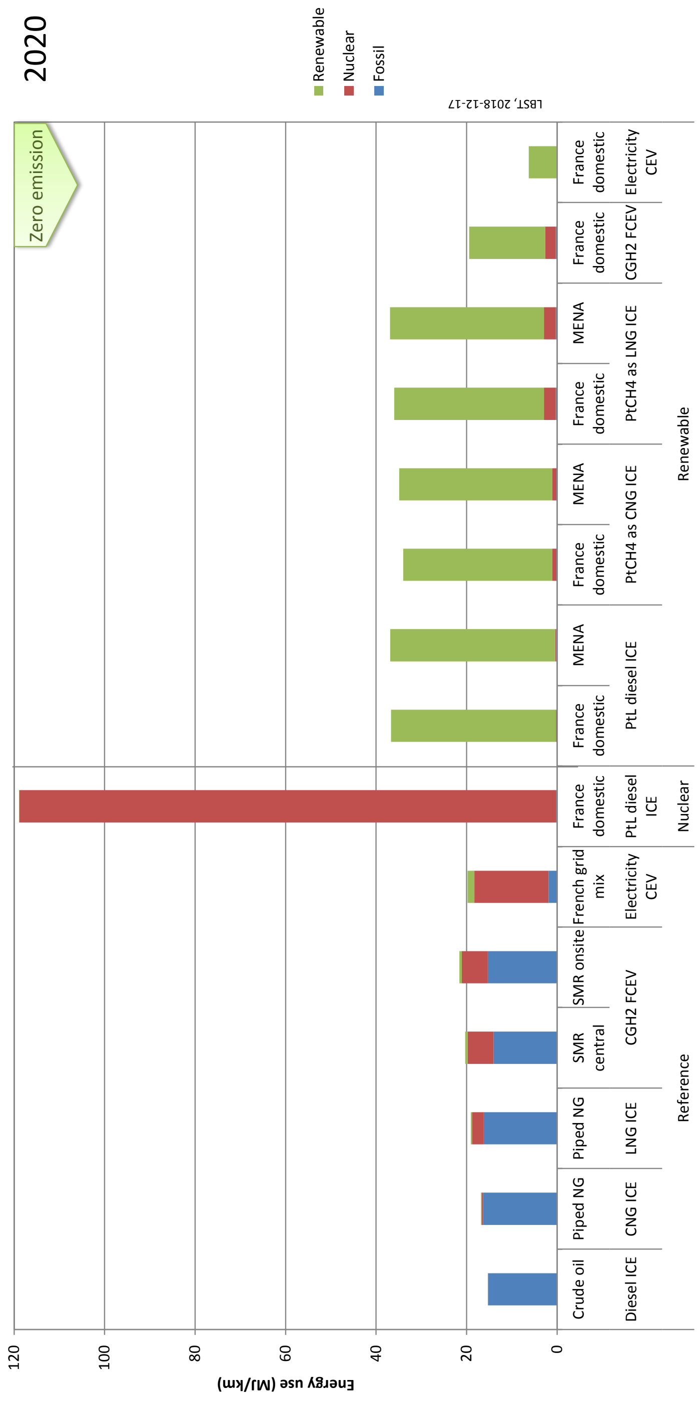


Figure 46: Energy use well-to-wheel in 2020

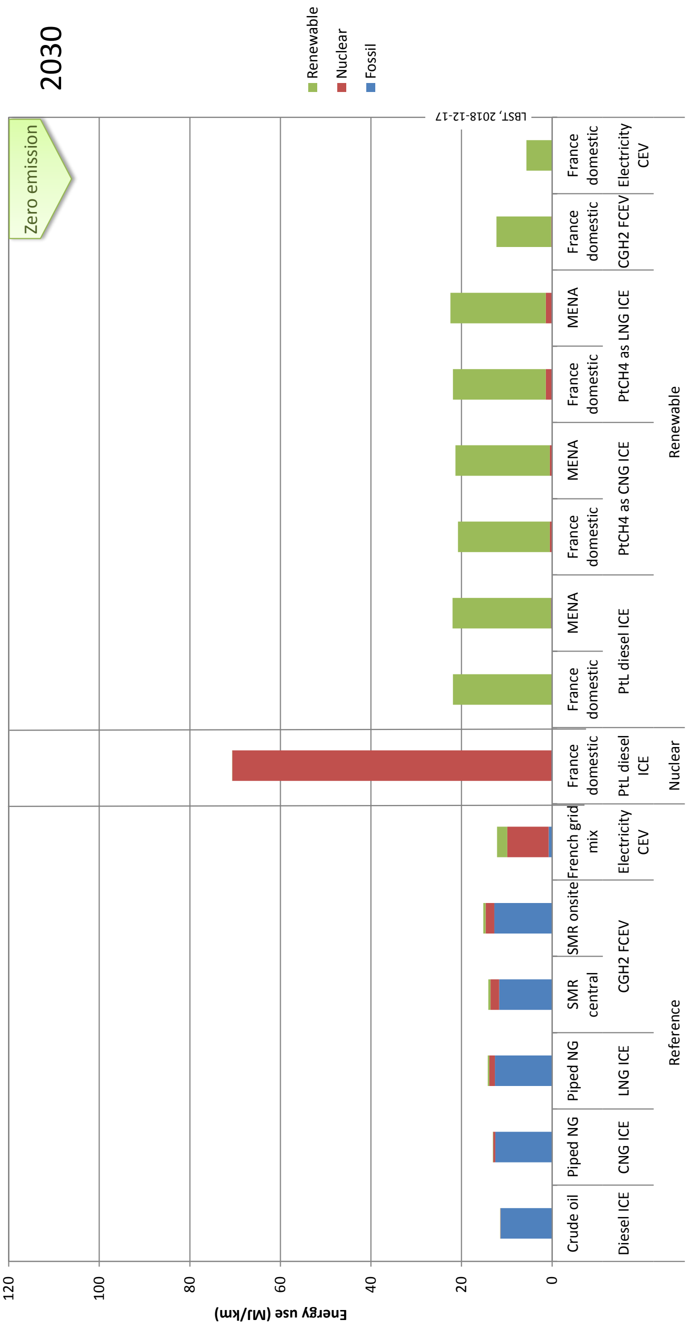


Figure 47: Energy use well-to-wheel in 2030

The high energy use for electricity for catenary electric vehicles from nuclear power result from the efficiency of the nuclear power plant (37%). The energy use is based on the heat released by nuclear fission.

5.3 Total cost of ownership (TCO)

Figure 48 and Figure 49 show the total cost of ownership (TCO) in 2020 and 2030 respectively.

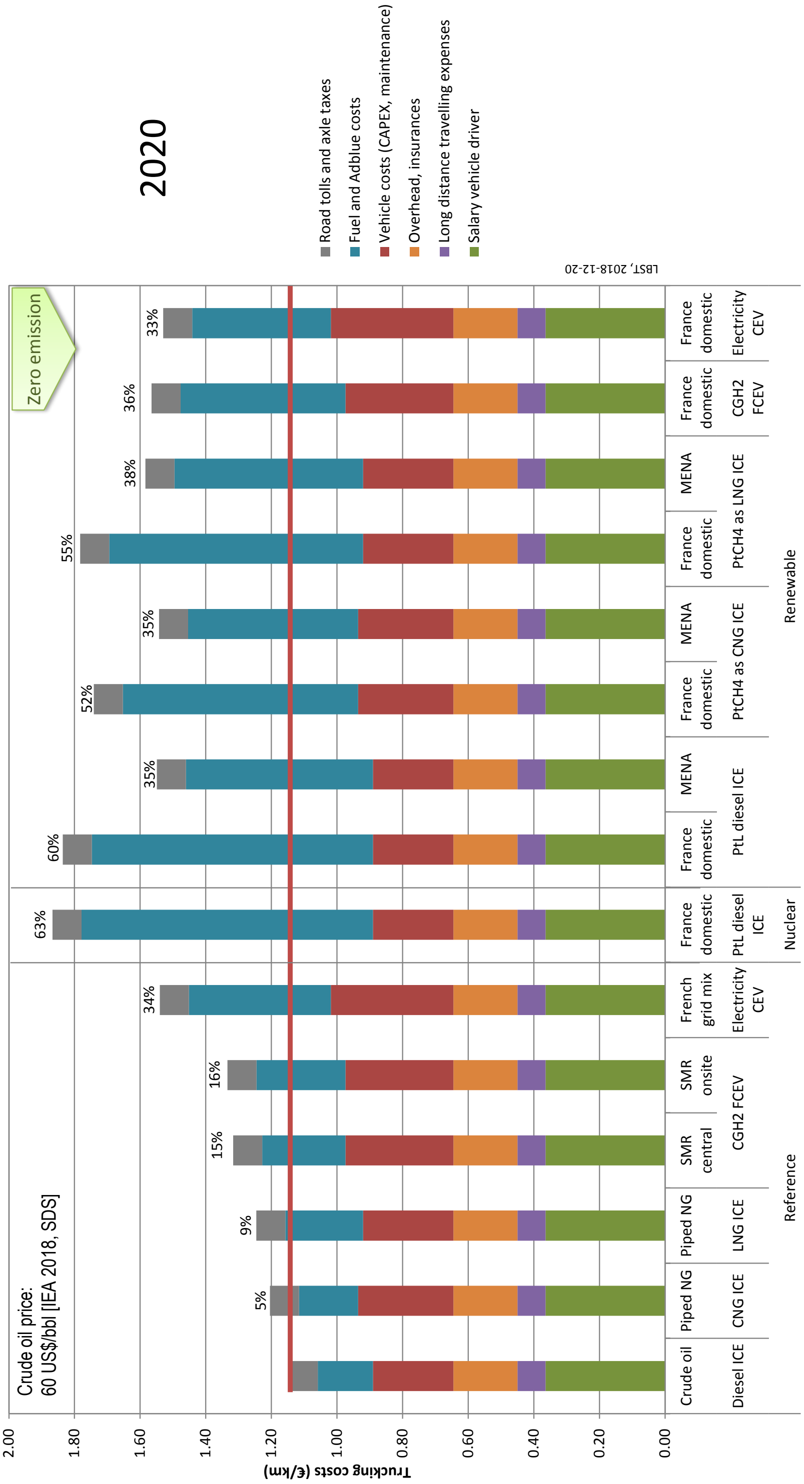


Figure 48: Total cost of ownership (TCO) 2020 (€/km)

