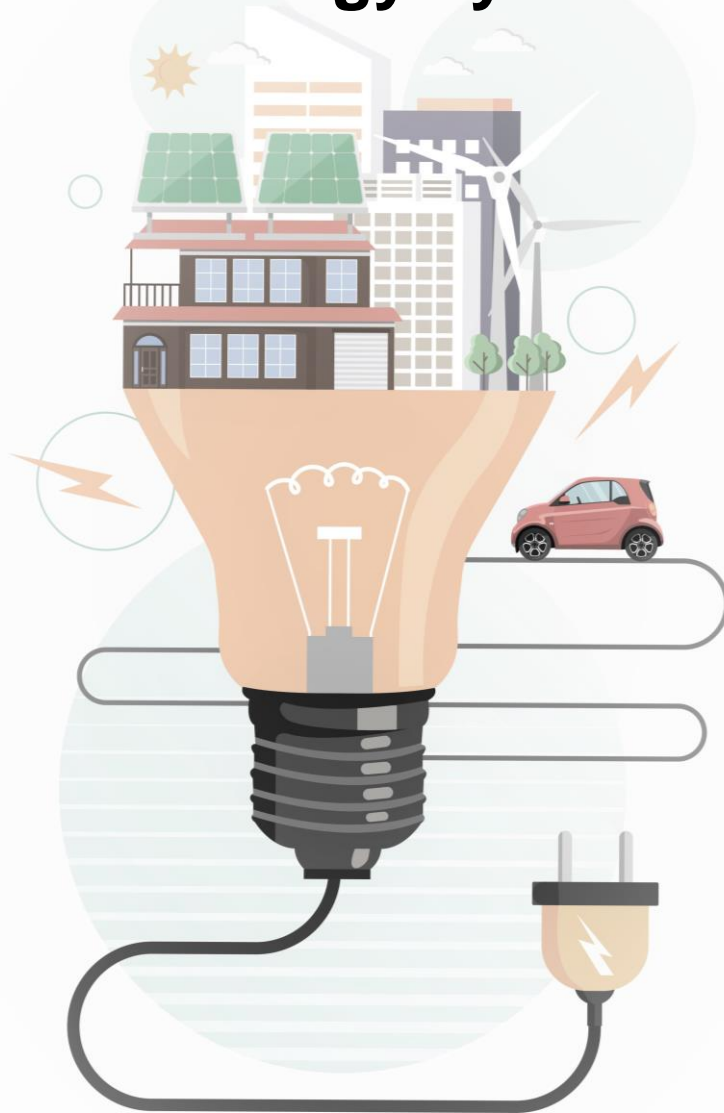




ASSET Study on **Sectoral integration: long-term perspective in the EU energy system**



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About ASSET

ASSET (Advanced System Studies for Energy Transition) is an EU funded project, which aims at providing studies in support to EU policymaking, including for research and innovation. Topics of the studies will include aspects such as consumers, demand-response, smart meters, smart grids, storage, etc., not only in terms of technologies but also in terms of regulations, market design and business models. Connections with other networks such as gas (e.g. security of supply) and heat (e.g. district heating, heating and cooling) as well as synergies between these networks are among the topics to study. The rest of the effort will deal with heating and cooling, energy efficiency in houses, buildings and cities and associated smart energy systems, as well as use of biomass for energy applications, etc. Foresight of the EU energy system at horizons 2030, 2050 can also be of interests.

The ASSET project will run for 36 months (2017-2019) and is implemented by a Consortium led by Tractebel with Ecofys and E3-Modelling as partners.

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Executive summary

Within the Paris Agreement, the European Union (EU) has committed to limit greenhouse gases (GHG) emissions to levels as low as needed to stay well below a 2°C rise in average global temperature compared to pre-industrial levels. Global emissions must reduce radically to achieve this goal. Within a world effort-sharing allocation, it is likely that OECD countries will need to limit energy-related emissions at a level close to zero shortly after 2050.

The EU is close to full adoption of an Energy Union policy package that aims at achieving ambitious targets for GHG emission reductions, renewables and energy efficiency, in 2030. Mostly sectoral policy measures (efficiency policies, standards, renewables support, including biofuels), as well as carbon pricing within the ETS, acting as the main price signal for the sectors subject to ETS obligations, are the drivers of the transition. The 2030 targets have been defined by the EU to be compatible with the 2050 emissions reductions targets that are part of the EU's pledges for the long term.

This study analyses the importance of sectoral integration to achieve the long-term clean energy transition, to achieve the emission reduction pledges for 2050, and furthermore to reach close to zero CO₂ emissions in the energy system after 2050 in the EU. Sectoral integration involves combined actions towards low carbon transition in more than one sector, aiming at exploiting synergies between them.

The Energy Union policy and legal initiatives adopted over the past two years mostly focus on sectoral measures: measures for energy efficiency for the buildings sector, car standards and other measures for low emissions mobility, promotion of best techniques in industry and facilitation of renewables in various sectors. The ETS is a measure, which is multi-sectoral, as is the energy efficiency obligation that is a crucial element of the Energy Efficiency Directive. The main sectoral integration mechanism created by the proposed measures is the increase in the use of electricity in transport and heating and this, while power generation decarbonises, leads to emissions reductions, as well as, gains in energy efficiency. The development of advanced biofuels also requires sectoral integration as the profound reorganisation is needed in the refining sector to provide such fuels for the transport sector, as well as profound beyond the energy sector in the agricultural sector.

The scenario quantifications that underpinned the Energy Union initiatives for 2030 (using the PRIMES energy systems model) show that there are significant remaining emissions primarily in mobility, but also in the domestic (residential, services and agriculture) and industrial sectors in 2050, which are difficult to abate fully. It might be necessary to enlarge the sectoral measures and enhance sectoral integration, to eliminate the remaining emissions. Enhancing sectoral integration without heavily influencing consumption patterns implies going beyond the role of electricity as a clean energy carrier, by considering inclusion of hydrogen in various roles - be it intermediate (as feedstock for the production of other energy carriers) or as of direct use - in the energy system under transition.

Hydrogen scenarios definition

Hydrogen is used today in industry as a feedstock, for non-energy purposes, mostly in the chemical and petrochemical sectors. The future role of hydrogen could be far broader and may be fundamental in the energy system transition.

This study explores three stylized strategies and a balanced pathway for sectoral integration based on hydrogen, going beyond the main decarbonisation used to support the Energy Union proposals. The study focuses first on three stylised strategies that are defined as follows:

- (A) Hydrogen as a carbon-free energy carrier in all consumption sectors, and secondarily as a provider of electricity storage
- (B) Hydrogen as a feedstock for the production of carbon-free gas and liquid hydrocarbons, and as a provider of electricity storage
- (C) Hydrogen serving mainly as versatile power storage to support electricity acting as the main carbon-free carrier in the energy consumption sectors.

All the strategies above place a central role to hydrogen, but each one emphasises on one particular pathway for using hydrogen.

All three strategies require the production of hydrogen from carbon-free electricity produced through electrolysis, and then to process hydrogen and CO₂ through additional steps, which are strategy specific. The production of hydrogen from natural gas steam methane reformer is not compatible with the decarbonisation aims unless combined with CCS technologies for the permanent storage of CO₂ emissions. However, the value chain of steam reforming with CCS is likely to be significantly less competitive than an electrolysis-based value chain benefitting from large economies of scale. Some of the technologies required in the stylized strategies are not yet market mature, and while there is a high potential for development, considerable uncertainties surround their future performance regarding costs, efficiency and the timing of readiness. The CO₂ used as feedstock in these strategies is mainly captured from the air, however other carbon-neutral sources could co-exist.

It is important to emphasise that the hydrogen-based sectoral integration strategy acts on top of the options included in the basic decarbonisation context. In other words, the following elements of the basic decarbonisation strategy are indispensable (otherwise the hydrogen-based strategy is not sustainable). A basic decarbonisation strategy, as envisaged in the Energy Union initiatives, includes four key elements : maximum energy efficiency for buildings, transport and the industrial sectors; high share of renewables in the energy system, particularly for power generation; electrification of mobility and stationary energy end-uses, where applicable, through battery electric vehicles and heat pumps; production of advanced biofuels, mainly for aviation and shipping purposes. These elements are the essential building blocks of a decarbonisation strategy, which should achieve the bulk of emission reductions in the energy system.

Strategy A requires the development of end-use technologies using hydrogen directly, including fuel cells in stationary and mobile energy uses, and equipment combusting hydrogen directly. Because of the widespread use of hydrogen in Strategy A, the development of a fully-fledged hydrogen distribution system is necessary.

Strategy B requires the development of power-to-gas and power-to-liquid technologies to substitute the remaining fossil fuels in the long-term.

In both strategies A and B, hydrogen and clean hydrocarbons are also providing power storage services.

Strategy C gives priority to maximum electrification in all sectors and uses hydrogen mainly for power storage.

The three strategies are contrasted to each other to help understand the respective pros and cons of different hydrogen applications.

Based on the assessment of the three stylized strategies, the study quantified a **balanced sectoral integration scenario** that combines elements of all three strategies. The balanced scenario includes the development of hydrogen use as an end-use fuel, a feedstock and a power storage option, in specific market segments where hydrogen can achieve a competitive advantage in the future. The balanced scenario achieves deeper emissions reductions in the energy sector by 2050 than in the basic

decarbonisation scenario, as by assumption it includes a strong techno-economic development of hydrogen-related technologies.

Finally, the study also quantified a sensitivity analysis on the balanced scenario assuming less optimistic development of hydrogen technology costs.

The main lessons from the analysis

Key technologies and business models

Following a bottom-up technical approach, the study provides an overview of different hydrogen-related and power-to hydrogen technologies and assesses the market potential for carbon-free hydrogen. The analysis identifies market and non-market barriers to deploy carbon-free hydrogen for different applications successfully. The electricity price is among the key factors that will affect the production costs of hydrogen. On the other hand, the availability of hydrogen for the power system allows considerable smoothing of the load variations thanks to the chemical storage services enabled by hydrogen and hence allows exploiting the renewable resources at maximum, without curtailment. The resulting system can further benefit from economies of scale both in power generation and in electrolysis as the renewable sources may diversify to minimise variability. The analysis confirms that in the future the power system can offer competitive prices, even slightly lower than in the basic decarbonisation scenario, despite the considerable increase in the volume of electricity generated.

Regarding deployment across the sectors, the study looks first at mobility. By comparing the technical options and the potentials to decarbonise mobility through hydrogen fuel-cells and battery-based electricity, the analysis considers that there will be market segments for both technological options to succeed depending on their relative competitiveness and strengths in each market segment. For instance, the dominance of electric vehicles in all road transport segments is hindered by range limitations that limit the use of batteries for long-distant trips.

The study also focuses on the use of hydrogen in heavy industry for energy purposes (combustion), beyond the non-energy uses where hydrogen currently has an established market. In high-temperature applications in industry, fuel cells are not appropriate but instead direct injection of hydrogen in furnaces, as in the iron- and steel-making direct injection technologies is a valid use of hydrogen both from a technical and economic perspective in the context of an emission reductions strategy.

Furthermore, in low- and medium-enthalpy uses of heat in industry, fuel cells are also applicable, and they may compete against electric heat pumps in the future if the former becomes less expensive. Even though significant advancements in heat pumps are possible in the future, there still exist low enthalpy uses in industry that is technically difficult to supply solely by heat pumps. Similarly, fuel cells and heat pumps compete in the buildings sector, where the small scales favour the latter. A fuel cell application in buildings is expensive and requires complex management, as well as heat or electricity storage. Therefore, the heat pumps have a competitive advantage in this sector.

In case of large-scale, direct use of hydrogen in the residential and services sectors and industry, a fully-fledged distribution system would have to develop in the long-term. Adaptation of existing natural gas distribution infrastructure is technically possible, but the business undertaking of such enormous infrastructure investment is difficult.

The use of hydrogen to absorb excess renewable electricity production in the power sector and thus penetrate in specific markets in the same geographic area is a concrete business case, which is feasible for the private sector to undertake in the early stages of the transition. The study has identified such cases to provide information on key regions that today already have excess electricity generation.

Electrolysis is the key technology to produce carbon-free hydrogen and is necessary for all strategies. Alkaline water electrolysis and the rapidly improving PEM (proton exchange membrane) electrolyzers are at a sufficient technology readiness level (TRL). Very significant cost reductions are possible if electrolyzers develop at a large scale. The SOEC (solid oxide electrolyser cell) technology is currently at a low TRL but may become a promising technology in the chain producing liquid hydrocarbons from hydrogen and CO₂ in the future.

Storage of hydrogen at a large-scale, for example in natural caverns, will have to accompany the development of large-scale distribution systems in the context of a strategy where hydrogen becomes a universal energy carrier. Smaller scale storage systems, for example, pressurised tanks and tubes storing liquefied hydrogen, are appropriate for small- and medium- scale applications, such as in industrial areas and in large-scale stations refuelling hydrogen. Small-scale storage systems could develop in the early stages of the transition to facilitate the development of small and medium scale specific uses of hydrogen, especially in the transport sector and in industry.

Two possible business models exist for hydrogen: decentralised hydrogen production close to end-users or centralised hydrogen production. For the transition period and in view of using hydrogen as an energy carrier, decentralised hydrogen production is a valid option for private investment. However, it is currently uncertain whether electrolysis at the scale of refuelling stations or in industrial areas is more economic than the distribution of hydrogen to the refuelling stations using tanks or tubes. However, the centralised option would probably be the preferred option for the production of hydrogen in the long-term because the industry expects large economies of scale for large-scale electrolysis.

Any business model - to be successful in the long term - requires the entire chain of users, producers and infrastructure to be available in a timely manner. In reality, market coordination failures may occur in such circumstances. To this respect, decentralised production in the initial expansion phase is less vulnerable. But for the development at hydrogen availability scales as envisaged in the strategies, successful market coordination is essential. Coordination applies to infrastructure developers, technology and research providers, upstream hydrogen producers and end-use consumers. As the actors have different aspirations, long-term anticipation and regulatory certainty are of utmost importance for market coordination.

Pros and cons of the respective strategies

Strategy A explores the use of hydrogen as an energy carrier for the entire system and in most end-use sectors directly. In road transport, the use of hydrogen may eliminate range limitations that electric powertrains currently have and has an easier application than electricity to several of the transport modes. However, the strategy requires the development of new hydrogen transport and distribution infrastructure for all sectors, which would replace the gas system. The implementation may be difficult. However, some recent studies envisage ways of accommodating the gas grids effectively. Both centralised and decentralised production of hydrogen can co-exist as valid business models in this context. Centralised production in large electrolyzers can produce hydrogen at competitive prices to feed the distribution infrastructure of pipelines. Smaller-scale decentralised production in refuelling stations can co-exist. The strategy A also requires the development of large-scale hydrogen storage facilities. In an intermediate phase, the hydrogen could be blended (up to 15%) in the gas grid to take advantage of the natural gas infrastructure and ensure a more gradual transition. However, in the long-term, the grid should be adapted to hydrogen. The end-use equipment has to be converted for hydrogen burning (for mixtures beyond the 15% blending limit), while industry needs to invest in furnace technologies using hydrogen directly. In the mobility sector and power-heat cogeneration applications, the key

uncertainty is the cost reduction and development of fuel cells. Market coordination is essential to allow such a scenario to develop, as demand, production and infrastructure need to develop simultaneously. The modelling shows that Strategy A implies significant increases in the volume of electricity generation, to produce hydrogen, but the increase is at a rather manageable scale, provided that large-scale interconnections allow access to renewable intensive sites across all of Europe. The large-scale production of hydrogen allows the provision of electricity storage services through hydrogen, which facilitates the large-scale integration of renewables in the power system. The projection assumes enhancement of access to remote areas with high renewables potential via high voltage interconnections and shows the possibility of further expanding nuclear capacity.