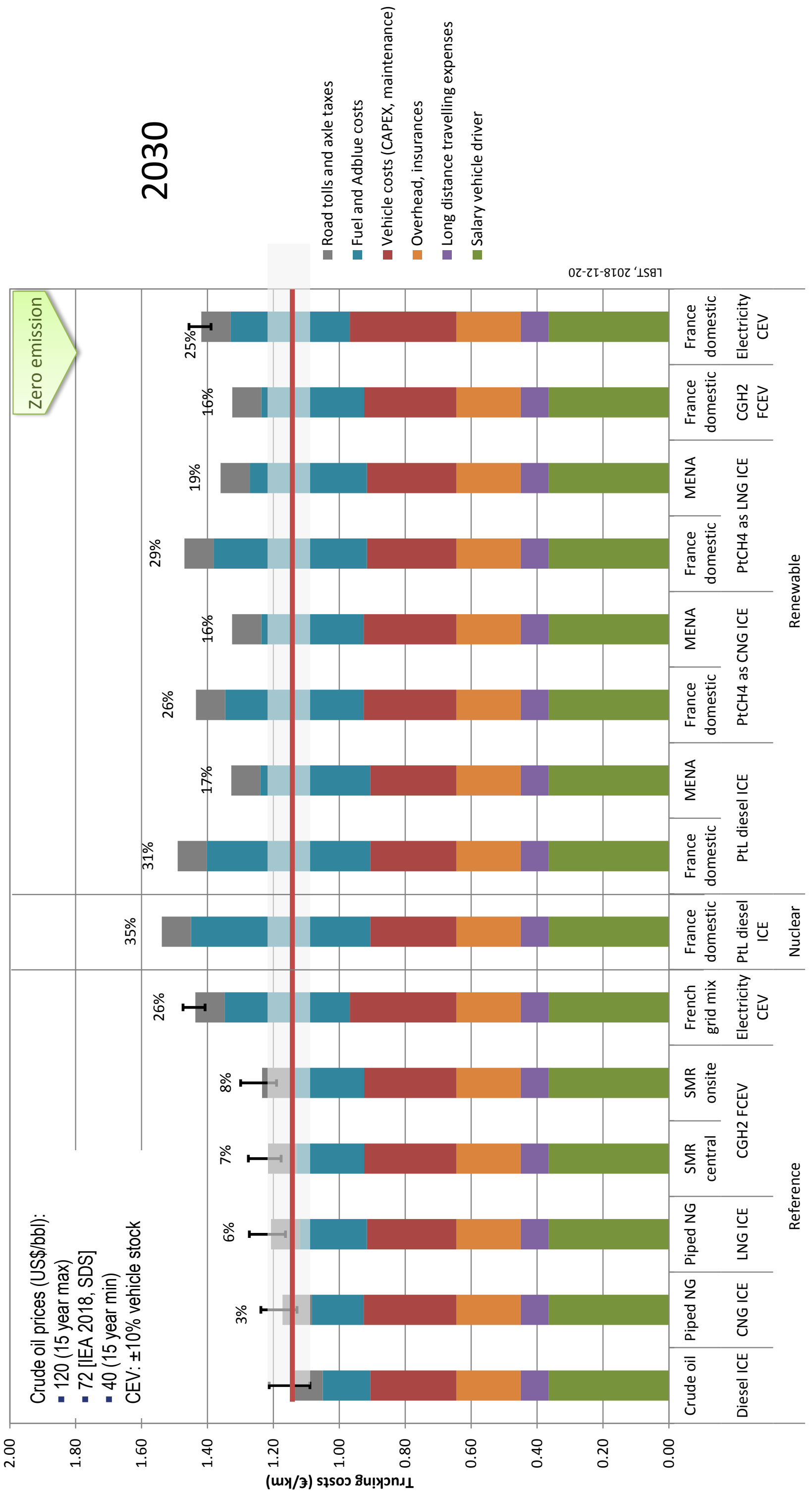


Figure 49: Total cost of ownership (TCO) 2030 (€/km)

The costs of electricity from new fossil, nuclear, and renewable power are converging. The costs of truck powertrains also are converging, series production provided.

In 2030, the incremental total cost of ownership (TCO) for FCEV using hydrogen from renewable electricity compared to crude oil based diesel fueled trucks amounts to about 16 %, the incremental costs of that for CEV using renewable electricity amounts to about 25%. The TCO of CEV also depends on the utilization of the catenary infrastructure. A decreasing vehicle stock using the catenary infrastructure leads to higher TCO. The error bar for CEV shows the influence of a variation of the vehicles stock of ±10%.

5.4 Cumulative investment

Based on tractor-truck market scenario in France, a market introduction scenario for alternative fuels and powertrains has been assumed. For all alternative powertrains, the same deployment rate (ceteris paribus) has been assumed. Based on the scenario in this study, in 2030 the total number of tractor trucks will amount to about 210,000 units, thereof some 150,000 are used for long-haul transport.

There is a continuous stock roll-over, i.e. there is no early force-out of legacy vehicles. Table 45 shows the development of vehicle stock and new vehicle registrations.

Table 45: Development of vehicle stock and new vehicle registrations

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Development of vehicle stock (long-haul total)	144,650	144,493	144,554	144,805	145,222	145,784	146,474	147,276	148,176	149,163	150,229
Legacy vehicles operated with Diesel from crude oil	143,462	141,189	137,579	131,916	123,686	112,868	99,921	85,490	70,141	54,262	38,091
# of vehicles going out because of age (9 years avrg.)	16,505	16,505	16,505	16,505	16,505	16,505	16,505	16,505	16,505	16,505	16,505
# of vehicles going in (replacement + growth)	16,505	16,348	16,566	16,756	16,921	17,067	17,194	17,306	17,405	17,492	17,570
Share of alternative vehicles in new vehicles (ceteris paribus: CNG or LNG or FCEV or CEV)	7%	13%	22%	35%	51%	67%	79%	88%	93%	96%	98%
# of alternative fuel-powered new vehicles	1,189	2116	3,672	5,914	8,646	11,381	13,637	15,232	16,250	16,866	17,236
Stock of alternative fuel-powered vehicles	1,189	3,304	6,976	12,890	21,536	32,916	46,553	61,785	78,035	94,902	112,137

While 98 % of new vehicles in 2030 come with alternative fuel/drivetrains, about 75 % of the vehicle fleet and fuel consumed are alternative fuels and powertrains only.

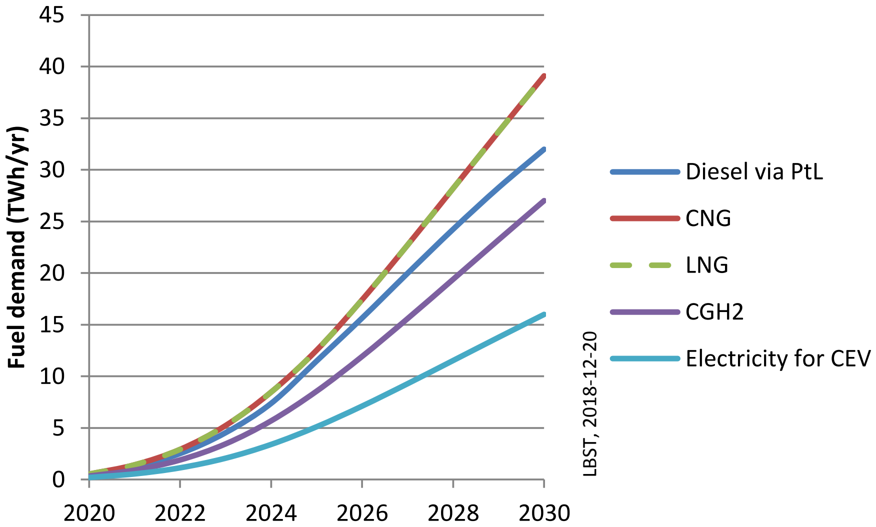


Figure 50: Development of the annual demand of alternative transportation fuels ('ceteris paribus')

Figure 51 shows the Development of the annual electricity demand for alternative fuels until 2030.