Strategy B, which explores the use of hydrogen as a feedstock, has the main advantage that end-use sectors do not require major changes of equipment and infrastructure beyond those envisaged in the basic decarbonisation scenario. Also, the existing refuelling infrastructure can continue to be used. However, to be carbon free, the scenario requires the development of technologies such as direct carbon capture from air, which is still far from reaching market maturity. Further, the scenario requires very high amounts of electricity to produce the clean hydrocarbons, and according to the modelling projections, producing the clean synthetic fuels at relatively high costs and with poor overall energy efficiency is inevitable. The modelling shows that electrification of transport, heat pumps and biofuels as projected in the basic decarbonisation scenario must be maintained and probably enhanced, to limit the increase in electricity demand implied by the production of the synthetic fuels. Otherwise, the huge electricity demand would bring the power system to its limits.

Strategy C explores using hydrogen mainly for power storage: while seeming initially less complex than other pathways and requiring the least increase in power generation, the strategy would require the full electrification of all end-use sectors to achieve near-zero emissions. While this can work for the domestic sector, for industry and transport it is barely possible. In industry, complete electrification is probably impossible without considerable changes in production processes. In transport, extreme solutions such as electric aviation and shipping would need to succeed or alternatively massive production of fungible biofuels will be necessary for aviation and ships. Electricity is being the single energy form for all consumers, which may cause concerns in case of lack of sufficient reliability. The power to hydrogen process for storage is the closest to market maturity and can be expected to develop without major uncertainties. The modelling shows only a modest increase in demand of electricity compared to the basic decarbonisation scenario, due to the high efficiency of the electric end-use equipment, and a reliable power system operation due to the role of hydrogen as storage.

All three stylised strategies have the merit to lead to almost full energy independence in the EU. They are all affordable regarding total energy system costs, provided that the new technologies exploit their learning potential and the infrastructure develops without market coordination failures.

Although all three stylised strategies have specific advantages and allow for the achievement of close to zero CO₂ emissions in the energy system, they also involve major uncertainties, notably around technology developments, and market coordination across actors with different aspirations. In this perspective, the current study simply outlines the likely impacts of such stylised pathways, while the study is inconclusive about the respective merits and drawbacks. Thus, the study does not recommend one of the stylised strategies but instead considers a balanced approach to approximate cost-effectiveness.

In such a balanced scenario, the aim to achieve a near full decarbonisation of the energy system implies the hydrogen-based sectoral integration combining all possible roles of hydrogen in the most promising sectors and at different proportions, . Assuming that in

the long term hydrogen technologies achieve the lowest possible costs, a balanced scenario could be one with the following characteristics:

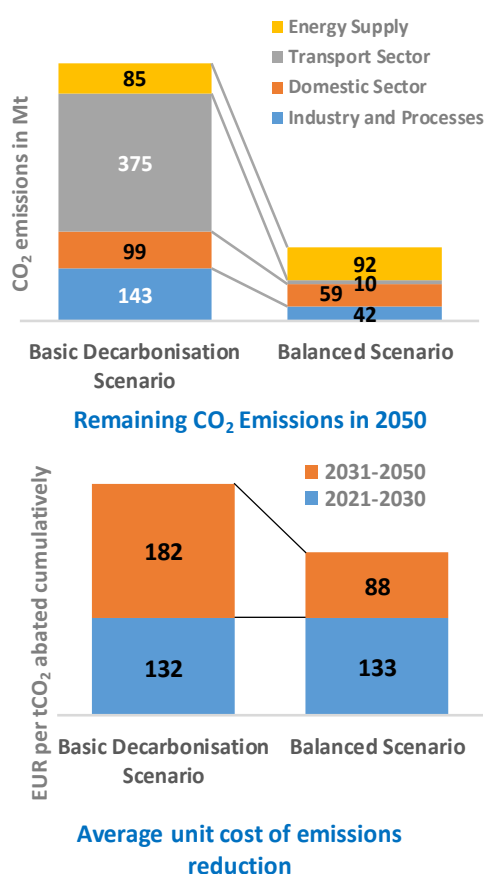
1. Mix hydrogen up to 15% in the gas distribution grids, together with amounts of bio-methane and clean methane (produced from hydrogen and CO₂ captured in the air); the share of each of the latter reaches between 15-20% in the long-term;
2. Use electrolysis-produced hydrogen to feed fuel-cell powertrains in large vehicles (trucks, buses, etc.) and long distance travelling cars (including taxis). Hydrogen refuelling can benefit from returns to scale as only fuelling hubs are required to feed the large vehicles;
3. Use hydrogen directly in high-temperature furnaces in industry, including in iron and steel, the chemical industry and other sectors;
4. Develop power-to-H₂ technologies in the power sector to provide electricity storage services at a large-scale, as needed to maximise the use of renewables, and produce hydrogen and clean methane used by consumers.

The scenario finds that at the costs assumed, fuel cell heavy-duty vehicles start penetrating the market from 2030 onwards and achieve a considerable market share by 2050. Battery-charged cars combined with fuel cell powertrains for heavy-duty and large mileage travelling vehicles succeed to drop carbon emissions in road transport close to zero by 2050. Advanced biofuels drastically reduce carbon emissions in aviation and maritime sectors by 2050. As the focus only on these sectors, the required amounts of biofuels by 2050 are reasonable and sustainable from a supply perspective.

The refuelling infrastructure for hydrogen develops only in the main road highways and in refuelling hubs, at scales that are cost-effective. The mix of hydrogen, bio-methane and clean methane in the gas distribution system allows 50% of the gas to be carbon-free by 2050. The merit is to continue using the

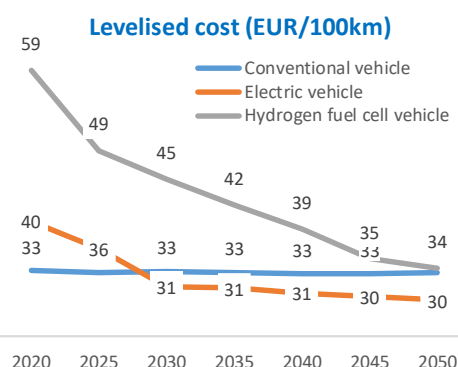
gas infrastructure and maintain the uses of gas in the domestic and industrial sectors. In buildings, the combination of the strong renovation of buildings, the widespread penetration of heat pumps and a 50% "carbon-free" gas reduce the remaining emissions very significantly. Similar carbon emissions reduction takes place in the low-enthalpy heat uses in industry, thanks to the combination of efficient energy saving technologies, heat pumps and the 50% carbon-free gas. Adding the direct uses of hydrogen in high-temperature applications implies that the industrial sector can also reach very low emission levels.

The balanced scenario has the merit of limiting the use of technologies and infrastructures that seem difficult to develop from today's perspective. The balanced scenario achieves a 96% reduction in CO₂ emissions from the energy sector (including industrial processes) in 2050 (relative to 1990), which is 12 percentage points more than in the basic decarbonisation scenario (-84% CO₂ in 2050). The user prices of energy and the overall

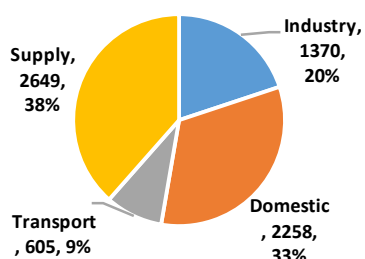


energy costs from a consumers' perspective remain affordable and close to the basic decarbonisation scenario. The average annual total energy system costs in the period 2030-2050 are 3.5% lower. The balanced scenario abates CO₂ at an average cost of €88/t CO₂ (cumulatively in the period 2030-2050), which is less than half of the cost in the basic decarbonisation scenario (€182/tCO₂ abated). This remarkable performance of the balanced scenario owes to the new technology assumptions for the technologies that allow multiple roles of hydrogen as a sectoral integration means and its particular role in the transport sector.

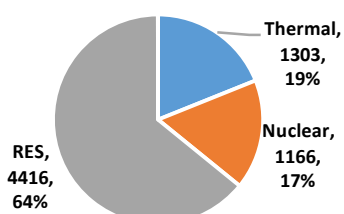
Despite reaching close to zero emissions by 2050, total costs in transport are lower in the balanced scenario than in the basic decarbonisation scenario, which projects emissions to be in 2050 only 60% below 1990 levels. Hydrogen utilisation in specific market segments in transport where it can achieve the lowest possible cost, in particular, the heavy duty or the large mileage travelling vehicles, provide cost reduction benefits. In addition, this reduces the total amount of biofuels allows utilisation of the biofuels at quite reasonable fuel costs specifically in aviation. All transport sectors optimise costs, including the private cars dominated by battery-based powertrains. The cost reductions in the transport sector depend on assumptions. A cost reduction of the fuel cell stack from roughly €300/kW today down to €44/kW in 2050, and a similar reduction of battery costs from roughly €400/kWh today down to €100/kW by 2050 enable the cost reductions. Regarding the levelized cost of an average medium-size car, the scenario assumes that the EVs are the cheapest in 2050 and that the fuel cells reach cost parity with conventional internal combustion cars.



Electricity Consumption in the Balanced Scenario in 2050 (GWh)



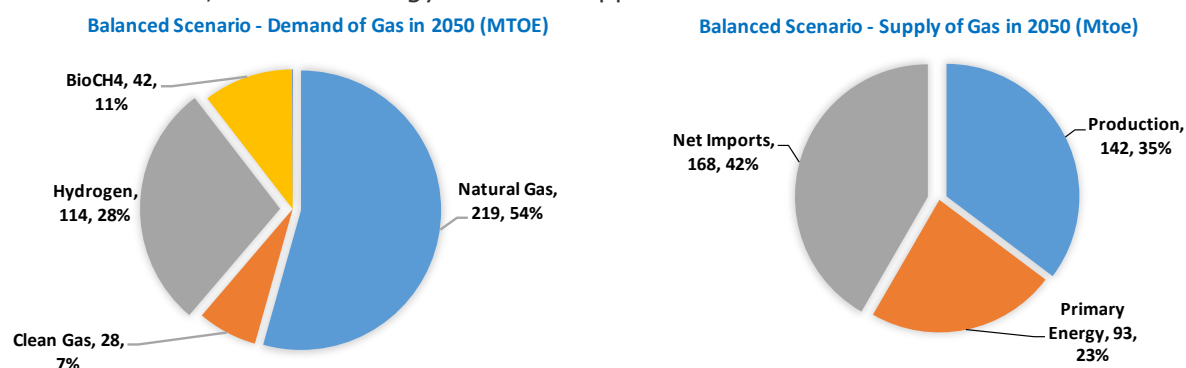
Electricity Production in the Balanced Scenario in 2050 (GWh)



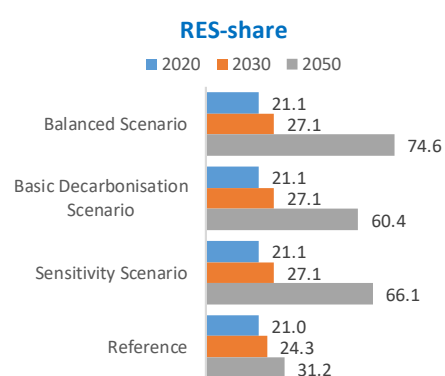
The part of the power sector producing hydrogen and clean fuel reaches 29% of total power generation in the balanced scenario by 2050. It is remarkable that despite the significant increase in the volume of power generation in the balanced scenario (34% above the basic decarbonisation scenario in 2050 and 69% above the reference scenario), the average EU electricity prices do not increase, but rather presents a marginal drop. This owes to the market integration and the interconnected system allowing access to remotely located renewables and an effective sharing of balancing resources. In this respect, the hydrogen-based storage of electricity has a considerable contribution to smooth the load curves and to shift energy from renewable electricity to times periods when renewables are in deficit. The maximisation of renewables' capacity factors, enabled by hydrogen, helps lowering electricity costs. In this way, the renewables increase by 36% in the balanced scenario, compared to the basic decarbonisation scenario in 2050. The RES share in power generation is slightly above 70% by 2050, but

power generation from RES needs to increase by 1300 TWh in the balanced scenario by 2050 compared to the basic decarbonisation scenario.

Hydrogen, clean gas and bio-methane cover almost half of total consumption of gaseous fuels in the balanced scenario by 2050. The natural gas is mainly necessary for power generation and industrial applications; in both cases, the respective plants are equipped with CCS technologies. Only 42% of total gaseous fuels are imported in 2050, the rest produced domestically using hydrogen and electricity. Given also that the largest part of the liquid fuels remaining in use by 2050 is fungible advanced biofuels, the overall import dependency is only 27% in the balanced scenario by 2050, significantly down from 56% in 2015 and lower than in the basic decarbonisation scenario (36% in 2050). The use of oil products decreases by 80% in the balanced scenario by 2050 compared to 2015 levels, and non-energy industrial applications use the 102 out of the 117 Mtoe



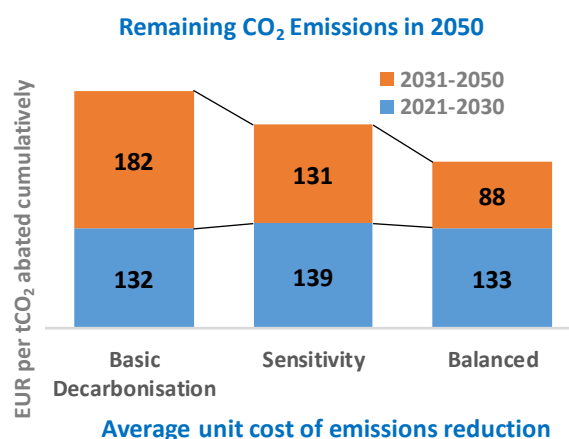
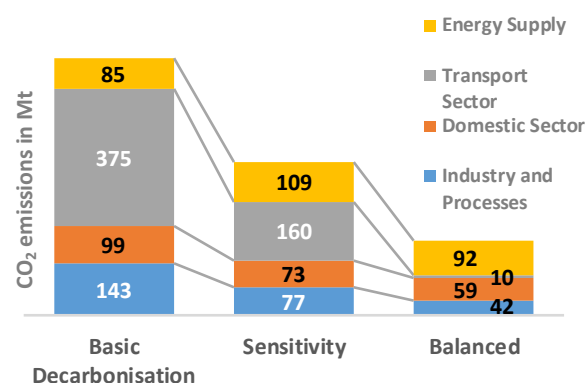
oil products remaining in 2050. The imports of natural gas are 38% below 2015 levels in 2050.



2050 in the balanced scenario, 14 percentage points above its level in the basic decarbonisation scenario. Despite the production of significant amounts of biofuels, biomass imports are only 14Mtoe in 2050, 3.3 Mtoe up from the projection for 2020. The imports of biomass in the balanced scenario are 5 Mtoe lower than in the basic decarbonisation scenario, in 2050. The domestic production of biofuels meets sustainability criteria regarding feedstock and land-use.

A sensitivity analysis scenario which assumes a less optimistic development of hydrogen technology costs shows that

The renewables cover the largest part of the incremental energy in the balanced scenario. In consequence, the RES-share approaches 75% in



emissions reductions close to 90% in 2050 are possible at relatively affordable costs; the average annual total energy system costs in the period 2030-2050 are 1.9% higher than in the case of the balanced scenario. If hydrogen technologies would be more expensive in the long term, as in the sensitivity analysis, the energy system costs would still be lower in the balanced scenario compared to the basic decarbonisation scenario, but only by 1.6%. The average CO₂ abatement cost would be €131/t CO₂ in the sensitivity scenario (cumulatively in the period 2031-2050). The sensitivity scenario show lower penetration of hydrogen in the end-uses due to the higher costs of fuel cells. The total amount of hydrogen used in the EU either as a fuel or as feedstock for the production of synthetic methane in this scenario is 100 Mtoe, down from 150 Mtoe in the balanced one.

If hydrogen-related technologies (on both the demand and supply sides) reduce significantly in costs compared to today, they can become a key technology to help reduce emissions beyond the levels achieved in the basic decarbonisation scenario and at affordable costs.

The balanced scenario benefits from the availability of hydrogen technology options and the reduced costs of fuel cells, which by assumption were not available in the context of the basic decarbonisation scenario. In this sense, the two scenarios are not fully comparable regarding their total cost performance. The merit of the sectoral integration enabled by hydrogen is that it enables stronger abatement and lower costs, just because this option has not been considered in the basic decarbonisation scenario.