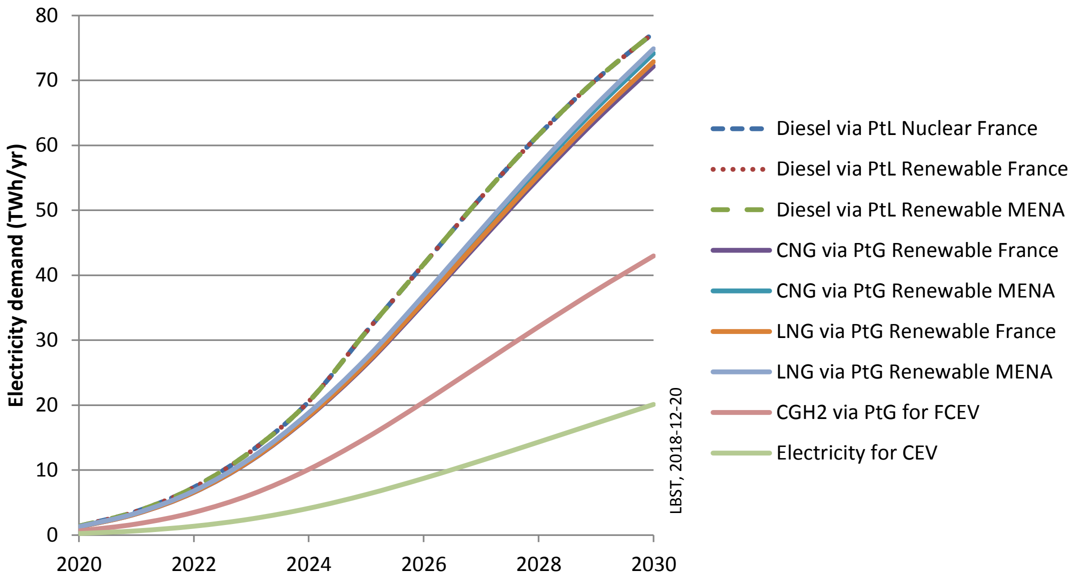


Figure 51: Development of the annual electricity demand for alternative fuels ('ceteris paribus')

In case of synthetic diesel via power-to liquid about 15% of electricity generation in France in 2017 (529 TWh) would be required. In case of hydrogen for FCEV about 8% of today's electricity generation in France would be required.

The market penetration of alternative fuels and power trains leads to the reduction of greenhouse gas emissions as shown in Figure 52.

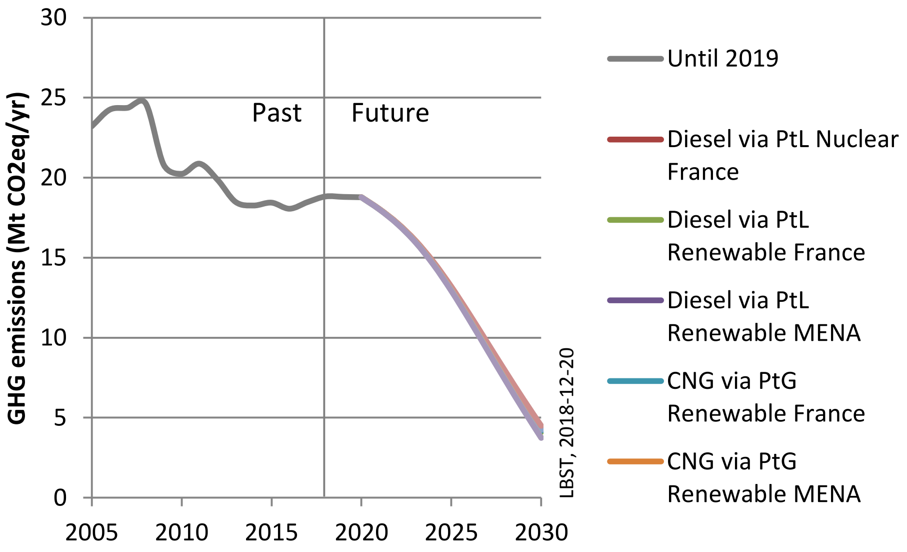


Figure 52: Development of greenhouse gas emissions from tractor trucks assuming 'ceteris paribus' market penetration

The greenhouse gas emissions include the greenhouse gas emissions from the supply of the fuels including crude extraction, transport, refining, and distribution of fossil diesel. The greenhouse gas emissions also include tailpipe emissions of CH_4 and N_2O.

Past greenhouse gas emission reductions were mainly due to fewer tractor trucks, decreasing annual mileage, and slight reductions in fuel consumption. All fuel/powertrain combinations analysed in this study could have the potential for greenhouse gas emission reductions of between 76 to 80 % until 2030 compared to those in 2020. Remaining greenhouse gas emissions in 2030 are due to the legacy vehicles in the fleet using fossil diesel.

Figure 53 shows the development of the specific investment for the PtX plants.

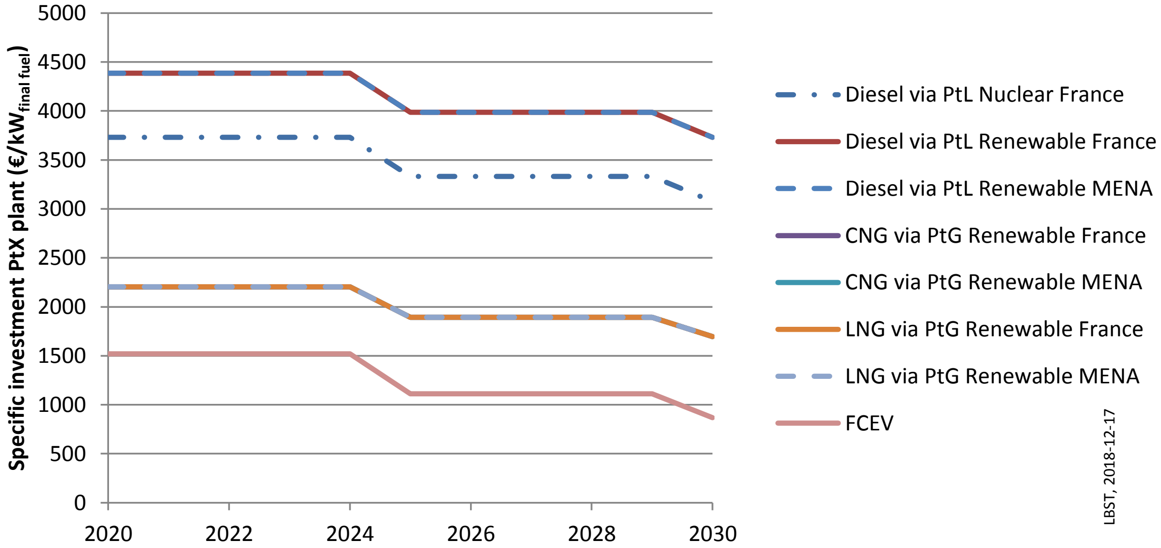


Figure 53: Development of the specific investment for PtX plants

Figure 54 shows the cumulative investment for various pathways. The cumulative investment comprises the renewable power plants, the fuel production plants (PtX plants), the alternative fuel infrastructure, for transport, and distribution, and the vehicles (including re-investments for vehicle end-of-life replacements).

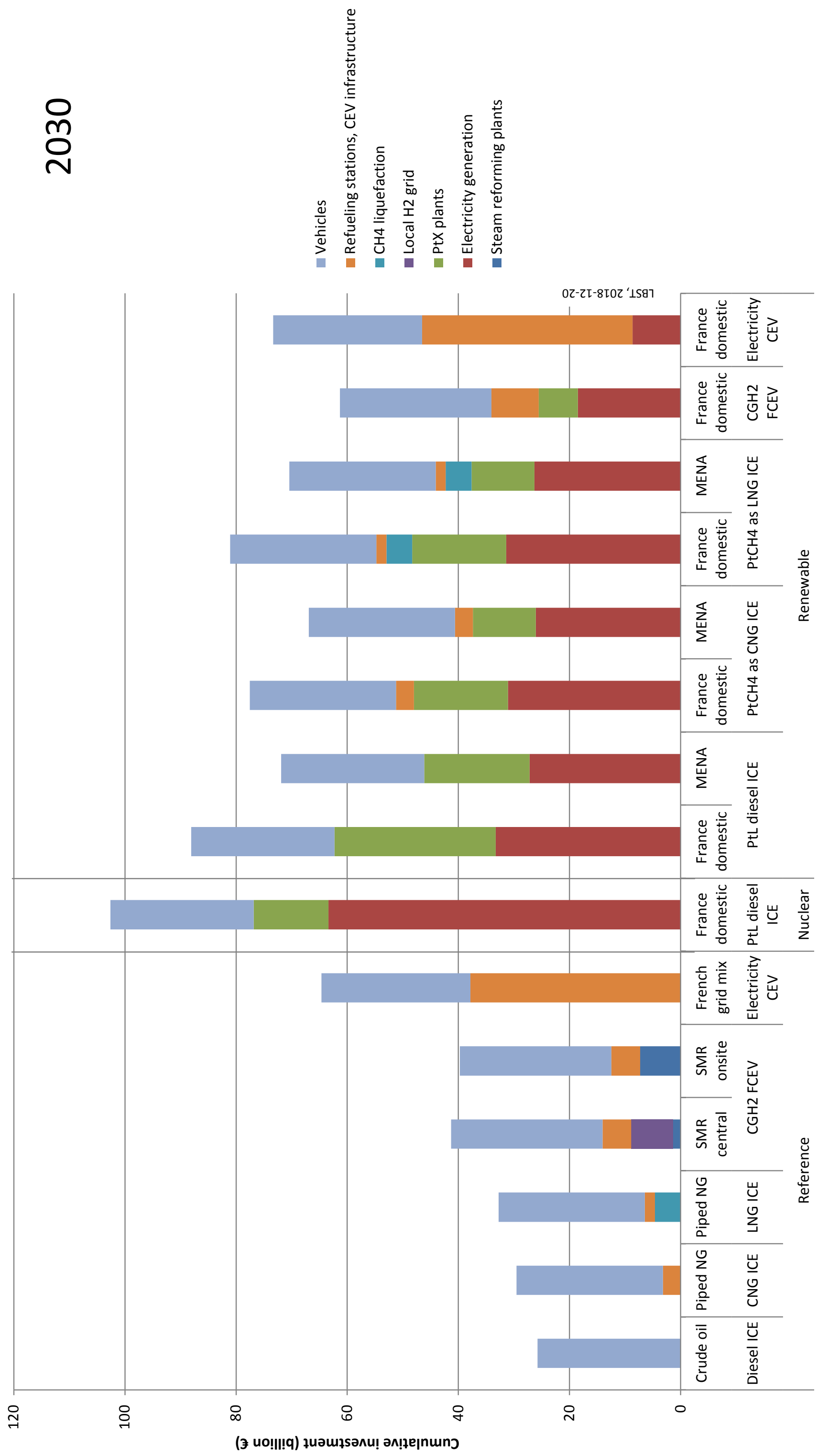


Figure 54: Cumulated investments until 2030 (‘ceteris paribus’)

The cumulative investment has to be compared with the gross domestic product (GDP) of France in 2017 (2292 billion €). About 3.5% of the French GDP in 2017 would be required for an investment of 80 billion € until 2030.

5.5 Advantages and disadvantages of alternative fuel/powertrain combination investigated

With a view to the climate budget approach and technology cost paths, 'bridge options' based on marginal cost assessments are not an option. Key criteria for the determination of promising, long-term robust fuel/powertrains for greenhouse gas neutral long-distance trucks are shown in Table 46.

Table 46: Study results concerning key criteria for favourable heavy-duty vehicle fuel/powertrain combinations

Criteria	Study results
Costs	All renewable pathways investigated offer a perspective, series production provided ⇒ other criteria are of strategic importance
Greenhouse gas emission reduction	All renewable/nuclear pathways have zero GHG-capability. Sustainability of (concentrated) CO_2 source is of importance
Air pollutant emissions	Robust zero with electric powertrains only (FCEV, battery CEV)
Energy demand (well-to-wheel)	Rule-of-thumb: energy demand increases with increasing hydro-carbon chain length and use of combustion engine
Established fuel infrastructure	Diesel, CNG
Established powertrain technology	Internal combustion engine
Synergies with other uses	CEV uses exclusive infrastructure

The advantage of synthetic diesel via power-to-liquid is, that as a drop-in fuel existing fuel infrastructures and powertrains can be used. The disadvantages are high energy demand leading to approximately double electrolysis capacity and the emissions of air pollutants. The cumulative investment is at the upper end of the assessed fuel/powertrain combinations due to the low efficiency of the power-to-liquid plant.

The advantage of synthetic methane via power-to-methane is, that existing natural gas infrastructure and engine technology can be used. Disadvantages are the higher energy demand compared to FCEV leading to approximately double electrolysis capacity and the requirement of a refueling station network for CNG vehicles has to be expanded. The energy requirement is higher energy than for FCEV and CEV. There are still some air pollutant emissions (ultra-low in case of Otto cycle).

Due to the electric powertrain, FCEV and CEV offer zero greenhouse gas emissions, zero air pollutant emissions, and a reduced noise signature at lower speeds.

The well-to-wheel energy demand of FCEV is significantly lower than that of drivetrains involving combustion engines. The disadvantage of FCEV is the requirement of a new refueling station network for CGH_2 vehicles. FCEV shares the technology basis and infrastructure with other hydrogen uses e.g. buses and passenger vehicles.

CEV offer the lowest well-to-wheel energy requirement. However, during winter additional electricity is required for heating the cabin. Therefore, the difference in average tank-to-wheel energy consumption over the whole year between CEV and FCEV decreases. The difference is lower than may appear if only drivetrain efficiencies are compared with each other.

The disadvantage of CEV is the requirement of a catenary infrastructure. The catenary system is exclusive to (relatively few) long-distance trucks (and possibly buses). CEV competes with rail freight (and possibly public rail transport in case of catenary buses). CEV are Ideal for frequent point-to-point relations.

Series production provided, costs of alternative truck powertrains are converging within uncertainties of future cost estimations. Costs of new fossil, nuclear and renewable electricity have already converged. The costs of imported synthetic fuels (synthetic methane via power-to-methane, synthetic diesel via power-to-liquid) are about 20 % lower than those from domestic production.

The FCEV drivetrain offer low cumulative investment among the renewable options. The cumulative investments seem manageable for all options with some 0.35 % of French gross domestic product (GDP)[4] in average annual investments between 2020 and 2030 for an energy transition in heavy-duty trucking. This includes investments which would otherwise have to be made anyway, i.e. new vehicle CAPEX for diesel trucks. Furthermore, there are additional benefits from decreasing annual expenditures for fossil fuel imports.

[4] GDP in France in 2017: 2292 billion €

6 CONCLUSIONS & RECOMMENDATIONS

FCEVs and CEVs are the two most promising, long-term robust fuel/powertrains for greenhouse gas neutral heavy-duty trucks as concluded from the previous section.

This section lays out the key pillars of a successful short-to-mid-term introduction strategy and provides specific regulatory and policy recommendations, based on a high-level assessment of market entry barriers for both FCEVs and CEVs.

First of all, FCEVs and CEVs face a similar set of challenges, mostly having to do with the “chicken and egg dilemma”, as both deployments consist in putting onto the market innovative and (initially) expensive-to-make vehicles supported by a still non-existent capital-intensive infrastructure[5]. These barriers can be broken down in four categories: infrastructure business case, vehicle technology, OEM and value chain readiness, regulatory framework.

Infrastructure business case

The lack of long-term visibility on sufficient amount of demand is a challenge to justify the investment in the supporting infrastructure (production units & refuelling/distribution infrastructure), which tends to hinder the initial investment. The high entry ticket as well as the high resulting fuel cost are also two other major barriers making the business case unfavourable both for the infrastructure and the fleet operators.

Table 47: CEV / FCEV infrastructure related challenges for roll-out

CEV	FCEV
▪ CAPEX: 1.67 M€/km of catenary line (16 M€/10 km, 84 M€/50 km, 335 M€/200 km) ▪ Minimum demand of 5 to 6 vehicles per km of catenary line to bring TCO down to acceptable levels (50-60 vehicles /10 km, 250-300 /50 km, 1000-1200 /200 km, etc.). ▪ Dedicated infrastructure with no possible synergies ▪ Infrastructure governance and business model complexity (who pays what, who maintains, etc.)	▪ On-site infrastructure requires minimal H_2 demand of 400 kg/d (>10-15 trucks of daily demand) ▪ A 400 kg/d electrolyser + refueling station involves approx. 3-4 M€ CAPEX

5 A characteristic common to all new/alternative fuel infrastructures, including CNG and LNG for HDV.

Vehicle technology

There is a sizeable technology risk linked to the deployment of FCEV and CEV trucks, since both technologies are yet unmatured and new to the market. This has a significant impact on the risk profile of the investment both on the fleet and infrastructure sides. Additionally, low manufacturing volumes imply **high purchase prices** for fleet operators, which result in a **TCO higher than incumbent technologies (diesel)** in the initial introduction period.

Operational risk aversion to switch to alternative fuel/powertrain solutions will hinder early investment in CEV and FCEV technologies from small to medium companies. Fleet operators cannot afford to have trucks that are not available as their revenues rely on their trucks' availability. The perceived risk of switching a large percentage of one's fleet to an alternative technology is a barrier to investment. A sufficiently large fleet is critical for low TCO. The larger the fleet of the operator, the less a fleet of (e.g.) 10 to 15 FCEV trucks is critical within their overall operations.

Table 48: CEV / FCEV vehicle related challenges for roll-out

CEV	FCEV
▪ 2018 TRL: 7-8 → there are only a few pilot projects running in the world (USA, DE, SWE…) ▪ 2020 TCO is still 30-35% higher than diesel ▪ Vehicle purchase price: 178 k€ (+53% diesel)	▪ 2018 TRL: 7-8 → there are only a (few) pilot projects running in the world (USA, NL, NO, CH, …) ▪ 2020 TCO 30-35% higher than diesel ▪ Vehicle purchase price: 186 k€ (+60% diesel)

OEMs and vehicle value chain readiness

The upfront investment in a production line is very high but the lack of visibility on long-term demand for FCEVs and CEVs does not create a favourable investment climate for OEMs and across the value chain (tier 1, 2, etc.). Some OEMs hint towards the fact that a common platform could be used for all electric vehicles (BEV, FCEV, CEV, PHEV), which could lower the risks and the entry ticket. Up until now, there has been no commercial FCEV nor CEV tractor models available on the marketplace (commercial availability is being announced towards 2020-2023 at the latest). This uncertainty stems from yet-to-be stabilized regulatory and policy framework to support low emission tractor trucks in general combined with a very intense competition landscape, making it impossible to predict the actual future market shares of individual technology options. It is also noteworthy that the lack of vehicle value chain readiness tends to add risk for both the fleet and the infrastructure operators as it impacts the reliability as well as the availability of the vehicles.

Table 49: Market readiness of CEV / FCEV

CEV	FCEV
▪ Only a few tractor OEMs are positioned today on CEVs (Scania, Volvo trucks) ▪ No commercial plans yet announced.	▪ Only a few tractor OEMs are positioned today on FCEVs (Hyundai, Toyota, Nikola, VDL, DAF, Kenworth) ▪ The only EU players positioned today in funded projects are VDL, Scania and DAF . Other players positioning themselves in HD FC trucks are Daimler, IVECO and MAN. ▪ Hyundai announced the supply of 1000 FCEV rigid trucks to the Swiss market from 2019 to 2023. (Hyundai sells also a diesel tractor model and considers a fuel cell one) ▪ Nikola announced its model Tre will be ready for EU markets for 2022-23

Finally, looking at specifically the regulatory framework surrounding the CEV infrastructure, there are still some highway safety issues that have to be addressed. Installing catenary lines can pose some safety challenges on highways, related to the placement of the lines. Installing the infrastructure on the left lane will reduce investment thanks to only one pole supporting traffic in both directions, however it will mean that all HDVs will use the left lane, posing a highway safety and regulation problem. Also, the CEV infrastructure is not mentioned in the alternative fuel infrastructure directive (AFID 2014/94/EU), which cites hydrogen as being an option, however which does not cite highway catenary lines. Therefore, there could be interoperability issues between member states (MS).