The sectoral integration enabled by the Power-to-H₂ and H₂-to-gas technologies allow the carbon-free use of hydrogen in final energy consumption in those applications that cannot be directly supplied with renewable energy or direct electricity. To achieve the expected cost reductions in the technologies, large-scale investments and effective market coordination of different actors are necessary.

In order to achieve overall GHG emission reductions beyond the 80% target, it is paramount that such technologies develop in a timely manner. The strategy to follow must be decided most probably before 2030. The high R&D developments required for the successful achievement of zero emissions need clear signals to allow positive anticipation by the research community and the investors. To achieve close to zero emissions shortly after 2050, modifications of the energy system must be well under way a decade before. In this context, a review of technological developments must occur within probably the next 10 years to progress towards finding a decisive reply to the question "which strategy to follow?". The investment requirements are such that it is deemed impossible to be able to maintain development of certain options in parallel over an extended period. In the long term, a few of the technologies will dominate as it is unlikely that all competing technologies will achieve the required economies of scale. Choices among the technologies and therefore strategies are necessary to be decided at some point in the future.

As a next step, not addressed in this study, the assessment of suitable energy policy instruments should have priority. The question is which instruments would enable emergence and widespread adoption of the technologies, and facilitate market coordination more effectively. Further steps are also required to assess the sectoral integration strategies from a financing perspective and evaluate the impacts on industry, exports and employment in the EU. Further analysis of the possible integration of clean hydrogen in the industrial processes and produced materials also requires more in-depth insights.

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Introduction

Both the Energy Union strategy and the SET plan for innovation primarily focus on sectors, such as efficiency in buildings, sustainable transport, energy market integration, renewables, etc. At the same time, the strategy recognises energy system integration as an enabler of transformations towards deep decarbonisation. While the advanced technologies and the supporting measures operate at a sectoral level, the optimum transformation of the energy system requires moving along integrated pathways.

An already agreed option of sectoral integration is the role of electricity as a carrier of emissions reductions in transport and heat uses combined with deep decarbonisation of power generation. The sectoral integration enabled by electricity brings also substantial energy efficiency gains. The electrification, however, may not be technically able to cover 100% of all uses of fossil fuels in the energy system and at the same time, carbon-free substitutes such as biofuels do not have sufficient feedstock resources to cover the residual uses of fossil fuels.

The decarbonisation roadmaps developed so far have shown persistence in the long-term of emissions from fossil fuel combustion in heating and industrial uses mainly due to the use of natural gas and in the transport sector due to the use of mineral oil liquid fuels in certain transport means. Therefore, a strategy towards full decarbonisation of the energy system –i.e. going beyond the 80% emission reduction in 2050–, as required by the climate strategy in the long term, consistent with the Paris Agreement ambition, is not feasible unless emissions-free carriers develop based on a sectoral integration strategy. Emissions-free methane and liquid hydrocarbons, as well as emissions-free hydrogen are probably necessary to develop. Their production in the power sector may be challenging regarding resources and grids. They will also likely require a large increase in electricity production due to large energy conversion losses and, in the case of wide-spread use of hydrogen, would require a dedicated distribution network. However, it is widely recognised that the production of such carriers can also deliver electricity storage services in the power sector (known as chemical storage) thus allowing maximum possible use of variable renewables in power generation.

Hydrogen plays a central role, directly or indirectly, in the integration of sectors. However, there exist alternative pathways regarding hydrogen, which deserve economic and feasibility assessment. In a stylised manner, hydrogen may serve for storage of electricity a feedstock to produce emissions-free gas and liquid hydrocarbons, and as an energy carrier serving final stationary and mobile energy uses directly. Therefore, the power to hydrogen, gas or liquids technologies, are key for an adequate sectoral integration in the context of deep decarbonisation of the energy system.

Objective of the study

The objective of this study is to identify the impact of sectoral integration on energy system including the cost and infrastructure requirements of the energy system, in the context of deep decarbonisation in line with the Paris Agreement. The following aspects will be analysed:

- Power to Gas, and the use of H₂ and clean gas in decarbonising the natural gas grid
- The use of carbon-free H₂ in industry (in high temperature applications in addition to its use as a feedstock in some industrial sectors)
- Linking the power and mobility sector, both via electricity and hydrogen
- Linking the power and heating sector, in buildings and industry

- Analysing strategies which allow to achieve deep decarbonisation and the enabling contribution of power-to-X technologies to produce renewable hydrogen and hydrocarbons.

Structure of the report

The study comprises two main tasks:

Task 1 consists of a mapping of the key Power-to-X technologies and an assessment of the techno economic parameters and barriers including associated costs of hydrogen production and the development of a transmission and distribution network. The task aims at improving the understanding of the potential of the various technologies and the interactions between different energy sectors, including the electricity and gas grids. The goal is to define the potentials and limitations of energy storage, serving energy needs in final energy demand and other relevant applications.

The Task consists of five subtasks: a) Linking the power and mobility sector & Usage of H₂ in transportation, b) Linking the power sector and H₂-demanding industry, c) Linking the power and heating sector, d) Energy storage and sectoral integration and e) Identifying key regions with local overproduction and excess of renewables.

Task 2 uses systems analysis and modelling to develop narratives about future impact of sectoral integration in the energy system towards 2050, in the context of the deep decarbonisation required by the Paris Agreement. To assess the potential role and contribution of power-to-X technologies and storage under different contexts, three narratives seem relevant: a) the 'hydrogen as an energy carrier' scenario, b) the 'hydrogen as feedstock' scenario and c) the 'hydrogen for power storage' scenario. Based on this analysis a balanced scenario and a sensitivity scenario to 2050 are modelled with different assumptions about the development of hydrogen related technologies and the market penetration of hydrogen.

The main results are subject to discussion in the final 'Discussion' section. The document also includes a large bibliography on the topic and ends with conclusions and recommendations.

Hydrogen roadmap TO 2050: assessment of technological and market developments

As mentioned in the introductory section, hydrogen could be present in all possible configurations of sectoral integration within a long-term strategy for deep decarbonisation of the energy system. In the sense of the integration strategy, i.e. hydrogen as an energy carrier that could serve all the end uses, the full value chain of hydrogen is as shown in Figure 1. As subsequent sections explain, alternative configurations of the sectoral integration strategies may not develop the entire value chain of hydrogen. It may be that hydrogen produced from electrolysis fed by carbon-free electricity serves as a means of storage of electricity. It may also be that hydrogen is a feedstock to produce carbon-free methane and liquid hydrocarbons to substitute the corresponding fossil fuel products in end-use consumptions. Finally, hydrogen can well be an energy carrier in all the end-use consumptions.

This section describes the main technological and market developments of hydrogen. The section also mentions key technologies that compete with hydrogen where this is relevant. The data collected on costs and technologies serve to create technology assumptions used in the modelling. Consultation on these data with stakeholders is ongoing. The data on technologies are specific to application areas, such as mobility, heating, power, industry and storage.

Hydrogen value chain and the key business models

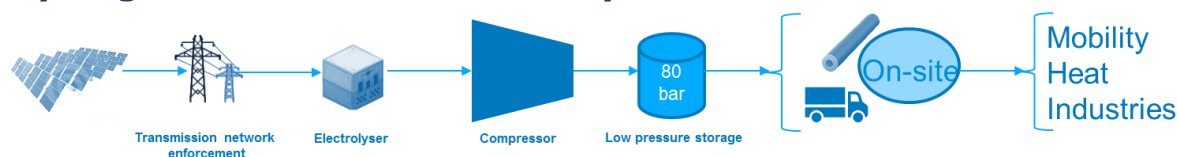


Figure 1: An illustrative scheme of a hydrogen value chain:¹

Hydrogen production

Steam methane reforming is the currently conventional technology to produce hydrogen from fossil fuels, mainly natural gas. The technology is mature and competitive but it is not carbon-free.

In a decarbonisation context, electrolysis using carbon-free electricity is the technology of preference for producing hydrogen. The cost reduction potential is very significant for electrolysis technologies.

In a deep decarbonisation context, the large use of intermittent renewables implies that excess carbon-free electricity can occur at certain times as well as shortage of carbon-free electricity at other times. Producing carbon-free hydrogen using electrolysis at times of excess of carbon-free electricity allows producing electricity from hydrogen at times of carbon-free electricity shortage. Obviously, this maximizes the use of renewables and serves as a perfect storage of electricity – known as chemical storage of electricity through electrolysis.

An electrolyser can produce hydrogen at a pressure of 30 bar. This can be further compressed to 80, 350, 700, 950 bar to reduce the size of storage needed. An 80 bar pressure is necessary for injection in the natural gas network, whereas a pressure of 350-950 bar applies for using hydrogen in transport, for example in trucks and passenger vehicles.

¹ The scheme is only exemplary for possible hydrogen value chains, others are possible and might be economically more viable.

The data collected suggest the following basic cost assumptions:

- Large-scale alkaline electrolyzers, which is currently the most wide-spread electrolyser technology, currently cost less than 500 €/kW [1] and have an electric efficiency of 55 kWh/kg H₂ (72%) [2]; the cost may drop to 350 €/kW by 2020 based on industrial estimates and further decrease in the long term significantly. The CAPEX of the electrolyzer is expected to decrease in the following years due to the increase of the cumulative produced volume of electrolyzer thanks to the increase in sale which will decrease the production costs. The energy efficiency may exceed 85% in the long term.
- More advanced electrolysis technologies are under development: proton exchange membrane – PEM and solid oxide electrolyzer cell – SOEC. The advantage of PEM versus the alkaline technology is the ability to operate efficiently under variability of electricity inputs, which facilitates the use of renewable-based electricity. Also, the PEM electrolyzers can achieve higher efficiency in the future compared to the alkaline ones and be applicable at various sizes as the dis-economies of scale – which are a problem for Alkaline electrolyzers – are rather limited (in the order of 20% in levelized output costs). The SOEC electrolyzers can reach the highest efficiency, among all technologies, if they become mature in the future. The main advantage of SOEC is the possibility to co-electrolyse hydrogen and carbon dioxide to produce syngas (mixture of hydrogen and carbon monoxide), which can further upgrade to methane and other hydrocarbons. However, the SOEC electrolyser runs at high temperature, which poses challenging engineering problems requiring solutions in future mature systems.
- Electrolysis can reach an efficiency of above 80%. As the reuse of hydrogen for electricity generation can have an efficiency of 60%, the overall efficiency of chemical storage of electricity based on hydrogen can be close to 50%. If the reuse of hydrogen takes place in fuel cells, the overall electric efficiency can be up to 60-65% (excluding possible heat uses).
- Storage of electricity based on hydrogen is versatile regarding the timeframe and, depending on the available facilities of hydrogen storage, storage of electricity can be seasonal, weekly and daily.

The CAPEX of electrolyzers will decrease in the future because of large-scale installations. Except the SOEC, all other technologies of electrolysis are currently at a high level of technology readiness. SOEC electrolyzers have a similar cost reduction potential but have additional benefits as they can produce syngas in one unit and produce hydrogen directly at different pressures.

The unit cost of hydrogen produced from electricity mainly depends on the unit cost of electricity. Maximizing the use of intermittent renewables, thanks to hydrogen storage combined with the technology learning effects imply significant reductions of unit costs of hydrogen in the future. The levelized unit cost of electricity production using mature renewables technologies can reach levels well below 50 EUR/MWh of electricity. Therefore, the unit cost of hydrogen can be well below 60-70 EUR/MWh hydrogen in the future. At a price of 35-40 EUR/MWh-natural gas, hydrogen requires a carbon price of the order of 80-100 EUR/tCO₂ to become competitive vis-à-vis natural gas.²

Using the same price range, the storage of electricity using hydrogen can reach a unit cost of 100 EUR/MWh of electricity stored. Expectations are that the battery technology at a large scale is able to reach similar levels of unit costs of electricity stored. However, the battery storage is less versatile than hydrogen-based storage of electricity regarding

² However, for a fully correct comparison the efficiency of the end-use technology would also need to be taken into account. E.g. fuel cells in mobility are more efficient than ICEs using compressed natural gas.

the timeframe of storage, but depending on the use both have advantages (see section Energy storage and sectoral integration).

As the cost of electricity is of critical importance for the cost of hydrogen, it is of great importance to place the production facility of hydrogen in areas with a supply of cheap electricity, directly or via large-scale interconnections.

The economics of electrolysis also suggest maximizing the rate of use of the facilities, which implies that it is useful to form a portfolio of carbon-free electricity featuring a base-load load profile. Therefore, combination of renewables from various sources or from different locations including via interconnections is important for reducing the unit cost of hydrogen. Dispatchable carbon-free generation, such as nuclear, can provide a base-load supply to electrolysis and ensure the achievement of largest possible economies of scale.

The analysis of business cases for electrolysis development in the private sector suggests that two critical factors need to co-exist:

1. Large-scale and base-load supply of cheap electricity
2. Demand certainty for electricity depending on demand for hydrogen to feed units producing clean fuels or distributing hydrogen and clean fuel

Hydrogen as a feedstock for synthetic hydrocarbons (concentrated industrial processes)

If hydrogen is a feedstock for the production of clean hydrocarbons, the seller of hydrocarbons requires demand certainty. If hydrogen is an energy carrier, the hydrogen seller requires demand certainty. In both cases, the simplest way to ensure a solid economics basis for the business case are back-to-back contracts between electricity supply and the seller of hydrogen or the products derived from hydrogen can. The demand for the hydrogen products or services should be guaranteed through policies e.g. such as zero emission standards for transport or supported by policy and policymakers through regulations and infrastructure construction. Regarding the electricity storage services, the purchaser of the services would usually be the systems operators or large-scale suppliers of electricity in the case of self-balancing practices. The business case will strongly depend on the arrangements and the functioning of the market for ancillary services and the balancing of electricity. It is well possible in the future to also see large-scale aggregators acting as electricity suppliers to combine intermittent renewables and storage including through hydrogen to form economically versatile supply portfolios.

All these business cases need to be concentrated and conducted at industrial scale because of the importance of the economies of scale and the base-load operation requirement. Large-scale companies are likely to invest and develop this business. As mentioned, the economic environment has to be a strong decarbonisation policy and a carbon price, implicit or explicit, featuring sufficient range and stability.

Hydrogen use for final energy consumption (decentralised, small-scale)

Small and medium scale business applications for hydrogen can coexist. They include the direct use of hydrogen in consumer's applications, e.g. for mobility, heating, or industrial purposes. A fuel cell is a device that converts the chemical energy of hydrogen into electric energy and heat. The products of the reaction are electricity and water. The fuel cell is a promising technology because of the easiness of use, the robustness and its efficiency. The applications areas are diverse and can be at various scales. However, the main issue is the capital cost of fuel cells, which is persistently high despite the research and industrial efforts over a long period in the past. Therefore, great

uncertainty surrounds the economics of fuel cells. Should the fuel cell costs experience strong learning potentials, they could present an alternative to the battery-based electrification of mobility particularly for modes such as heavy duty vehicles for which electrification is also a challenge. Under such conditions, the fuel cells could also get a large share in stationary heat uses in the domestic sector and in industry.

Using steam reforming of natural gas integrated in the end-use application of a fuel cell, as it is today a conventional solution, but is incompatible with a deep decarbonisation policy. Production of hydrogen with zero-carbon electricity might be a solution for deep decarbonisation. A large-scale application of hydrogen as an energy carrier requires development of new industrial base and large scale of end-uses poses the issue of distribution of hydrogen.