6.2 FCEV market introduction strategy

Key principles for building a sound hydrogen infrastructure business case

To build a sound business case for the fuel production and supply infrastructure, the key success factors are the following:

- To secure a long-term supply contract with one or several large fleet, justifying the investment in the upstream production and supply infrastructure;
- To ensure fuel cost competitiveness for the end client (already facing high vehicle costs and risks) via economies of scale;
- To reach acceptable profitability levels to still make the case attractive for the investor and operator.

Long-term supply contract(s) with one or several fleet operators are needed to justify an investment in production and distribution infrastructure. Moreover, in the early phase of alternative powertrain deployment, only large fleets (>50) will enable enough economies of scale across the fuel supply chain to reduce the costs of hydrogen at the pump. For the sake of competitiveness, and even though the long-term goal will be to source exclusively dedicated renewable capacities, the procurement of electricity (e.g. certified renewable or low-carbon) obtained from the grid assists to reduce costs in the short-term while ensuring a high utilization rate and low-carbon footprint. Grid connection is a prerequisite for providing grid services that facilitate integration of fluctuating renewable power, inclusion of base-load (nuclear) thermal power plants and allow for potential additional revenues.

Depending on the local context, economies of scales can be further obtained by supplying hydrogen to other nearby fleets (light-duty vehicles, rigid trucks, buses, vans, forklift trucks, etc.) or industry users, which also generates additional sales. In the short-term, injecting hydrogen in the gas grid injection can de-risk the infrastructure investment, provide additional revenue and could trigger cost reductions through economies of scale.

Finally, a MW-size (minimum) electrolyser could also possibly provide valuable ancillary services to the electricity TSO (and depending on the context to the DNO/DSO as well). Electrolysers are flexible load that can provide low-cost balancing services (up and down) to the grid while operated for mobility, industry or natural gas injection. Electrolysers (PEM in particular) are able to provide such balancing services (i.e. both upwards and downwards adjustment capability) while operating at nominal load for mobility, industry, or hydrogen injection. Consequently, the marginal cost of these services is minimal. The associated revenue stream can be considered as a discount on the electricity price, which can go up to 18 €/MWh [HIN & TE 2017].

Fleet operator business case and risk profile

On the fleet operator side, the key success factors will be the following:

- The type of fleets and using pattern
- The size of fleets
- The exposure to societal pressures
- The share of transport in the final retail price of the good transported
- Captive fleets with daily driving distances below current vehicle range (300-400km) should be targeted in priority. Such fleets will allow infrastructure investors to lower the entry barrier, as there will be less stations to be deployed, and will allow long-term visibility on demand.

The case will be more attractive for large fleet (>50) operators as they will immediately unlock economies of scale resulting in a lower TCO. Bulk vehicle orders will also create a better investment climate for the OEMs, thus reducing both risks and total industrialization costs (at a society level). Finally, the commissioning of large fleets will contribute to reducing operational risks for the fleet operator (and the consequential financial risk for the infrastructure operator), as spare part will become readily available and maintenance more reliable.

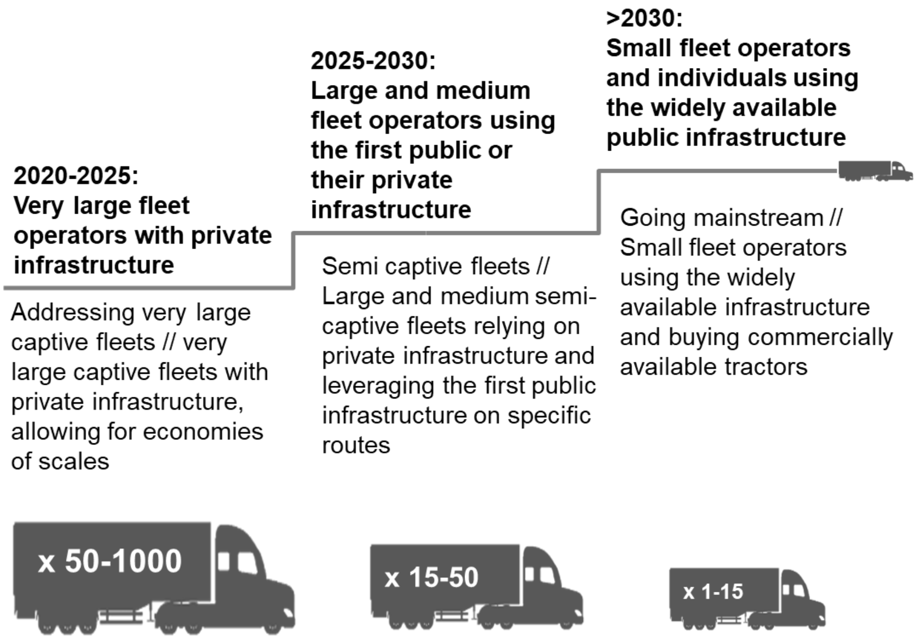


Figure 55: Expected roadmap towards achieving FCEVs as a universal solution

In additional to that, societal pressure is starting to apply on retailers and brands and will have repercussions upstream in the value chain including on transport operators. **The fleets the most exposed to societal pressures should be targeted in priority.** Today, we are already witnessing large supermarket chains, such as Asko (NO), Carrefour (EU) and COOP (CH), and brands such as Anheuser-Bush (USA) leading the way to convert their fleets to zero-emission.

Finally, transport of high added-value products (>35,000 €/t) will be least sensitive to costs increase due to more expensive vehicles and fuel. Higher transport costs will least affect the price of high-added value products of all products. End-consumer willingness to pay therefore is more likely for high added-value products, where the price increase is not as visible as on other lower added-value products.

6.3 CEV tractor market introduction strategy

Contrary to FCEVs, CEV costs are highly sensitive regarding infrastructure utilisation. This technology recommends itself to be deployed on specific routes for high-traffic point-to-point logistics to minimise risks of stranded (infrastructure) investments. In the short-term, the best option is to concentrate efforts on a limited number of lines and very large fleets operating along routes with point-to-point relations in order to prove the technology in real-world environment, create a critical mass and rapidly trigger costs reductions.

The key principles for a successful short-term introduction strategy for CEVs are very close to the ones laid out previously for FCEVs.

On the **infrastructure side**, the key success factors will be:

- To secure a long-term supply contract with several (>5-10) large fleet, justifying the investment in the catenary infrastructure;
- To ensure fuel cost competitiveness for the end client (already facing high vehicle costs and risks) via economies of scale;
- To reach acceptable profitability levels to still make the case attractive for the investor and operator.

Key success factors on the **fleet side**:

- The type of fleets and using pattern
- The size of fleets
- The exposure to societal pressures
- The share of transport in the final retail price of the good transported
- Captive fleets with daily driving distances below current vehicle range (300-400km) should be targeted in priority. Such fleets will allow infrastructure investors to lower the entry barrier, as there will be less stations to be deployed, and will allow long-term visibility on demand.

The key success factors here are by and large similar to the hydrogen infrastructure: Secure a long-term electricity supply contract to one or several captive fleets ensure electricity cost competitiveness and finally to reach acceptable profitability levels.

Getting to a critical size of five to six vehicles per km of catenary line is a key success factor to obtain competitive fuel prices. CEV tractors are today in competition with several other technologies to obtain a market share in the future. In a TCO driven market, getting fuel costs down is a priority and CEV tractors will only get their edge to the competition if the TCO is competitive to other similar solutions. In the short-term, the infrastructure investor will thus need to secure five to six vehicles to push the market uptake of CEV tractors thanks to low fuel costs and competitive TCO.

Long-term supply contract(s) with several (>5-10) fleet operators running on a specific route are needed to justify an investment in the catenary infrastructure. As long-haul tractors usually drive on average 497 km per day [CNR 4/2018], very long corridors need to be decarbonised. As a first assumption in the previous section, the corridor Paris-Lille (211km) is first electrified with the investment spread over 1200 tractors. Smaller scale projects could first see the light on smaller highway sections in France on a case by case basis. However, as large fleet operators (> 50 employees) have on average 62 trucks [CNR 4/2018], this means that several fleet operators that are operating daily on the same corridor need to join forces to justify an investment in the infrastructure on a meaningful scale, due to the large critical mass needed to obtain competitive fuel prices.

The catenary infrastructure can also be mutualized with other catenary consumers such as other heavy-duty vehicle, namely rigid trucks or coaches. However, due to the large critical mass needed to justify an investment, these users will not suffice to justify an investment in the infrastructure by themselves. They could provide nevertheless an additional revenue to the infrastructure investor. CEV tractors are also able to provide valuable demand response to the electricity TSO (and depending on the context to the DNO/DSO as well). However, the need and the value of this service are difficult to estimate, as the tractors are not able to provide the same services as an electrolyser and a significant system development is required to measure efficiently the influence of each tractor using the line.

Looking at the fleet operator business case, key success factors will depend on type of fleets, size of fleets, visibility and types of goods transported.

In the case of CEV tractors, the only possible route that is relevant to a catenary truck is point-to-point logistics. CEV tractors have a relatively small battery on-board which allows them to drive the last mile distance from the end of the line to the destination. Which means that we are looking at a region-to-region route, driven on a daily basis and that uses the same corridor, or highway, to get from the one point to another. CEV tractors thus only allow for a single corridor to be decarbonised.