The large-scale use of hydrogen in end-uses implies development of a pipeline-based distribution system, similar to the gas distribution infrastructure. The hydrogen infrastructure comprises high-pressure backbone pipelines and medium to low pressure pipelines at a local level. Due to technical reasons, the currently available gas infrastructure is not fully appropriate for hydrogen and needs adaptations of significant investment cost. The system also requires hydrogen storage at a large scale and in particular in salt caverns and other facilities, similarly to the storage of conventional fuels. Another possibility for the distribution system of hydrogen is the use of trucks, more precisely hydrogen tube trailers, which transports compressed hydrogen (180-250 bar) in steel tubes. Each trailer can transport about 280-720 kg of hydrogen. [3]

The business model of hydrogen infrastructure is similar to the business model of gas distribution. Unsupported private investment is rather unlikely to be able to develop the network at a full scale. This is due to the uncertainty regarding the size and the pace of development of the hydrogen market, which to develop requires large-scale distribution. A market coordination failure, manifested as lack of appropriate infrastructure in relation to the targeted hydrogen market could be expected. Public support and intervention, notably for development of infrastructure or industrial base, if appropriately designed, can achieve a positive externality regarding the benefits of the consumers from hydrogen availability for end-uses in a decarbonised society.

Evidently, the hydrogen (pipeline) infrastructure at a large-scale constitutes a natural monopoly. Therefore, there is scope to apply unbundling between network ownership and operation and commercial business in hydrogen production and sales. The scope for interoperability of hydrogen infrastructures within the EU internal market for hydrogen is important. The benefits of an EU market integration are similar to other networks, and regard development of competition, sharing of storage resources, and the security of supply when facing technical shortages.

Integration of the hydrogen markets across the EU is also a prerequisite for the integration of the hydrogen upstream market.

The upstream supply of hydrogen is expected to be domestic in the EU,³ in contrast to the gas market, as this is the most efficient way from a systems perspective (transporting electricity if required is much more efficient than transporting hydrogen). It would require integration of the power markets extended by the development of the electrolysis facilities and, if at sufficiently large scale, the feeding of hydrogen networks. The development of such a large-scale hydrogen infrastructure and markets is a huge endeavour and requires long and a well-coordinated preparation at a European level.

The business of smaller-scale hydrogen supply to specific or niche markets is possible too and feasible to develop probably also on a pure private basis. For example,

³ While currently import/export plans for hydrogen exist in other parts of the world (e.g. Japan); the hydrogen is not derived from carbon free sources. It is expected that domestic carbon free hydrogen production is the best option for Europe including to increase energy independence, as well as security of supply.

development of small-scale electrolysis located close to the hydrogen refuelling stations, distribution of hydrogen in pressurized tanks or in tubes containing liquefied hydrogen. They constitute an appropriate business model for a small or medium size market for hydrogen, for example regarding fuel cells in the transport sector or selected transport modes (e.g. long distance road freight). Small-scale electrolysis is more expensive than large-scale, but the effect of dis-economies of scale is not very high due to the modular structure of electrolyzers. Whether a local electrolyser is economically preferable than a system distributing hydrogen in tanks or tubes is unknown today and depends on specific market conditions. In reality, both ways may well coexist in the future.

The use of hydrogen as a non-energy feedstock in industry (notably in fertiliser production, petrochemicals, as well as some metallurgic applications and others) and refineries is a current practice and the corresponding industry follows mature technological and business solutions. Electrolysis using carbon free electricity may substitute in the future the carbon emitting hydrogen technologies, which are common today. The amounts of hydrogen used in industry as a non-energy feedstock are far smaller than the potential uses of hydrogen in industry in high temperature applications. The current business practices for carbon free hydrogen cover only niche market segments, upscaling of business models are at least required to cover the future requirements of developing hydrogen for energy purposes.

Sector coupling of the mobility sector

This section provides an overview of different options for linking the power to the mobility sector. The focus lies on electric vehicles and hydrogen-fuelled vehicles, and their applicability for a transformation of the mobility sector. Within a deep decarbonisation context, the mobility sector faces the highest challenges in the reduction of carbon emissions. Electrification has a high potential as an option but cannot cover all the transport markets due to range and other limitations. Producing advanced generation biofuels to fully substitute mineral oil fuels is also a valid option, which however is limited by the availability of sustainably produced biomass feedstock in the production of advanced biofuels. Hydrogen as an energy carrier in transport depends crucially on the fuel cell technology, which is currently expensive and the expectations about cost reductions in the future are highly uncertain, although improvements have occurred in recent years. Otherwise, the fuel cells would present a robust solution with wide coverage across all transport means.

Overview of the mobility sector

The mobility sector accounts for about one third of total EU final energy demand. According to the projections of the EU Reference Scenario 2016 (E3M et al., 2016⁴) the current share of 31% will slightly increase up to 33% in 2050. Total final energy demand of the mobility sector until 2050 will stay rather constant showing fluctuations around 350 Mtoe. Road transport accounts for the largest share of final energy demand of the mobility sector (more than 250 Mtoe), followed by aviation.

Figure 2 illustrates the transport activity (based on passenger or freight kilometres) and energy demand indexed to 1995. The figure shows that the activity in the mobility sector is expected to grow significantly in the next decades. Due to the shift in economy towards more services and information activities, a weakening of activity growth is projected beyond 2030. However, as indicated above, energy demand stays almost constant and will decouple from transport activity.

⁴ E3M et al. (2016): "EU Reference Scenario 2016 – Energy, transport and GHG emissions – Trends to 2050", European Commission

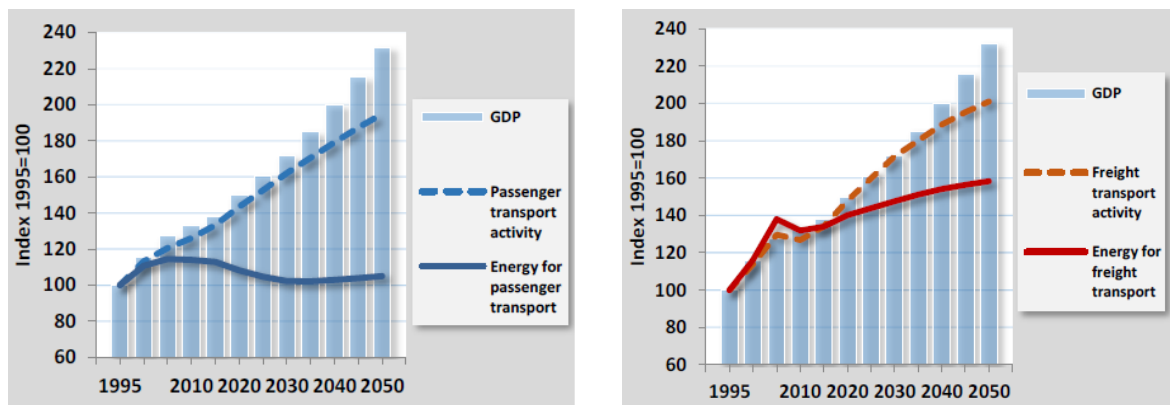


Figure 2: Trends in passenger transport activity (left) and freight transport (right, excl. international shipping) and energy consumption (E3M et al., 2016)

The decoupling of transport activity and final energy demand is explained by efficiency improvements of technologies and fuel mix. Until 2030 the efficiency in passenger transport will be affected by regulations on CO₂ emission standards for light duty vehicles. After 2030 the gradual renewal of the vehicle fleet, advanced technologies and increasing fuel prices result in an efficiency increase of 36% by 2050. Efficiency for freight transport with heavy good vehicles is expected to improve by 23% until 2050.

The relatively long lifetime of the rolling stock in rail transportation is a reason for lower efficiency gains compared to road transport. Further electrification will lead to an improvement of 31 % and 29 % by 2050 for passenger and freight rail respectively. The largest efficiency gains (around 41%) are expected for passenger aviation due to more efficient aircrafts and a renewal of the fleet.

The decarbonisation of the mobility sector is crucial to meet the European emission reduction targets. However, the EU final energy demand of the mobility sector is still met by about 95% with fossil fuels. In contrast to the electricity and heating sector which have already seen significantly increasing shares of renewable energy supply (solar PV, wind energy, solar thermal, biomass), renewable energy technologies are not widely applied in the mobility sector yet. Biofuels are one option for direct renewable energy use in the mobility sector. However, biomass resources are limited and there will be an increase in land use competition between food and energy crops, and the use of biomass for the mobility sector conflicts with the use of bioenergy in the electricity and heating sector. Further the sustainability criteria for bioenergy are becoming stricter and proposed legislation plans to entirely phase out food based biofuels. The coupling of the power and mobility sector, either by direct use of electricity in electric vehicles or electricity-based production of hydrogen and its use in hydrogen fuelled vehicles, are the most discussed options for a decarbonisation of the mobility sector.

Within this study, we distinguish between four different mobility segments:

1. Railway
2. Aviation
3. Shipping
4. Road transport covering cars and trucks

Applicability of hydrogen-fuelled vehicles in the mobility sector

A possibility for decarbonizing the mobility sector is the use of hydrogen in fuel cell electric vehicles (FCEV) as an alternative or in combination with electric vehicles with batteries (BEV); particularly for some transport modes FCEVs are a better adapted

solution compared to BEVs. Today, several projects and business cases already exist in several mobility sectors, e.g. passenger vehicles, trucks, buses, and even ferries. For realising these projects, an infrastructure of refuelling stations needs to be implemented.

Required infrastructure changes (refuelling station)

To support the development of the hydrogen-fuelled mobility sector, the infrastructure needs to be built, i.e. hydrogen production, storage, distribution and refuelling stations. Worldwide there are 280 active hydrogen refuelling stations, of which 92 are in Europe [4], and at the beginning of 2017 there were 140 stations in planning, construction or commissioning phase. Investing in hydrogen refuelling stations today is financially challenging, due to the low utilization rate, which is why most of them are built with funding support ; the capital costs of a refuelling station range from 1.2 to 8.2 million \$/(kg H₂), depending on the production of hydrogen on-site or off-site, how the hydrogen being produced off-site is transported, and the size of the refuelling station [5].

There are different possibilities to install a hydrogen refuelling station for all types of hydrogen vehicles: [5]

1. **Integration in an existing refuelling station:** hydrogen as an additional fuel option. The prerequisite is that there is still enough space available for the storage and dispensers of hydrogen. This option is economically the most interesting option, as it leverages on existing infrastructure, such as the service building. [6] [7] For example, Shell today builds all his hydrogen refuelling stations in existing ones. Furthermore, these locations are already known as refuelling stations to vehicle users.
2. **Greenfield project:** a new, standalone refuelling station.
3. **Mobile refuelling station:** intended for launching a market at a location without hydrogen refuelling station or for demonstration projects.

In a mature market refuelling stations integrated in existing ones are more likely.

There are two different options for the hydrogen production for refuelling station that impact the total costs of the refuelling station.

1. The first option is the production of hydrogen with an **on-site electrolyser**. This will increase the total investment costs of the refuelling station, due to the cost of the electrolyser. Furthermore, the electricity cost might be relatively high, since it might be challenging to source excess renewable electricity in the area where the refuelling station is situated.
2. The second option is **off-site hydrogen production** at a location nearby, with cheap excess renewable electricity. This reduces the investment costs of the refuelling station, but it adds the costs of transporting the hydrogen from the production site to the hydrogen refuelling station. Today, the transport of hydrogen is mostly done with compressed hydrogen truck trailers (tube trailers) since it is cheaper than liquefied hydrogen for the relatively small volumes needed so far. Liquefaction is very energy intensive, amounting to 20 to 30% of the energy content of hydrogen [8] [9]. Furthermore, liquefied hydrogen requires a management of the boil-off, which is needed to maintain ambient pressure. Typically, the boil-off gas is compressed and stored in an auxiliary gaseous storage system, and is therefore less of a problem. The high capital costs continue however to be an impediment.

For the different type of vehicles, distinction in types of refuelling stations can be found.

Distributed refuelling

For passenger vehicles, the refuelling stations are geographically distributed. There are more than 115,000 petrol stations in Europe [10]. One refuelling station distributed about 5-10 million litres of fuel every year [11].

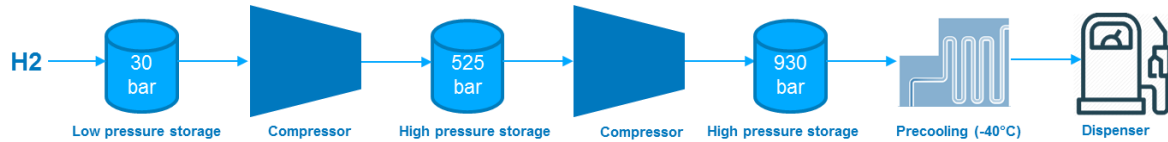


Figure 3: Hydrogen refuelling station for passenger vehicles with two compressor stages

In case of hydrogen refuelling stations, two compressor stages are needed to decrease the storage size needed in the passenger vehicle as well as to reduce the refuelling time to a few minutes.

In Germany, a project has started (H₂ Mobility Germany) to build 100 hydrogen refuelling stations for 2018-2019 [12].

Central refuelling for trucks

There are about 4,400 traditional refuelling stations for heavy duty trucks in Europe with about 370 heavy duty trucks daily using each station.

A traditional refuelling station sells about 12 million litres per year. Therefore, central refuelling stations have a lower marginal cost than distributed refuelling stations, which has resulted in many demonstration projects and start-ups for the case of buses, trucks, and taxis:

- In Europe about 20 H₂ refuelling stations have been funded by FCH JU [13].
- For the central hydrogen refuelling stations, there are several phases for the H₂ daily consumption increase when the number of hydrogen vehicles increases due to the uptake of hydrogen:
 - Phase 1 – 5 buses – 125 kg H₂/day
 - Phase 2 – 5-20 buses – 125-500 kg H₂/day
 - Phase 3 – more than 20 buses – 500-1000 kg H₂/day

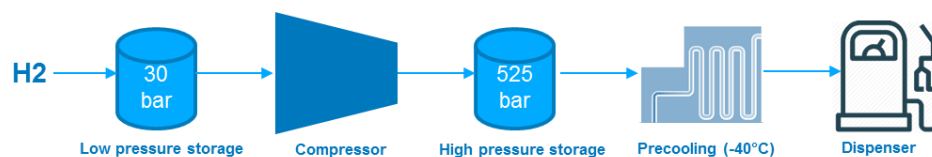


Figure 4: Hydrogen refuelling station for trucks or buses with one compressor stage

For buses and trucks one compressor stage is sufficient in hydrogen refuelling stations, since the storage size can be larger than for passenger vehicles.

Current characteristics of hydrogen-fuelled vehicles and expected development

Carbon-free hydrogen fuelled vehicles have the advantage of only emitting water vapour and thus being 100% emission free. Industrial trucks, buses, commercial trucks, taxis, and passenger vehicles will be analysed. The applications for buses, taxis, and

passenger vehicles attract more attention due to the size of the market and thus costing information is more readily available for these applications than for others.

Industrial trucks

Industrial trucks, such as forklifts and tow trucks, run on the road or on a rail system, usually in enclosed areas. The powertrain is either electric or based on an internal combustion engine (ICE). The most common storage technology for electrically driven industrial trucks is the lead acid battery storage [5].

Fuel cell trucks are suitable for indoor activities, due to the absence of harmful exhaust emissions and low noise levels. An advantage over the battery solution is the higher operational flexibility, due to the short time for refuelling and constant availability of full lifting power. Therefore, in case of multi-shift operation, substantial cost reductions are possible compared to battery technologies [14].

The market today consists of 11,000 fuel cell industrial trucks in the USA, with an average fleet size of 100 trucks. In Europe, there are about 140 fuel cell industrial trucks deployed in demonstration fleets (HyLIFT Europe project)) [5].

Buses

Buses today are the most tested vehicles for hydrogen applications, with the first applications occurring in 1990 in the USA. Fuel cell electric buses (FCEB) receive promotion mostly in cities as a clean mobility option. FCEBs today typically consist of two fuel cell system of around 100 kW with a small battery to recuperate the braking energy, making them de facto hybrid vehicles. They carry about 30-50 kg of compressed hydrogen at 350 bar. The technical maturity level is already an achievement, however the FCEB have a minority share in the market due to the higher costs compared to ICE buses. The investment cost for FCEB today is around € 650,000 while for the diesel buses it is around €250,000. Currently, maintenance costs are higher for FCEB than diesel buses, i.e. 0.40 €/km for the FCEB compared to 0.30 €/km for the diesel buses, however this could be improved if the technology is widespread. [5]

Today	FCEB	Diesel bus
Price	€650,000	€250,000
Range	350-450 km	350-450 km
Maintenance costs	0.40 €/km	0.30 €/km
Fuel consumption	8-10 kg H ₂ /100km ~ 267-333 kWh/100 km (LHV)	24-40 l/100 km ~ 213-356 kWh/100 km (LHV)
Refuelling time	10-20 minutes	< 5 minutes
CO ₂ emissions wheel-to-wheel	0	892 g/km CO ₂ [15]

Table 1: Cost specifications, fuel consumption, refuelling time and CO₂ emissions of the fuel cell electric bus compared to the Diesel bus

A cost reduction to below €500,000 is expected for 2020, and even €350,000 according to FCH JU [16]. This cost reduction will be dependent on the accumulated sales of FCEBs, determining the learning curve leading to cost reductions.

The market today consists of several small fleets worldwide which are publicly funded, in Europe, USA and Asia.

Commercial and heavy-duty trucks

Heavy duty trucks represent less than 5% of the vehicles stock, but represent about 30% of the CO₂ emissions since Heavy duty trucks travel significantly more vehicle kilometres than other road vehicles (Heavy duty trucks travel over three times more than the average passenger car) and consume more fuel per kilometre driven. [17] [18] [19] [20]

2019-2020	Hydrogen truck (Nikola)	Electric semi-truck ⁵ (Tesla)	Diesel truck
Price	NA	\$150,000	\$120,000
Range	1280-1960 km	480-800 km	800-1000 km
Weight capacity	32 ton	10 ton	10 ton

Table 2: Cost specifications, range and weight capacity of the hydrogen truck compared to the electric truck

Therefore, it is important to change the technology of this mobility segment to reduce greenhouse gases. Batteries have not yet succeeded to penetrate the market since these trucks do long distances and therefore would need very heavy batteries with a large volume, which is not feasible, as illustrated in Figure 5. However, Tesla will release in 2019 an electric transport truck for the expected price of \$150,000. [21] This not-yet-released semi-truck has a limit driving range, a low payload capacity and a relatively high cost, thus the success of it remains to be seen. Today, smaller commercial trucks already exist that run on a fuel cell. Some first prototypes exist for heavy duty trucks, but still need to be tested over long distances. An example of such a prototype is the fuel cell heavy duty truck in Switzerland. [22]

25 kg of hydrogen with fuel cell system vs 260kWh battery *

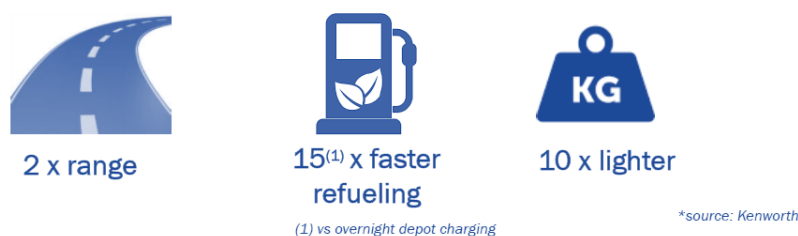


Figure 5: The advantages of the fuel cell compared to a battery for buses and trucks

Taxis

A taxi operating cycle contains many starts and stops due to the traffic. Therefore, it is very suitable for an electric drive system with regenerative braking. A taxi has also very varied duty cycles and daily driving distances, occasionally requiring a long range. Therefore, battery electric propulsion is not perfectly suited, due to the range required and the long recharging time. Nowadays, there exists a plug-in hybrid configuration with fuel cells extending the range of the taxi. In case that a hydrogen refuelling distribution network would be in place, this fuel cell could be replenished quickly. An example is the fuel cell Black Cab used for the 2012 Olympics in London, combining a 14 kWh Li-Ion battery with a 3.7kg H₂ tank (at 350 bar) and a 30 kW fuel cell [23].

The Toyota Mirai has been delivered as a taxi in Paris for the Hype project (alongside other models), with a total range of 502 km. The vehicle has a 114 kW Fuel cell, a 5 kg

⁵ The Tesla truck is called semi-truck because of its semi-autonomous driving capacity

700 bar H₂ storage tank weighing 87 kg, and a 1.6 kWh battery. Air Liquide has installed the first H₂ recharging station in Paris in collaboration with taxi start-up STEP, and with the support of Paris City Council and Ile-de-France. Today, it recharges more than 50 taxis and the capacity is planned to increase to 600 taxis by 2020 [24] [25].

Cost specifications and maintenance can be found in the table of the passenger vehicles, see Table 2.

Passenger vehicles

Today, manufacturers offer hydrogen passenger vehicles, producing only about 100 fuel cell vehicles per year. The market may see a growth to thousands of cars before 2020. In 2017, 10 brands were selling H₂ fuel cell vehicles, e.g. Toyota, Lexus, Daimler, and Hyundai. Since the launch of hydrogen passenger vehicles, the sales reached 5,500 cars worldwide. Approx. 10% of these vehicles sales were in Europe and close to 2,400 were in the first three quarters of 2017. Passenger vehicles are typically equipped with PEM fuel cells of around 100 kW.

The cost of one H₂ passenger vehicle is around €60,000 today, [5] thus about double the average gasoline/diesel passenger vehicle. They store usually 4-7 kg of H₂ on board at 700 bar.

Today	H ₂ passenger vehicle	Gasoline passenger vehicle	Battery electric passenger vehicle
Cost	€60,000	€25,000	€30,000-€40,000
Range	400-700 km	800 km	100-250 km
Maintenance costs	15 €/100 km	15 €/100 km	15 €/100 km
Fuel consumption	1.1-1.15 kg H ₂ /100km ~ 33-66 kWh/100 km (LHV)	6 l/100 km ~ 53 kWh/100 km (LHV)	20 kWh/100 km
Refuelling time	3-5 minutes	1-3 minutes	90-240 minutes
CO ₂ emissions wheel-to-wheel	0	118-143 g/km CO ₂	0

Table 3: Cost specifications, fuel consumption, refuelling time and CO₂ emissions of the H₂ passenger vehicle compared to the gasoline passenger vehicle and the EV

Other transport modes

- **Railway:** Demonstrations exist today for light rail vehicles, called Hydrail (hydrogen railway). These could be used in locations where electricity rail infrastructures cannot be built. The two prototypes that exist today are shunting locomotives and railcars, which are fuel cell powered and are used for public rail passenger transport. [26] Austria's Zillertal Railway is also opting for hydrogen fuel cell trains for the replacement of a 32 km line between Jenbach and Mayrhofen, that today uses a diesel locomotive. The electricity rail infrastructure was opposed by municipalities for visual intrusion. Zillertal Railway will build a prototype and launch a tender for the series trains by 2022. [27]
- **Ships:** Today, there are no fuel cells scaled for large merchant vessels, since these are too expensive compared to heavy fuel diesel engine used today in these vessels.

There are however applications in trial phase in small passenger ships, ferries or recreational ships. [26]

- **Aviation:** Small propeller aircrafts have been tested in small demonstration projects, where these aircrafts were fitted with PEM fuel cells and Li-Ion batteries for the drive. However, also in larger commercial aircraft hydrogen-powered fuel cells are viewed as potential energy providers for aircraft since already in space travels they are used. [26]

Applicability of electric vehicles in the mobility sector

The electrification of the mobility sector is already widely applied for railway systems. In future, the focus will be on further penetration in road transport, making use of improved battery capacity and ranges. For shipping and aviation, electrification is more difficult. This section gives a comprehensive overview of the applicability of electricity for the individual mobility segments until 2050.

Railway

Electrified railway networks have been in use since the late 19th century. The proven technology makes it by far the most electrified transport mode. 53% of the 210,000 km railway lines of the EU and 52% of the 350,000 km long railway system of Europe are electrified lines (UIC 2017⁶). In the coming years, further electrification of remote tracks is expected, reducing the diesel-powered rolling stock. As it is often not cost-efficient to install new overhead lines in rural areas, battery driven concepts for remote tracks are gaining attention and are currently tested in research projects, e.g. in the UK and Germany, as hybrid or dual-mode propulsion systems (European Commission, 2017⁷). The research examines various charging technologies, including platform side charging stations (e.g. RailBaar, an automatic overhead electric charging station⁸).

Aviation

Big aircrafts used for intercontinental and international flights are characterised by a high total energy consumption per flight. Frequent recharging is technically not feasible. The energy density of batteries is currently too low to cover the energy consumption with acceptable fuel storage volumes and concepts are only applicable for smaller engines. For aviation in general, the power-to-weight ratios for battery technology are still a long way short of what is required for full electrification. Therefore, is not expected that aviation as we know it can be fully electrified before 2030.

R&D activity regarding the compliance of future CO₂ standards such as for hybrid concepts is taking place. Research includes new technologies on energy storage and supra conduction and improved reliability of electric motors. In addition, research is done on very small aircrafts for which electrification is easier. For example, Siemens and Airbus presented in 2015 a 2 passenger aircraft with 200 km range.

Shipping

Diesel generators (internal combustion motors) produce the electricity used on board for lighting, fans, pumps, compressors, and electronics. In Europe, over 500 ships under EU Member State flags use electricity for propelling instead of mechanical means. Electric propulsion offers advantages in performance and efficiency. Typical applications of electric propulsion systems today are vessels with special operational needs like

⁶ UIC (2017): Railway Statistics – 2016 synopsis, International Union of Railways

⁷ European Commission (2017): "Electrification of the transport system", Directorate-General for Research and Innovation

⁸ For more information, see <http://opbrid.info/railbaar>

icebreakers or oceanographic research vessels, passenger cruise ships (noise reduction), hybrid forms for offshore platform support, inland shipping and ships for short distances.

The common option for electric propulsion in shipping are the diesel engines. The batteries are currently too expensive for larger deployment and the energy densities are still too low. With further improvement of energy densities, cargo vessels could use battery electricity assuming installation of recharging facilities and battery swap systems. Building a charging infrastructure for ships presents challenges, if it implies high peak charging currents. In addition, the trend for alternative fuels in shipping is going toward LNG, and not toward electrification.

Road transport

Road transport is a suitable field for electrification. There are two main concepts that compete with hydrogen-fuelled technologies: battery driven concepts and direct connections to overhead lines. In this report, battery swap is not discussed because of the unsuccessful results that are achieved until now (LeVine, 2013⁹).

Several European governments currently support battery electric vehicles as a promising solution for the decarbonisation of the car fleet. The support applies to pure electric vehicles (EVs) or on plug-in hybrid models. In 2015, about 500,000 EVs were circulating in Europe.

For trucks, the battery applications usually imply a limited range due to size and weight, thus limiting battery applications for now to urban area trips. In the UK, the Netherlands and Germany, the e-buses serve to electrify public transport. Several automobile manufacturers are introducing electric cargo trucks e.g. the electric truck of Build Your Dreams (BYD) Company Ltd and recently TESLA's electric truck. Further development for electric road transport the situation could change for trucks, making electrification also possible for long distance transport.

An alternative concept for trucks is to provide them with a direct connection to electricity overhead lines. This technology is mature and applies to city buses-trolleys. The application for long-distance travelling trucks requires development of overhead lines in motorways; pilot projects of overhead contact line trucks on highways are currently in operation. Alternatives to cable charging include battery swapping or continuous charging or at least charging while the bus is on the move.

Figure 6 illustrates the projected EU activity of passenger cars and vans until 2050 by type and fuel for the reference scenario. The market domination of gasoline and diesel fuelled cars will strongly decrease by 2050 although they will still account for almost 50% in 2050. The highest uptake is for hybrid cars (conventional cars with electrical recuperation) with 31%. Despite the ambitious goals of some EU Member States, the EU Reference Scenarios show only a limited uptake of electric vehicles with a share of 9% for plug-in hybrids and 6% for pure electric vehicles in 2050.

⁹ For more information see: <https://qz.com/88871/better-place-shai-agassi-swappable-electric-car-batteries/>

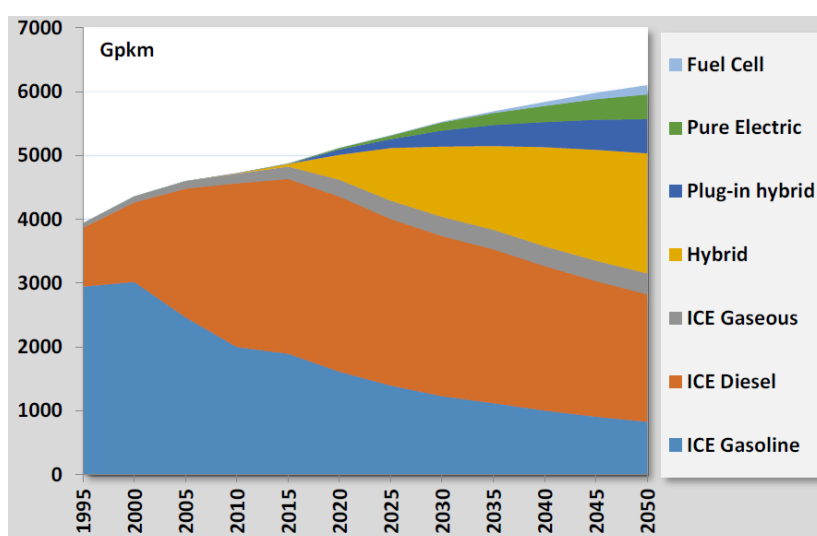


Figure 6: Evolution of activity of passenger cars and vans by type and fuel (E3M et al., 2016)

To enable the wide-scale electrification of cars and trucks, the road transport infrastructure requires significant changes. To allow long-distance travels of battery electric vehicles that exceed the maximum range of the vehicle, a distributed charging station network is required similar to the existing refuelling station distribution. Fast charging stations are required near highways to allow for fast recharging times. Furthermore, private and sufficient public charging stations are required to allow charging at home and in cities.

Today, a higher coverage of charging stations is necessary to develop in most EU Member States to promote EVs. However, the charging stations existing today suffer from low utilisation rates that undermine their economic viability and discourage further investment in charging stations. Figure 7 shows the number of plug-in electric vehicles (including plug-in hybrids and pure EVs) per charging point in European countries. Only 10 out of the 33 countries have more than five plug-in electric vehicles per charging point.

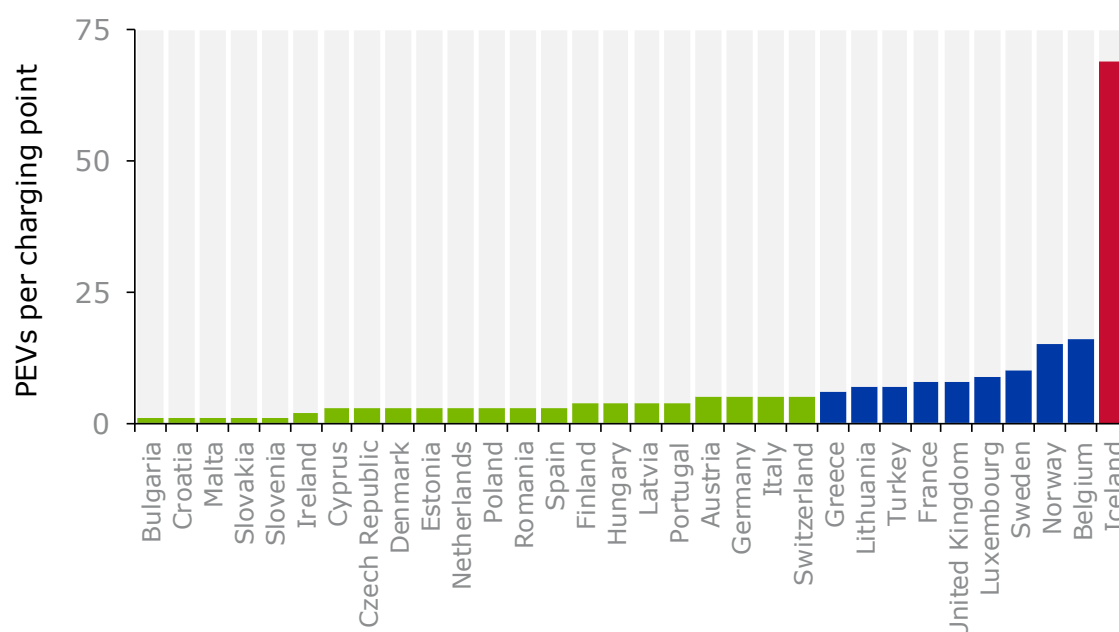


Figure 7: Plug-in electric vehicles per charging point; 0-5 (blue), 5-25 (green), >25 (red); (Source: Ecofys based on EAFO 2017¹⁰)

Trucks using overhead lines to cover the electricity demand rely on overhead lines for long-distance travels. Overhead lines could cover specific routes or most highways to allow maximum flexibility. In some European cities, overhead line systems exist for buses (e.g. Tallinn, Estonia).