Similarly to FCEVs, the case will be more attractive for large fleet (>50) operators as they will immediately unlock economies of scale resulting in a lower TCO. Bulk vehicle orders will also create a better investment climate for the OEMs, thus reducing both risks and total industrialization costs (at a society level). Finally, the commissioning of large fleets will contribute to reducing operational risks for the fleet operator (and the consequential financial risk for the infrastructure operator), as spare part will become readily available and maintenance more reliable.

The fleets the most exposed to societal pressures should be targeted in priority. Today, we are already witnessing large supermarket chains, such as Akso (NO), Carrefour (EU) and COOP (CH), and brands such as Anheuser-Bush (USA) leading the way to convert their fleets to zero-emission with FCEV drivetrains.

Finally, transport of high added-value products (>35,000 €/t) will be least sensitive costs increase due to more expensive vehicles and fuel. Higher transport costs will least affect the price of high-added value products of all products. End-consumer willingness to pay therefore is more likely for high added-value products, where the price increase is not as visible as on other lower added-value products.

6.4 Policy recommendations

To achieve rapid scale-up, a stable and supportive policy framework would be needed to encourage the appropriate level of private investments.

The initial trigger will have to come from market pull regulation measures. Such instruments may include carbon pricing, emissions restrictions (low-emission

zones, emissions requirements or targets, road and axle taxes linked to emissions), specific mandates for renewable energy content, etc.
More specifically, road tolls and axle taxes, which account for 6,9% of the TCO of long-haul tractors in France, could be partially (or completely) exempted for zero-emission trucks and could help to enable a sound business case and thus justify private investments.
As of today, no regulatory pull favouring the adoption of zero-emission HDVs, neither at the EU level nor at the French national level, was identified. In the mid-term (2020s) at the EU level, the implementation of the RED 2, the Eurovignette and the CO2 emission requirements for HDVs were the main drivers supporting zero-emission tractors.

Regulatory measures targeting zero-emission vehicle quotas on the fleet operator side as well as on the OEM side, could push OEMs to invest in factories and push the value chain to structure itself more rapidly.

However, in the initial deployment phase as FCEVs and CEVs tractors remain more expensive than conventional technologies, market push instruments will be needed to cover the cost difference and incentivise fleet operators to make the switch. As both the CAPEX surplus and the higher TCO are two of the main barriers facing CEV and FCEV tractors, lowering the CAPEX entry barrier will also lower the TCO. Subsidies will therefore help the business case for clean tractors and favour their adoption. CAPEX subsidy programs or tax rebates should be directed exclusively to large fleets (or aggregation of smaller fleets in the same geographical areas) to encourage economies of scales across the value chain. In the French context, allowing for enhanced amortisation ("*suramortissement*"), as it is possible for CNG trucks, could also help the business case of tractors.

Reducing the fuel costs, which account for 23.5% of the TCO, is also critical. Enabling the access to low-cost renewable electricity, partial exemptions of grid fees (TURPE in France), taxes and levies (such as the CSPE in France) and allowing a level playing field for flexibility services provided by electrolysers and CEV tractors will help to keep the fuel costs low and therefore enable a better business case.

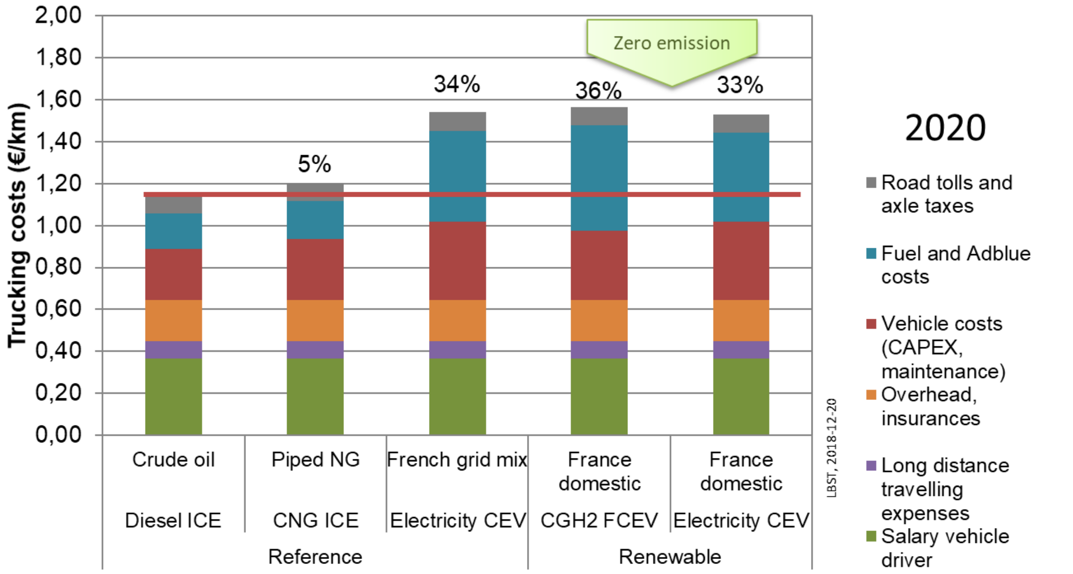


Figure 56: 2020 TCO comparison with percentage increase from reference

Simultaneously, as final demand builds up, infrastructure deployment will need to be de-risked and the economics improved by specific measures. For example, access to stacked revenues from energy, energy service and carbon markets could be regarded as an important element toward achieving infrastructure investment bankability in the short term, while being entirely in line with the long-term vision of the decarbonising the transport sector. Significant infrastructure investment will have to take place to supply end applications with hydrogen or electricity produced from renewables.

This is the case across the entire supply chain (equipment manufacturers, infrastructure operators, vehicle manufacturers, etc.). The chart in Figure 57 summarises the key challenges facing the FCEV industry at every step of the value chain and proposes a set of policy measures to overcome them.

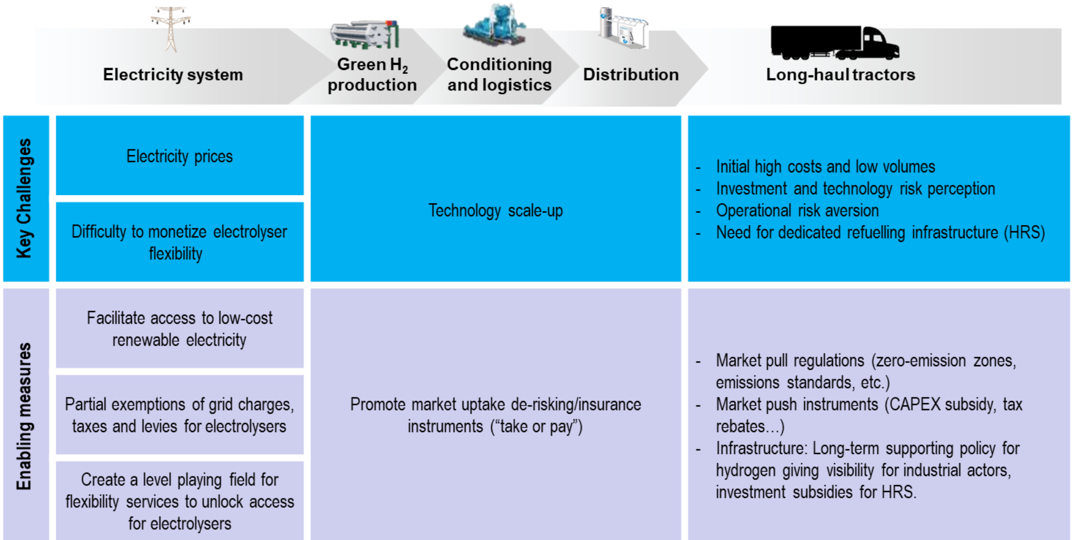


Figure 57: Key challenges vs possible enabling measures for FCEV tractors

Ensure high renewable energy targets and additionality. As both pathways will involve a significant additional amount of electricity consumed, it is imperative that the electricity mix of France remains low-carbon and, to a certain extent, renewable to achieve low WtW GHG emissions.

Specific long-term recommendations

In the long-term, measures covering the initial cost difference with incumbent technologies will no longer be as **the vehicle purchase costs will have converged towards conventional technologies.**

In 2030, the TCO of the renewable CGH2 & CEV pathways will still be 10-15% higher than conventional technologies. Accounting for positive or negative externalities (CO2, health, noise, etc.) will be needed to bring all technologies on par with diesel with **measures such as CO2 taxes, energy taxes, etc. will be necessary.** Another option would be the banning of diesel or ICE trucks on French roads.