Impact of road transport electrification on the power sector

The electrification of road transport also has impacts on the power sector. In general, electrification increases total electricity demand and is likely to increase peak demand, which requires grid expansions. Firstly, the increase in local (peak) demand, especially in residential areas with high EV use and areas with fast charging stations, stresses the local distribution grid. Secondly, the increase in system (peak) demand and residential load centres puts pressure on the transmission grid. Intelligent loading and use of EV batteries as a local flexibility source could reduce potential grid constraints. Simulations of the power system show that intelligent loading systems can offset the adverse effects on peak load. However, the implementation of this intelligence at a large-scale is costly and requires technological development.

Linking the power sector and hydrogen-demanding industry

The power-to-hydrogen conversion chain

Today hydrogen is traditionally produced with a Steam Methane Reformer (SMR), which produces hydrogen from natural gas ($\text{CH}_4 + \text{H}_2\text{O} \leftrightarrow \text{H}_2 + \text{CO}$) at high temperatures of about 700-1100 °C in the presence of a catalyst. For large industries (refineries, fertilizer industries) such an SMR is usually found on-site. The cost of H_2 produced with a SMR is in the range of 1,800-2,250 €/t H_2 and it produces about 7.2 kg CO_2 /kg H_2 . The cost of hydrogen from steam methane reformers is dependent on the carbon price

¹⁰ EAFO (2017): Electric vehicle charging infrastructure, <http://www.eafo.eu/electric-vehicle-charging-infrastructure>, accessed 16th Nov 2017, European Alternative Fuels Observatory

in the majority of cases, as they are mainly found in large industries and therefore are included in the ETS. [28] has found that already a price of 28€/t CO₂ would increase the cost of hydrogen from SMR by 202 €/tH₂. [29]

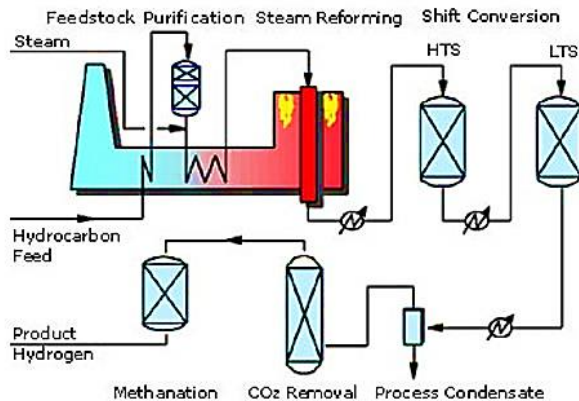


Table 4: Steam Methane Reforming process

A carbon-free alternative is producing hydrogen with an on-site electrolyser that is electrically fed by locally produced renewable electricity, e.g. with solar panels or wind turbines. A constant hydrogen flow is guaranteed by oversizing the electrolyser and installing a gaseous storage (30 bar). This would reduce the greenhouse gas emissions footprint considerably. An alkaline electrolyser today costs between 650 and 1,000 €/kW with an efficiency of 55 kWh/kg H₂. The cost of H₂ produced on site with an electrolyser, compressor and gaseous storage is between 2,810-3,200 €/ton H₂ with a 55% load factor and low electricity cost of 35 €/MWh, without considering the costs of the renewable energy investment.

Today the production of hydrogen with SMR is still cheaper than carbon-free hydrogen production with an electrolyser. At a carbon price of 78-140 €/kg CO₂ green hydrogen production could become economically more interesting. However, this calculation does not consider other possible side revenues streams from the carbon-free hydrogen production, such as oxygen sales, heat at 85°C for district heating and grid services in the form of flexibility delivered by the electrolyser.

Sustainable hydrogen-based processes in industry

Cement industry

The cement industry is a multi-stage process. Typically, a cement plant consumes about 100 kWh/tonne cement of electricity and 900 kWh/tonne cement of heat. A typical plant size is 1 mtpa cement and in case of a flat profile a production of 114 tonne cement/hour. It implies a demand of 11 MWh electricity and 101 MWh heat. Heat requirements are at a high temperature of around 800-1,200 °C in a tower.

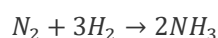
Therefore, there are two reasons why a hydrogen fuel cell will not suffice to produce combined heat and power. One is the too high temperature heat demand and the other is the electricity to heat ratio of a cogeneration unit which is incompatible with the electricity-heat ratio of demand in the cement industry. Alternatively, there is a possibility to use a hydrogen in the cement kiln to replace part of the fossil fuels. Hydrogen has flame temperatures of about 3200 °C. However, replacing traditional fuels (coal, petroleum) with hydrogen in the rotary kiln of the cement factory can be complicated requiring engineering adaptations at a significant scale. The reasons are the following [28]:

- The change of composition of the off-gas would require changes in the downstream processes.
- A considerable amount of hydrogen would leave the furnace with the off-gas, limiting the benefits.
- Due to the simultaneous injection of air, hydrogen blast furnaces present safety issues.

Today, there are no European projects dealing with use of hydrogen in furnaces.

Fertilizer industry

The fertilizer industry requires hydrogen to produce ammonia, which is used in most fertilizers, such as urea, ammonium nitrate, and diammonium phosphate. The following chemical reaction produces ammonia with nitrogen and hydrogen:



This reaction is exothermic, thus besides compressing the nitrogen and hydrogen, no additional energy is needed since thermal energy is recuperated with heat exchangers. Therefore, a fuel cell could be useful to produce electricity for the ammonia plant.

But, as is evident in the equation above there is also a direct hydrogen demand. For 1 ton of ammonia, 0.18 tonne of hydrogen is needed. A typical plant size is 0.7 mtpa of ammonia. This results in 0.12 mtpa of hydrogen or thus 14.1 tonne H₂ /hour in case of a flat profile. Today, ammonia plants use SMR to produce hydrogen from natural gas. To have a constant output of carbon-free hydrogen, oversizing of the electrolyser would be necessary, as well as installing a large (gaseous) hydrogen storage, since variable renewable energy sources do not have a constant electricity output.

Thus, the ammonia industry would be the most promising industry due to its large direct hydrogen demand. The EU fertilizer industry has a total ammonia capacity of 21 mtpa or thus a total demand of 3.7 mtpa H₂.

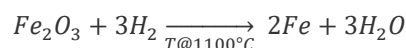
Steel industry

The steel industry is a multi-stage process with an electricity consumption of 390 kWh/tonne steel and heat consumption of about 205 kWh/tonne steel at temperatures of 900-1300 °C [30]. Also chemical energy consumption of 125 kWh/tonne steel is required in the form of energy arising from the oxidation of elements such as carbon, iron, silicon and the burning of gas in oxy-fuel burners. A typical plant size is 3 mtpa of steel and thus 342 tonne steel/h in case of a flat profile.

The electricity demand is 134 MW and heat demand 70 MW per hour. The high temperature requirements make a fuel cell inappropriate for the full cogeneration. On-site electricity production could use a fuel cell.

Hydrogen produced with high temperature electrolyser, such as the Solid Oxide Fuel Cell SOFC, could be deployed today in existing annealing processes, according to Salzgitter [31]. Hydrogen can create the needed inert atmosphere in the annealing process (inert meaning without oxygen), to prevent the oxidation of steel.

Also, it could be partially used as a reduction agent in the blast furnace instead of carbon. Hydrogen is also less endothermic than reduction by carbon which is used today and thus improves the heat balance [32].



This would result in a flat profile of 9 tonne H₂ /h to produce 342 tonne steel/h.

Using the waste heat from the steel processes for the electrolysis could increase the efficiency of the electrolyser. In case that electricity is too expensive (low availability of renewable electricity), the system at Salzgitter can be switched to a fuel cell mode with natural gas from the grid to have a reliable power supply. Today, such a reversible system from Boeing Company and Sunfire, which is used at Salzgitter, has a maximum power of 100 kW in SOEC mode and 20 kW in SOFC mode [33].

Refining industries

Hydrogen is mainly used in the refineries for the desulphurisation of the crude oil. Due to European regulations and lower crude oil quality, European refineries need to consume high amounts of hydrogen. Currently, the refineries commonly use on-site SMR and hydrogen pipelines for internal transport. Depending on incentives regarding the reduction of carbon intensity, it would be possible to install on-site H₂ production by electrolysis (an example is the P2H project).

A typical refinery produces roughly 5000 ktpa of oil and consumes between 3.2-7.2 kg H₂/tonne oil. This implies an annual H₂ production requirement of 16-36 ktpa or 1.8-4.1 ton H₂/h in case of a flat profile.

Linking the power and heating sector

The power and heating sector have been linked historically on the power supply side through cogeneration. Currently, operation is mostly heat-driven with electricity as a by-product due to limited heat storage facilities and low power prices. Operation may move from heat-driven to electricity-driven cogeneration along with the development of power systems highly based on intermittent renewable sources generation to provide the required flexibility for the power system.

The increasing relevance of electricity to cover heat demand directly calls for power-to-heat applications (both central in district heating systems and decentralised) with the aim to decarbonise the heating sector and provide flexibility to the power sector. In addition to electrification of heat demand there are also other options to decarbonize the heating sector:

- Biomass: First, biomethane can be produced, which is used in existing gas infrastructure. Secondly, pellets can be made that are used in stoves. The main challenge of biomass is the limited availability of biomass that is produced in a sustainable way (e.g. not competing with food production).
- Solar thermal systems: Solar thermal technology uses the sun's energy to generate low-cost, environmentally friendly thermal energy. This energy is used to heat water or other fluids. Solar thermal systems differ from solar photovoltaic (PV) systems, which generate electricity rather than heat. As solar thermal systems are often placed on rooftops, it has limited space available and competes for this space with other systems such as solar PV and green roofs. The relative business case of solar thermal depends highly on country specific factors.
- Geothermal heat: Geothermal energy is the heat from the Earth. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles beneath the Earth's surface. One of the main challenges faced by geothermal developers is the combination of geological uncertainty with high upfront costs and the resulting difficulty in acquiring adequate financing.
- Waste heat: Waste heat that is recovered from industrial processes can be used to provide district heating to the residential buildings and offices. One of the main difficulties for waste heat is the uncertainty, or lack of commitment, of the supply of

waste heat for the economic lifetime of the assets that are required to transport the heat from where it is generated to where the heat demand is.

The focus of this section is on electrification, so not on the other options of decarbonizing the heat demand or on cogeneration.

Overview power-to-heat conversion technologies

Power-to-heat technologies (PtH) act on the power demand side. They can generally be divided into centralized and decentralized applications. The figure below gives an overview on PtH in the residential sector. In the case of centralised PtH, electricity is converted into heat at a location distant to the place of consumption and is distributed via a district heating network. Decentralised PtH is generated close to residential blocks or single houses and can directly be used through fans and radiators, or be stored for later consumption. Storage can be differentiated by external storage and internal storage. External storage is located outside of the product that generates heat, for example a water basin. For internal storage the heat is stored within the same product that is generating it, for example an electric thermal storage system, a technology that stores the heat in ceramic bricks of the heating application itself. So internal storages come in the form of smart electric storage heating, while external storage through buffers can be supplemented by heat pumps and resistive heating.

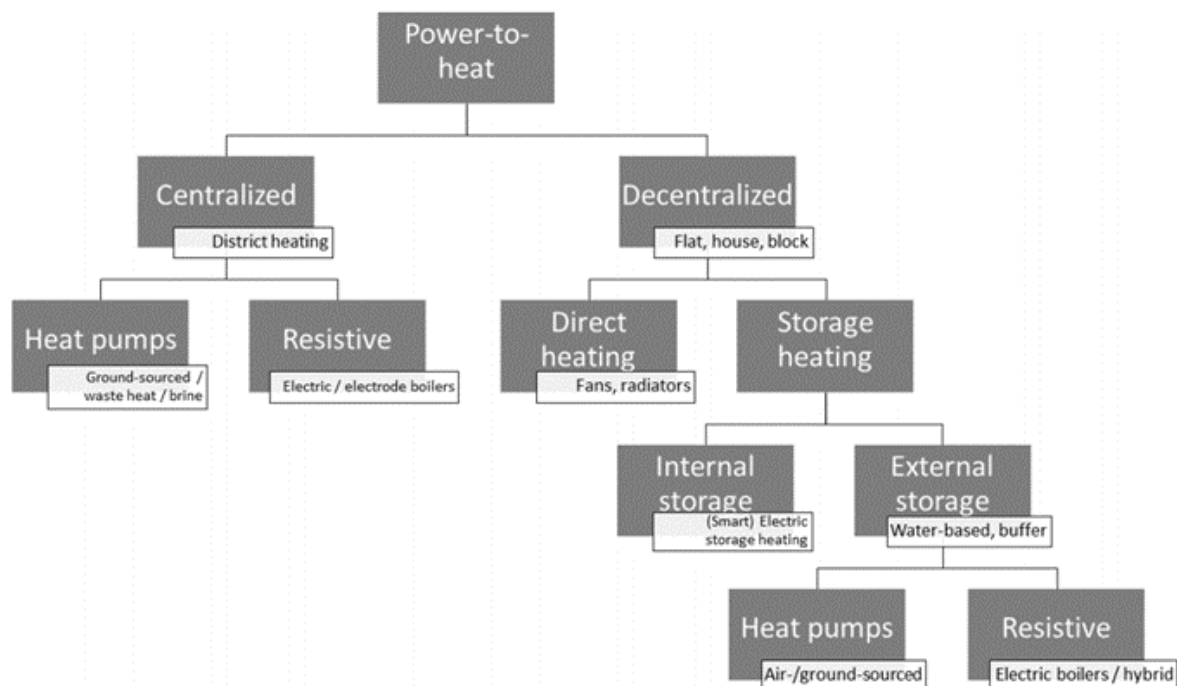


Figure 8: PtH technologies in the residential sector (DIW 2017)

The two main PtH technologies are heat pumps and resistive heating. While heat pumps offer highly efficient heat supply connected to high investment costs, resistive heating has comparably low investment costs but also lacks efficiency. This makes the latter more suitable for peak supply applications, as the need for peak supply is very limited, so the investment cost should be as low as possible and operational cost and/or efficiencies are of less importance.

Heat pump technologies

We distinguish three heat pump technologies:

1. Air source heat pumps using ambient energy in air
2. Water source heat pumps using energy stored in water
3. Ground source or brine heat pumps use geothermal energy stored in the ground using a vertical or horizontal collector

The applicability of heat pump technologies is dependent on local energy resources and building specifications such as access to water or ground, and the space needed for air heat pump systems.

The efficiency of a heat pump is measured using the seasonal performance factor (SPF) and dependent on the building conditions (supply temperature level) and the local environmental conditions (ambient temperature of heat resource). The SPF for space heating (35°C) varies between:

1. 4.5 for air HP
2. < 6 for water HP
3. 4.5 – 5.5 for brine HP

SPFs for higher space heating temperatures can be significantly lower (Ecofys, 2013¹¹).

When comparing European countries, large differences in the market deployment of heat pumps become visible. While markets like Germany, Austria, UK, Belgium, France as well as Italy and Spain are strongly growing, Sweden had already reached saturation levels of more than 20% of the total energy demand for heating and heat pumps account for 45% of the turnover on the heating market in 2014 (Ecofys, 2013; Profu, 2014¹²). The strong uptake in annual heat pump sales in Sweden since the mid-1990's can be explained by a vast increase of the carbon tax.

In contrast to heat pump applications in the residential sector, the industry sector only has limited potential, as most industrial processes require significantly higher temperatures. Still, there exist applications in industries like the nutrition sector, where heat pumps > 100 kW_{th} can provide heat with temperatures up to 130°C.

Resistive heating

Resistive heating can be provided in the form of electric boilers or electric heating elements in boilers that are fuelled by some other form of primary energy as so-called hybrid heating.

In central PtH it can be used in peak times to convert otherwise curtailed renewable energy at low cost. In the industry where heat pumps only provide a limited temperature, it can be used for steam generation. Nevertheless, it has to compete with conventional options and thus has currently only a limited potential. In the residential sector heat pumps have a predominant role but can be supplemented with resistive heating in special cases.

Overview thermal storage options

To enable a shift towards a more power-driven cogeneration and thus more flexibility in the power sector, thermal storage solutions are needed. Not only CHP is a possible application area, but also storages for central (district heating network) and decentral (buildings, industrial) use. The varying heat demand can be balanced on a daily, weekly or seasonal basis. As a result, peak demand, energy consumption and emissions are reduced, and efficiency increased.

¹¹ Ecofys (2013): Heat pump implementation scenarios until 2030

¹² Profu et al. (2014): The heating market in Sweden – an overall view

Thermal energy storages can be categorised by:

- Temperature range (High temperature 300°-600° C for solar thermal, glass and steel industry; Process heating and steam generation 100-250°C; Heating of buildings 25-90°C; air conditioning 5-18° C)
- Storage period: buffer (hours to days); seasonal (months)
- Location: central (renewables power plant, district heating, large industrial) or decentral (buffer storage for buildings)

There are three main thermal storage technologies:

- **Sensible thermal storage:** Sensible storage is characterised by a change of temperature during the storing process. The storage medium is heated or cooled, and the transferred energy depends on the specific heat capacity of the medium. A commonly used option is water due to its low cost, environmental compatibility and high heat capacity. Other storage materials are sand, molten salts and rocks. Sensible heat storages are commonly used in heating systems with buffer storages.
- **Latent thermal storage:** Latent energy storages make use of the energy that is set free during phase changes, mostly from solid to liquid state. The core of latent thermal storages uses phase change materials (PCM). The temperature of the PCM stays mostly constant during the charging process. Growing research interest is directed towards phase change slurries (PCS). Latent heat materials are combined with water to benefit from pumping characteristics and of a liquid while having high energy density levels of latent heat storages.
- **Thermochemical thermal storage:** For thermochemical thermal storage, reversible chemical reactions are used to store and release thermal energy. In a desorption process, heat is charged through the supply of energy and discharged in a sorption process. The process can offer the highest energy densities, but the system configuration is complex and involves high investment costs. There are currently almost no applications and there is a need for further research.

Sensible thermal storage is a proven technology and widely applied in residential heating (central and decentral). Its disadvantages compared to latent and thermochemical heat storage are lower energy densities and thus require larger storage volumes. Latent thermal storages have slower charging rates compared to sensible thermal storage.

As seen in the table below, sensible thermal storage has the least costs, with insulation being the largest driver. With complex constructions, expensive storage materials and a low level of development the cost for latent storage is significantly higher. Materials for thermochemical applications have similar prices as latent thermal storage (here PCM) but need an additional treatment. Main cost-driver is the complex reactor and further required peripherals.

TES System	Capacity (kWh/t)	Power (MW)	Efficiency (%)	Storage period	Cost (€/kWh)
Sensible (hot water)	10-50	0.001-10	50-90	Days to months	0.1-10
Latent (PCM)	50-150	0.001-1	75-90	Hours to months	10-50
Thermochemical	120-250	0.01-1	75-100	Hours to days	8-100

Table 5: Thermal storage techniques

Central, seasonal storages require large storage volumes but have only 1-1,5 cycles per year and therefore require cheap mediums like water but very high insulation to reduce heat losses. For central residential heating, the district heating network is also used as a buffer storage.

Benefits for electricity sector

The growing share of renewables in power generation leads to increasing generation peaks and curtailment due to grid constraints. In general, the increase in electrification leads to a higher electricity demand but it can also add system flexibility if the demand is shifted intelligently into times of high supply. The excess electricity can be used by increasing the electricity demand during these times.

The flexibility potential of power-to-heat technologies is dependent on the heat demand and the ability to store the heat. Intelligently controlled power-to-heat applications in combination with thermal storage have multiple benefits for the power sector based on their increase in electricity demand-side management potential. The enlargement of the flexibility of the electricity system leads to the following benefits:

1. **Local integration of renewable energies (short-term):** The use of excess electricity for local heat generation reduces local curtailment and thus improves local integration of renewable energies.
2. **System balancing (short-term):** On the system level, the flexible load can be used for system balancing reducing system operation costs by avoiding operation of expensive power plants (Ecofys, Prognos, 2011¹³).
3. **Reduced required installed capacity (long-term):** A significant increase in system flexibility that is controlled based on the system situation can have a long-term impact on the required available installed capacity of the power plant fleet. This can lead to long-term savings for the provision of power plants, especially if the capacity is remunerated by the market, e.g. via capacity markets (Ecofys, 2016¹⁴).

The potential benefits are dependent on the technical controllability of the power-to-heat applications and the market incentives. In the industry and commercial sectors, demand-side management technologies are increasingly used to reduce energy costs. For households, the roll-out of intelligent metering devices offers the opportunity of intelligent demand-side management in this sector. However, to make most use of the potential benefits of power-to-heat for the power sector, market incentives need to be set accordingly. Demand-side flexibilities will only be operated in a system friendly manner, if the wholesale or control energy markets give sufficient financial incentives. On the other side, a system oriented behaviour can contradict with the local grid situation at the same time. Thus, system prices can set contradictory incentives. Local markets could set the right prices to reduce local grid congestion and improve regional renewable energy integration, but could also conflict with the system situation. In total, a comprehensive approach is needed to use local power-to-heat flexibilities in the most beneficial way.

Hybrid heat pump systems can have strong benefits for the power sector. The combination of an electric heat pump combined with a peak supply technology (e.g. a natural gas boiler) is more flexible than pure electric heat pump systems. The peak supply technology can also be used in high load times of the power system to cover the heat demand if the thermal storage cannot cover the heat demand anymore.

¹³ Ecofys, Prognos (2011): „Potenziale der Wärmepumpe zum Lastmanagement im Strommarkt und zur Netzintegration erneuerbarer Energien“

¹⁴ Ecofys (2016): „Flex-Efficiency. Ein Konzept zur Integration von Effizienz und Flexibilität bei industriellen Verbrauchern“

Linking hydrogen to the heating sector

Hydrogen based heating technologies have not been in focus much of the European debate on the decarbonisation of the heating sector until now. However, there exist multiple technologies that have been applied in international – mostly Asian – markets. There exist four main hydrogen-based technologies for use in households (Dodds et al., 2005¹⁵):

1. **Fuel cell micro-CHP:** The most established hydrogen utilisation is in the form of fuel cell CHPs. However, for buildings the fuel cells micro-CHP runs currently on natural gas, which is converted to hydrogen within the product, therefore it does not interfere so much with the market for hydrogen. While fuel cells are usually known for their highly efficient electricity production, they do also provide heat. Since fuel cells are modular existing small-scale applications can easily be scaled up. Proton-exchange-membranes fuel cells (PEMFC) are the most developed fuel cell technology suitable for decentral residential heating and account for 90% of total fuel cell systems sold. Solid oxides fuel cells (SOFC) are also used in household heating system sizes. Currently, SOFC and PEMFC have total efficiencies of 80-90% and 95% respectively.
2. **Direct flame combustion boiler:** Direct flame combustion boilers powered with hydrogen are functionally identical to European natural gas boilers. In operation, there is no difference for the consumer.
3. **Catalytic boilers:** Hydrogen can be used in catalytic boilers in which it is passed over a reactive metal catalyst. The exothermic chemical reaction produces heat that can be used for domestic heat supply. Catalytic boilers have no flame and do not emit any NO_x in contrast to conventional gas boilers in residential heating.
4. **Gas-powered heat pumps:** Hydrogen can be combusted in gas heat pumps to generate the phase change instead of an electric compressor which is used in electrical heat pumps. Besides this, the concept of both heat pump types is the same.

In Europe, fuel cell programmes have led to first installations in multiple countries. However, hydrogen based heating technologies are not widely distributed in Europe. In the EU, demonstration projects started in 2008 and are part of the goal to install 50 000 systems with a subsequent commercial roll-out until 2020.

In other markets, ambitious goals and support programmes led to a large-scale implementation of fuel cells. Technology deployment of fuel cell micro-CHPs for domestic use was supported in particular in Japan and South Korea. The Japanese support programme with about € 200 million per year for more than 10 years has led to a strong growth and a decrease of prices of 85% in Japan over ten years.

Despite the potential for the decarbonisation of the heating sector and the improved integration of renewable energies by using excess electricity for hydrogen generation, the ability of CHPs to operate during black-out times makes them favourable in certain regions. However, the relatively high investment costs are still a challenge for this technology today. In the future hydrogen could play a bigger role, especially in off-grid areas. Within off-grid areas there are a limited number of flexibility sources that can ensure the balance in the system. Therefore electrolyses and hydrogen could play a relatively big role.

¹⁵ Dodds et al. (2015): Hydrogen and fuel cell technologies for heating: A review, International Journal of Hydrogen Energy, Volume 40, Issue 5, 9 February 2015, pp. 2065-2083

Energy storage and sectoral integration

This chapter lays out the technical options for hydrogen storage. It aims to show the role of hydrogen and methanation to decarbonise the gas grid, and in a broader sense the contribution of hydrogen based flexibilities to the energy transition.

In general, the role of energy storage will become more important in a sustainable energy system in the future. Navigant research estimates that 1,500 GW of additional global energy storage capacity is expected to be installed over the next 10 years for the integration of large scale renewables. There are a variety of technical storage options known that can provide different services for the energy sectors. First, there are storage options for short term (up to minutes) uses that require high power capacity, but low energy capacity, such as supercapacitors, flywheels and some batteries. Secondly, there are options for medium term storage (up to a day), for example batteries and compressed-air-energy-storage (CAES). Finally, there is the need for long-term storage, to bridge the difference in energy supply and demand between seasons, therefore power to gas will play an important role. The most applied form of storage today is pumped hydro storage, which can be used for all of the time scales, and is relatively cheap in certain areas with right conditions (e.g. mountains), which makes it a preferred option. However, this the use of pumped hydro storage will only be applied in a limited number of regions, in other regions power to gas will be required.

Hydrogen storage

Hydrogen can be stored similar to other conventional energy carriers. The energy density of hydrogen rises with increasing compression. Liquefied hydrogen has the highest density and thus requires the least space. However, due to the low boiling point of hydrogen of $-253\text{ }^{\circ}\text{C}$, cryogenic storage systems need strong insulation to reduce evaporation losses. Moreover, liquefaction of hydrogen is energy intensive, amounting to more than 20%-30% of the energy content of hydrogen) and increases the economic costs of storage systems significantly.

Hydrogen can be stored centrally at a large-scale and in decentralised facilities usually close to consumers. Hydrogen can be also stored in small decentralised storage systems. Tanks are suitable for on-site storages close to generation facilities, and for household and mobile storages. Low pressure tanks only hold hydrogen at 50 bar while for intermediate storage pressures up to 1000 bar are possible. To mitigate the weight of the tanks composite materials are used. This is particularly important in the mobility sector. In stationary applications steel tanks provide secure storage.

For centralised hydrogen storage, there exist three main options:

1. **Salt caverns:** The most common option for central hydrogen storage are salt caverns, artificially created underground cavities. They provide large underground storage of more than 500,000 m³ and at more than 200 bar per cavern are possible. Historically salt caverns have been used for natural gas storage but the applicability for hydrogen injection has been shown in projects in the UK and the US. Special focus regarding the hydrogen application is on the materials' hydrogen-tightness but also on the special security requirements that affect the acceptance for this form of storage. The potential of a cavern as a storage solution depends on the geological structures (high potential in Germany, Poland, United Kingdom, Spain, Romania). The main advantages of caverns are the high capacities of single sites and the availability, high safety as well as relatively low costs.
2. **Porous storages:** Hydrogen can be stored in porous storages, old extracted natural porous deposits. In most cases depleted natural gas or oil reservoirs are

used, since they are already well explored. Due to the possible contamination of the hydrogen with hydrocarbons in porous storages, additional “filtering” of the hydrogen can be required after extraction. The high reactivity of hydrogen with different minerals inside porous storages can lead to gas losses and impaired flowing properties.

3. **Aquifers:** A third possibility for hydrogen storage are aquifers. In contrast to porous storages these permeable rock reservoirs were formerly filled with salt water. Regarding gas purity and safety, they suffer the same disadvantages as porous storages and their exploration is challenging.

The best option for a large scale, central hydrogen storage are salt caverns because they are technically hydrogen-tight and are not affected by contamination or biochemical reactions. Porous storages become more relevant with increasing storage needs.

Emerging technologies

Upcoming technologies currently researched deal with different materials:

- **Metal hydrides:** Hydrogen is adsorbed by metal, which leads to formation of metal hydrides. To free the hydrogen again, the storage needs to be heated. This storage method offers good volumetric capacity, but the storages are heavy. Advantages are the no evaporation losses and the purifying effect of metal.
- **Liquid organic hydrogen carriers (LOHC):** This method applies the chemical bond of hydrogen molecules to the liquid carrier material through a catalytic reaction. Hydrogen is stored in a non-molecular form. Advantages are the high storage density and easy handling and transportation in diesel-tanks¹⁶.
- **Nano-structures:** Building nanostructured porous materials from metallic organic compounds, vast amount of hydrogen can be stored in high densities. One of the main challenges is to find a material which has a controllable hydrogen affinity whilst being able to store and release hydrogen in a short time.

Impact of hydrogen based flexibilities on decarbonisation of the gas grid

Hydrogen feed-in into the gas grid, generated via power-to-gas from renewable energy sources, is one option for the decarbonisation of the gas grid. Hydrogen can be injected directly into the existing gas grid up to a level of about 0-12% depending on country specific standards and regulation (Newton, 2014)¹⁷. Large-scale feed-in of hydrogen into the transmission gas grid requires additional compression of the generated hydrogen to 60 bar. Feed-in in distribution gas grids which are operated with 5 to 10 bar does not require additional compression (ENEA consulting, 2016¹⁸). Due to the high interconnectivity of the European gas grid, methane can be fed into the gas grid at basically every point with limited gas infrastructure expansion needs. Hydrogen can be fed into the gas grid without restrictions if the hydrogen is converted to methane, so called “carbon-free gas”, in a methanation process (named the Sabatier process). The CO₂ needed for the process can be provided from biogas, fossil power plants or from carbon capture technologies. There are already experiments in the EU that test this process, like the one of Stedin in Rozenburg (Stedin, 2014¹⁹). However, this process is

¹⁶ For more information, see <http://www.hydrogenious.net>

¹⁷ Newton, J. (2014): Power-to-Gas and Methanation – pathways to a 'Hydrogen Economy', in: 14th annual APGTF Workshop, London, 2014, ITM Power

¹⁸ ENEA consulting (2016): “The potential of power-to-gas - Technology review and economic potential assessment”

¹⁹ For more information see: <https://www.stedin.net/over-stedin/pers-en-media/persberichten/powerogas-officieel-gepend-elektriciteit-wordt-aardgas-in-rozenburg>

still far away for large scale deployment as the price for natural gas is still low and cost for hydrogen are high.

Another idea is to transport 100% hydrogen gas within the existing gas grid. This would require one conversion step less compared to the methanation process but would require extra investments in the gas grid and for consumer appliances. There are no existing examples of a 100% hydrogen grid that is used within the urban environment. Leeds is seriously investigating the options for a hydrogen grid (Northern Gas Networks, 2017²⁰).

Contribution of hydrogen based flexibilities for the energy transition

A decarbonised gas grid enables the opportunity to use carbon-free gas in the existing connected gas power plants. Excess electricity can thus be stored via electrolysis and methanation in the gas grid and the stored energy can be used in power plants for electricity generation. This process chain is called power-to-gas-to-power.