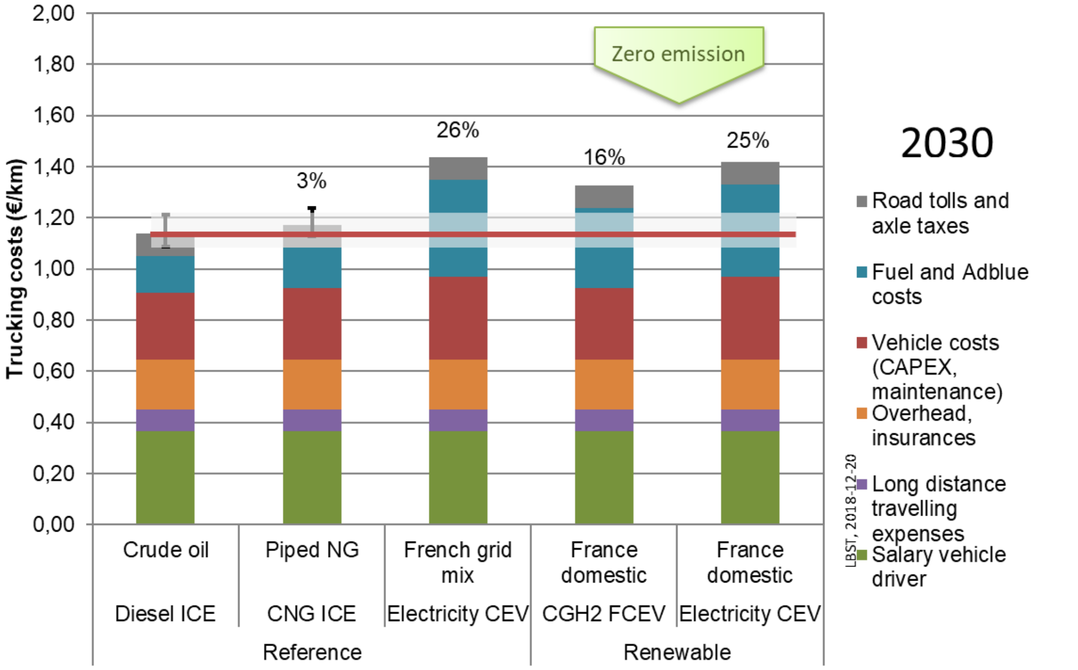


Figure 58: 2030 TCO comparison with percentage increase from reference

ACRONYMS

AFID	Alternative Fuel Infrastructure Directive
BEV	Battery-Electric Vehicle
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CEPCI	Chemical Engineering Plant Cost Index
CEV	Catenary-Electric Vehicle
CGH_2	Compressed Gaseous Hydrogen
CHP	Combined heat and power
CNG	Compressed natural gas
CO	Carbon Monoxide
CO_{2eq}	Carbon Dioxide Equivalents
CSPE	Contribution au Service Public de l'Electricité
DAC	Direct air capture
EC	European Commission
EGR	Exhaust Gas Recirculation
EPR	European pressurized reactor
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicle
FC	Fuel Cell
FCEV	Fuel Cell-Electric Vehicle
FR	France
FT	Fischer-Tropsch
GDP	Gross domestic product
GHG	Greenhouse Gas
GVW	Gross Vehicle Weight
GW	Gigawatt (1 GW = 1000 MW)
H_2	Hydrogen
HDV	Heavy-Duty Vehicle
HHV	Higher heating value
ICE	Internal Combustion Engine
LBST	Ludwig-Bölkow-Systemtechnik
LCA	Life-Cycle Assessment
LDV	Light Duty Vehicle
LHV	Lower heating value
LNG	Liquefied natural gas
M€	Million Euro(s)
MJ	Megajoule (3.6 MJ/kWh)
MS	European Union Member State
Mt	Million (Mega) ton (1 Mt = 1,000,000 tons)
MW	Megawatt (1 MW = 1000 kW)
MWh	Megawatt-hour (1 MWh = 1 MW x 1 hour = 1000 kWh)
NOx	Nitrogen Oxides

OEM	Original Equipment Manufacturer
PEM	Proton exchange membrane
PHEV	Plug-in Hybrid Electric Vehicle
PM	Particulate Matter
PN	Particulate Number
ppm	parts per million
$PtCH_4$	Power-to-Methane
PtH_2	Power-to-Hydrogen
PtL	Power-to-Liquids
RED	Renewable Energy Directive
REEV	Range-Extender Electric Vehicle
t	metric tonne
TCO	Total Cost of Ownership
TSO	Transmission System Operator (of an electric grid or a gas grid)
TtW	Tank-to-Wheel
TURPE	Tarif d'Utilisation des Réseaux Publics d'Électricité
TWh	Terawatt hour
VETCO	Vehicle Energy Calculation Tool
WHSC	World Harmonized Stationary Cycle
WHTC	World Harmonized Transient Cycle
WtT	Well-to-Tank
WtW	Well-to-Wheel (road vehicle)
yr	Year

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About

Ludwig-Bölkow-Systemtechnik GmbH (LBST) has been active in providing expertise on energy, mobility and the environment to international customers for more than 35 years, supporting international clients from industry, finance, politics, and non-governmental organisations in strategy, feasibility and market assessments. A key common denominator of all activities is the rigorous system approach, making sure all relevant elements of a tightly networked system are taken into account, providing our clients with a comprehensive and informed basis for their decisions. Typical LBST activities from our service portfolio include techno-economic analyses and modelling of energy and emission scenarios as well as detailed work on the associated regulatory frameworks. LBST provides deep down technological and scientific expertise at the same time as developing and analysing energy-related business cases and policy requirements, enabling it to lead discussions with all stakeholders at eye-level.

Hinicio is a Brussels-based strategy consulting firm based in Brussels, Paris, Bogota, Buenos Aires and Shanghai focused on sustainable energy and transport. Our fields of expertise cover renewable energies, energy storage, energy efficiency, and sustainable mobility. Since its creation in 2007, Hinicio has been developing an extended competence centre on hydrogen and fuel cells, assisting clients across the value chain in addressing all of the complex aspects and questions related to the deployment of a hydrogen-based energy system: technology, economics and finance, markets, policy and regulation, public acceptance, etc.. Hinicio's service approach is centred on four competence areas: Strategy, Investments, Public policies, and Innovation projects.

LBST and Hinicio together have successfully demonstrated their professional partnership through the delivery over 30 joint assignments in more than 10 years for a wide range of international companies and European institutions. They are both well versed in European transport and energy policy, having jointly advised the European Parliament ITRE Committee from 2008 to 2013 on energy and climate change issues. Additionally, LBST is a scientific advisor to the German Ministry of Transport for the national Mobility and Fuel Strategy and has supported the Dutch Ministry for Transport on the EU's Hydrogen Infrastructure for Transport project.

ANNEX

A1 RADIOACTIVE WASTE

A1.1 Well-to-tank

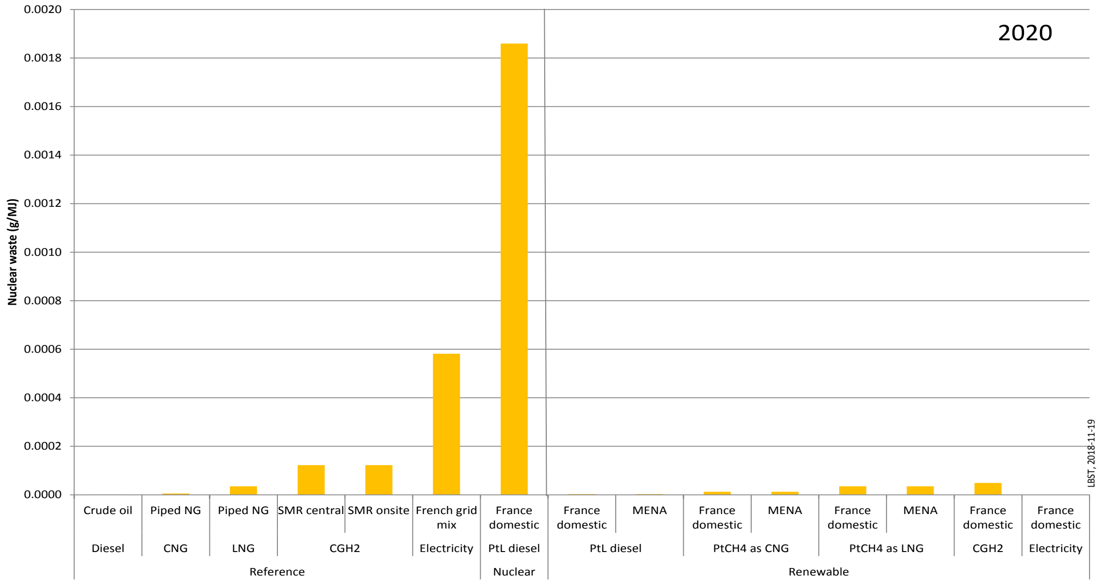

Figure 59: Radioactive waste from supply of transportation fuels (2020)

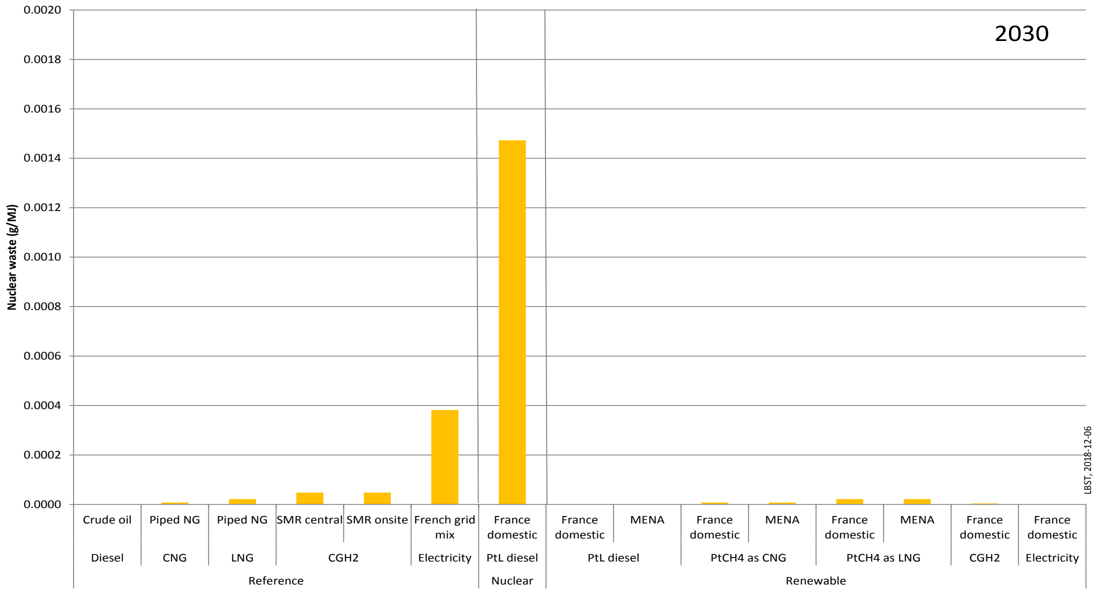

Figure 60: Radioactive waste from supply of transportation fuels (2030)

A1.2 Well-to-wheel

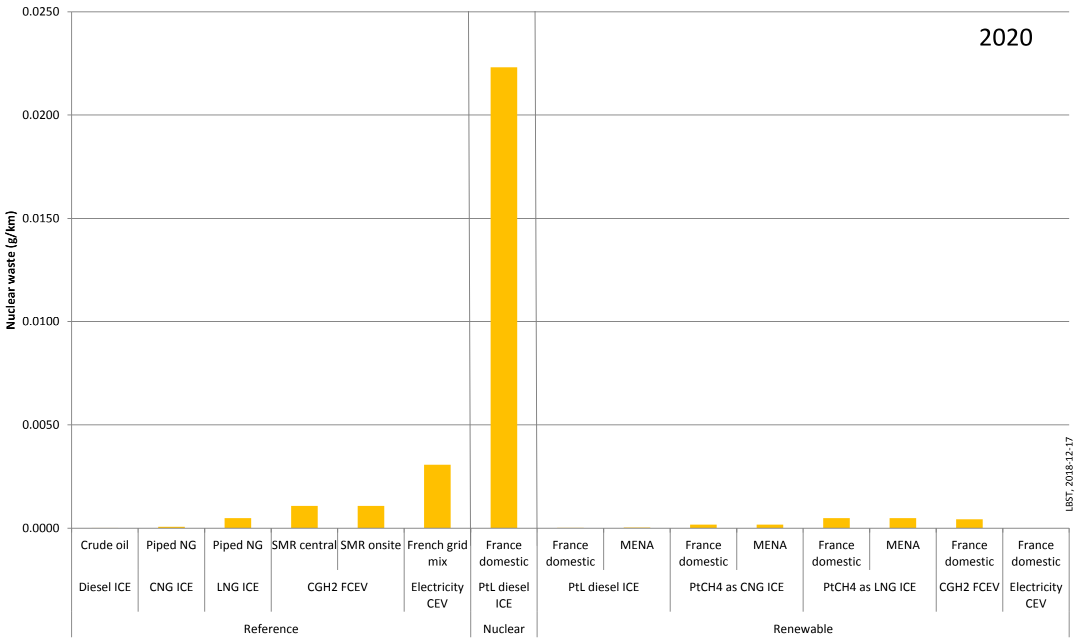

Figure 61: Radioactive waste well-to-wheel (2020)

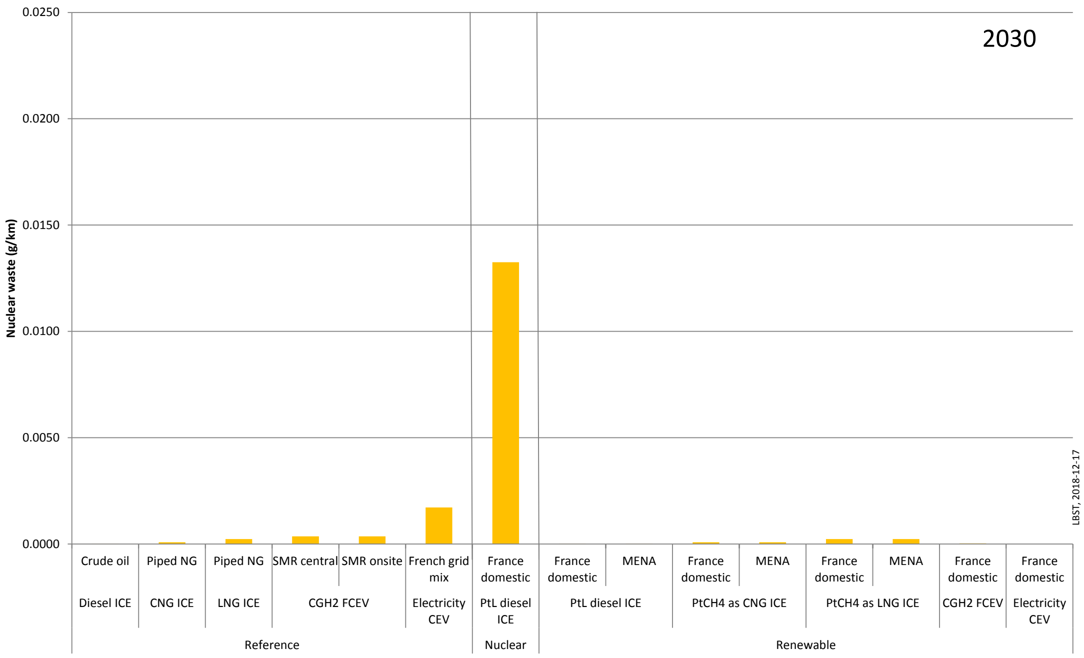

Figure 62: Radioactive waste well-to-wheel (2030)

A2 History and sensitivity of diesel consumption tank-to-wheel

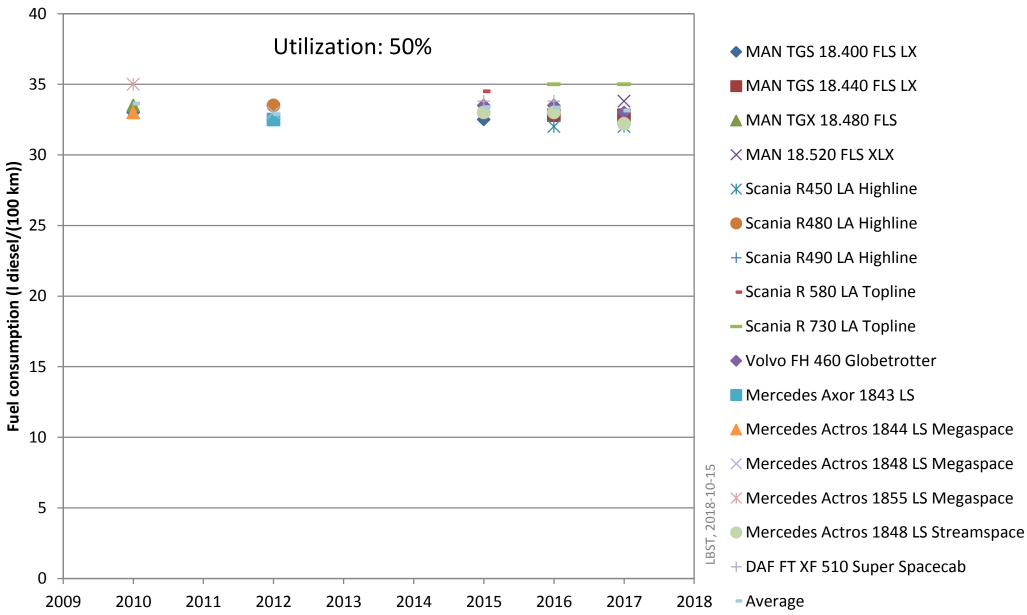

Figure 63: Development of real world fuel consumption of tractor truck in the last years for a payload utilization of 50%

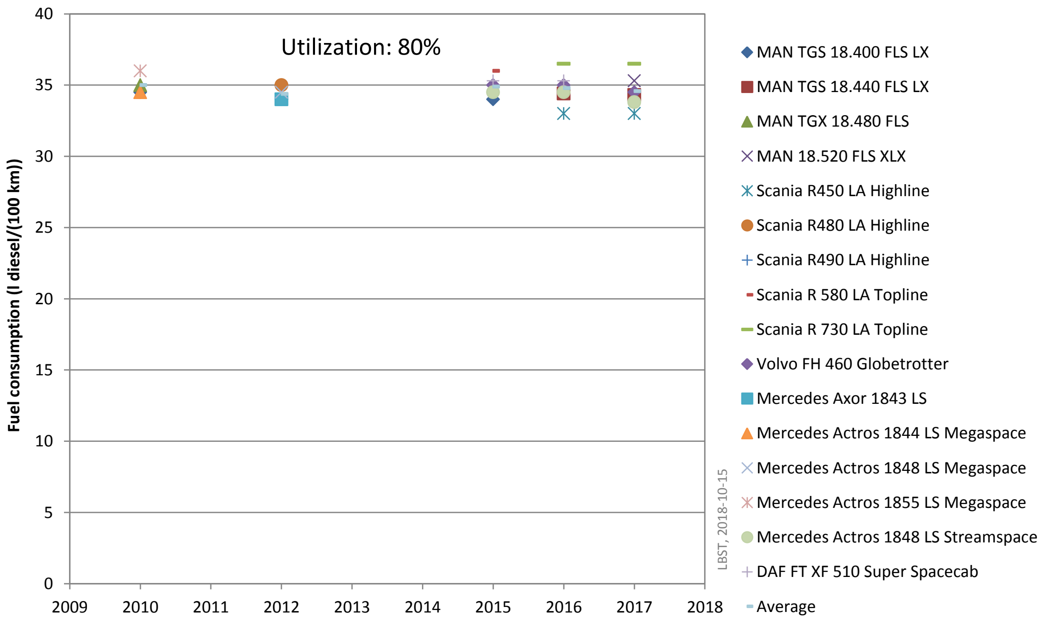

Figure 64: Development of real world fuel consumption of tractor truck in the last years for a payload utilization of 80%