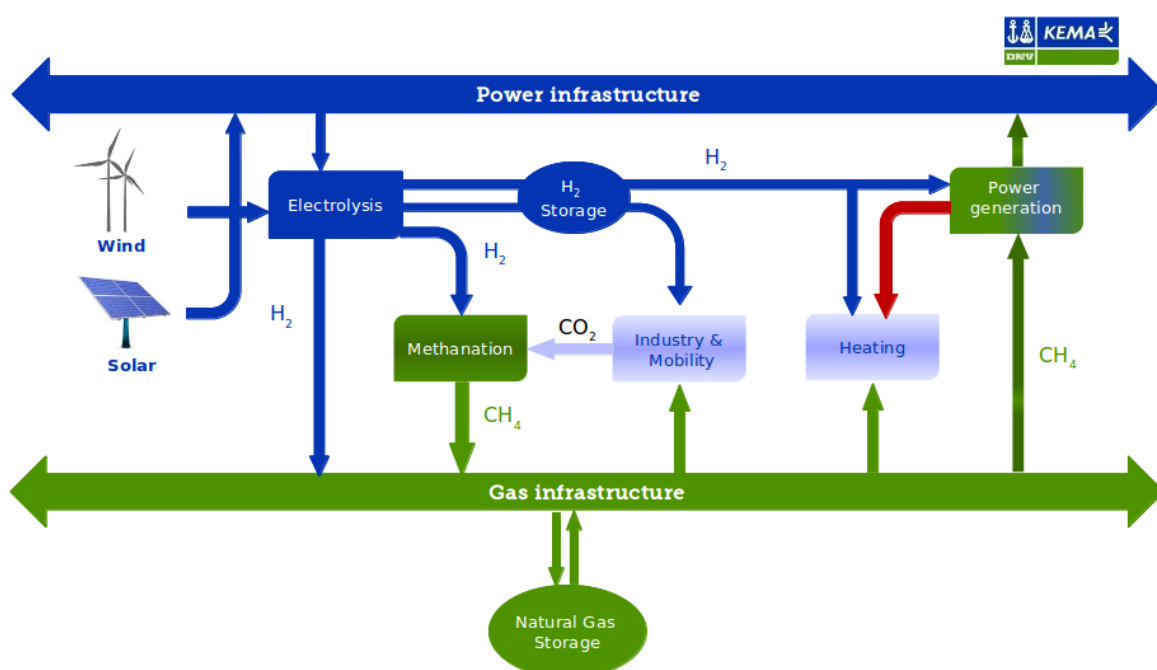


Figure 9: Linking the power and the gas infrastructure via hydrogen (European Power to Gas Platform, 2017)

Figure 9 illustrates the interactions of the power infrastructure and the gas infrastructure related to hydrogen. Electricity is stored in the gas grid via electrolysis and methanation. "Carbon-free gas" from the gas grid can be used in the industry and mobility sector, for heating and for power generation.

The benefits along with the power-to-gas-to-power process are:

- **Seasonal energy storage:** The gas grid offers seasonal storage capacities. The natural gas grid with the connected gas storages is the biggest existing energy storage.
- **Increase in system flexibility:** The decarbonisation of the power sector leads to a long-term phase out of conventional power plants. Gas power plants are considered by some as a transition technology. With the decarbonisation of the gas grid, gas

²⁰<https://www.northerngasnetworks.co.uk/2017/04/27/northern-gas-networks-hydrogen-project-takes-step-forward-as-25-million-fund-announced-for-hydrogen-in-homes/>

power plants could be operated based on carbon-free gas from renewable energy sources and could take a leading role in central flexibility supply for system balancing.

- **Energy transmission:** The increase in intermittent renewable energy generation requires higher interregional exchanges. Power transmission capacities are limited and grid congestion is a burden for renewable energy integration, thereby increases system cost. Gas transmission capacities in Europe are usually greater than power transmission capacities and could help temporarily to reduce power grid congestion. In the long-term, a comprehensive transmission system planning approach for gas and power infrastructure could make use of the gas transmission capacities to transport large quantities of energy within Europe.

However, the process power-to-gas-to-power has high energy losses. In addition to the losses of the hydrogen generation via electrolysis, losses arise in power generation where current large-scale gas power plants reach efficiencies of up to 60% (combined cycle gas power plants) with possibilities to only slight increases up to 64% projected for 2030 (IEA 2010²¹). Efficient centralised gas CHP plants reach higher combined efficiency for the electricity and heat supply, but have a lower electric efficiency.

Specific key regions

This section analyses regions in Europe where carbon-free production of hydrogen is possible due to local overproduction of renewables, which today may suffer from curtailment. The excess carbon-free electricity could feed a power-to-hydrogen facility. The section also deals with possible locations of H₂ demand in Europe, specifically in relation to the industry, the mobility sectors and the natural gas network. The industry sector could in the coming years replace its hydrogen demand produced with an SMR with hydrogen produced with renewable energy. For the mobility sector, the carbon fuel driven vehicles will be partly replaced by electric vehicles and hydrogen fuel-cell powered vehicles due to the regulations in the EU Member States, such as in France where in Paris from 2030 Diesel and petrol vehicles will be banned.

Regions where Carbon-free Production of Hydrogen is possible

Access to cheap carbon-free electricity is a key factor to profit from the production of carbon-free hydrogen with an electrolyser. This can be obtained by accessing curtailed renewable energy due to oversupply in cases of high wind or solar production. In such conditions the wholesale markets experience very lower prices or even negative prices. Due to the strong learning effects experienced already today, a local renewable source can need low CAPEX investments and of course very low OPEX. It was confirmed by the results of a study performed by Tractebel and Hinić for FCH-JU, being regarding the early business cases for hydrogen. The study assessed geographical locations where there were bottlenecks or an excess of renewable electricity. The study identified electricity costs at a level of 40% of the electricity market price at times of oversupply in specific regions. This cheap electricity could be used to make carbon-free hydrogen competitive. Also by providing grid services in the form of frequency control, to the power system, a hydrogen project could improve its financial performance.

The focus of the key regions is on Germany, France, Great-Britain and Denmark. The Tractebel-Hinić study for the year 2017-2025 identified the following renewables annual production yields for these countries:

²¹ IEA (2010): "Technology brief E02 - Gas-fired power", Energy Technology Systems Analysis Programme

GWh (% renewables Germany national production)	France	Great Britain	Denmark
2017	2124 (1.8%)	104 (0.3%)	660 (1.1%)
2025	1702 (0.9%)	464 (0.6%)	2108 (2.1%)

Table 6: Annual curtailment per country (absolute in share in total renewables electricity production)

As shown in Table 6, the greatest potentials lie in Germany and Denmark in 2017, with more than 2000 GWh yearly curtailment. The most promising areas for these countries with the highest share in curtailment are:

GWh (% renewables national production)	Germany	France	Great-Britain	Denmark
	Herrenwyk	Albi	Iverarnan & Tongland	Trige
2017	428 (34%, 59% hours/year)	24 (12%, 9% of hours/year)	71 (20%, 34% of hours/year)	89 (2.5%, 5% of hours/year)
2025	475 (40%, 43% hours/year)	72 (20%, 15% hours/year)	117 (20%, 35% pf hours/year)	442 (13%, 23% of hours/year)

Table 7: Recommended areas for electrolyser installation based on the renewables curtailment in that area

As shown in Table 7, for 2017 the greatest potential lies in Germany and Great-Britain, where high full load hours for the electrolyser are possible, combined with a high renewables share being curtailed. In 2025, also France and Denmark increase their potential.

Germany

The key region in Germany is Herrenwyk, which is in the North of Germany. This region has the highest curtailment in Germany due to high levels of onshore wind energy. For 2025, there are plans for grid reinforcements, HVDC lines from North to South, which will limit the increase of curtailment, as can be seen in Table 6 and Table 7.

In the year 2015, 3500 MW onshore wind was added in Northern Germany, increasing significantly the renewables curtailment in the last few years. One of the goals of the Energiewende (the German Energy Transition strategy) is that by 2050 Germany should ensure that 80% of the electricity is provided by renewables. In case that the grid is not greatly reinforced, power to hydrogen could become very important for 2050.

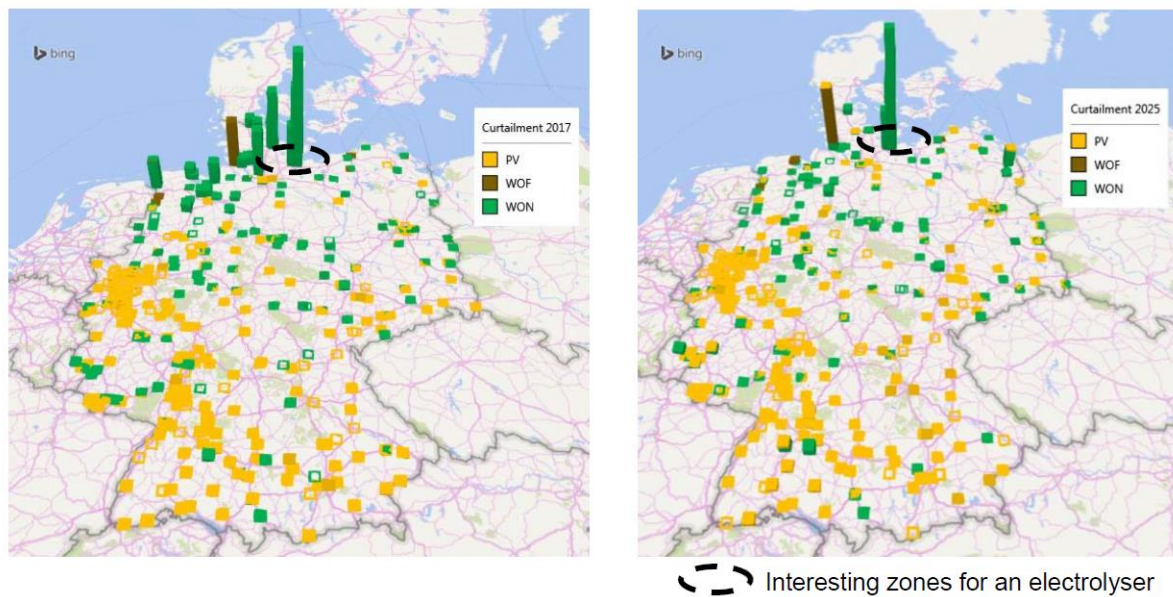


Figure 10: Annual curtailment per renewable technology in Germany (maximum height bar is 475 GWh) [28]

France

The key region in France is Albi, with a rather limited curtailment that will slightly increase in 2025. In Albi onshore wind has the highest curtailment in France. Curtailment is high during spring and autumn, due to strong winds (autumn) and lower electricity demand (spring), driven by a lower electric heating demand.

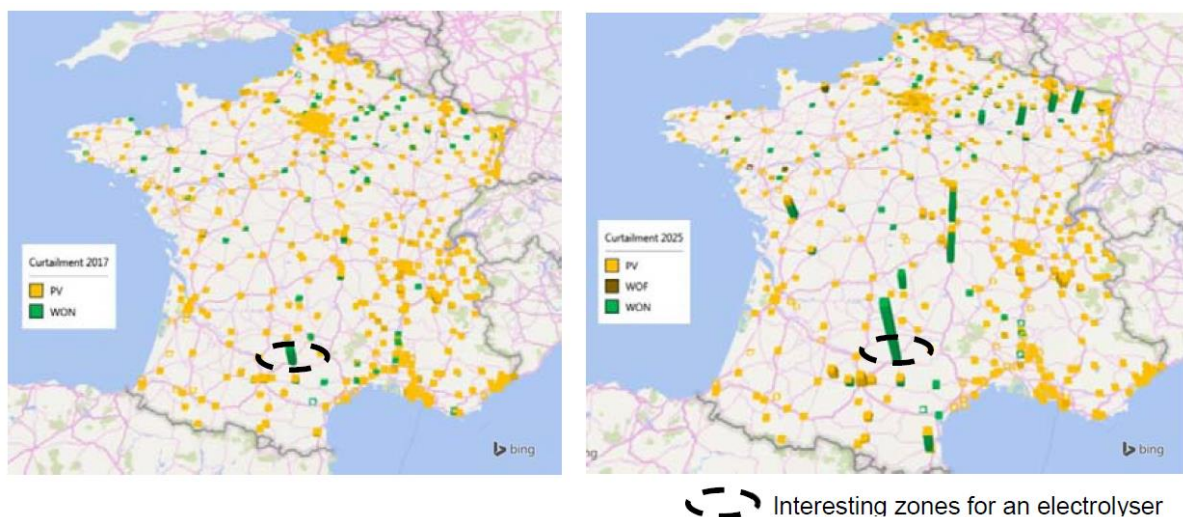


Figure 11: Annual curtailment per renewable technology in France (maximum height bar is 72 GWh) [28]

Great Britain

Tongland (2017) and Iverarnan (2025) are the key regions of Great Britain, located in Scotland, suffering from onshore wind curtailment. For 2025, 1 GW of additional wind power will be added in Scotland. In general, most of the renewables curtailment concerns onshore wind production in Scotland.

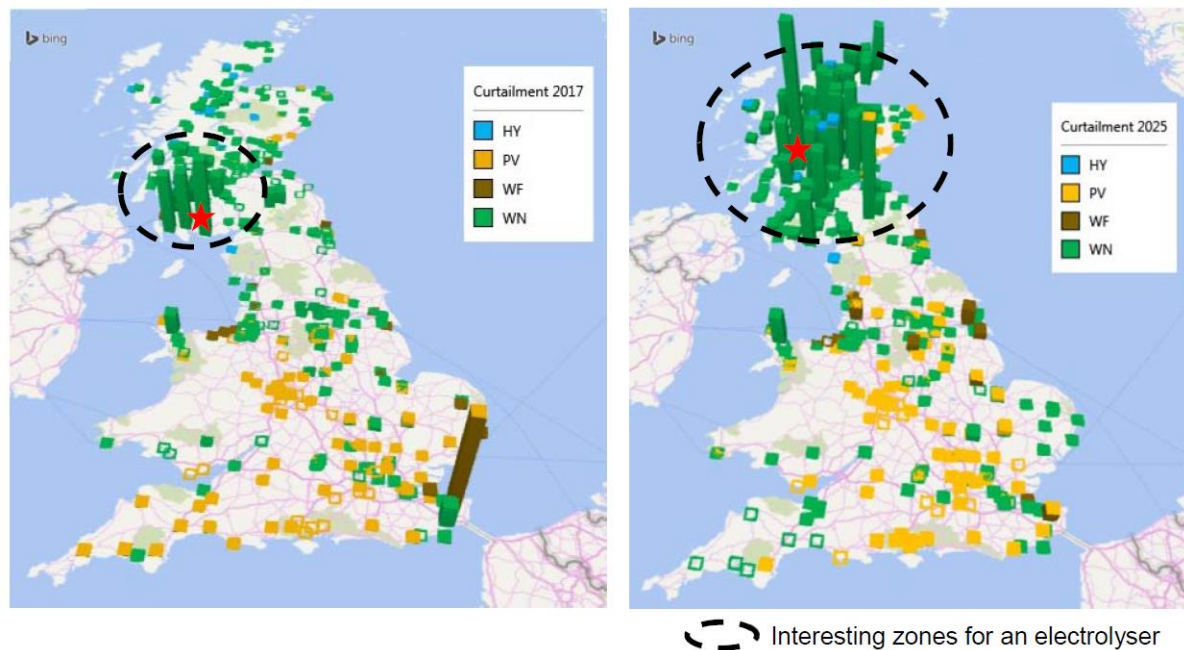


Figure 12: Annual curtailment per renewable technology in Great Britain (maximum height bar is 117 GWh) [28]

High curtailment occurs in the South near Canterbury and concerns offshore wind farms. This curtailment is expected to decrease by 2025 thanks to the NEMO project, which is an HVDC interconnection with Belgium.

Denmark

The key region for Denmark is Trige, which suffers from high offshore wind curtailment. There is quite high curtailment of onshore wind production in West Denmark and offshore wind curtailment in central Denmark.

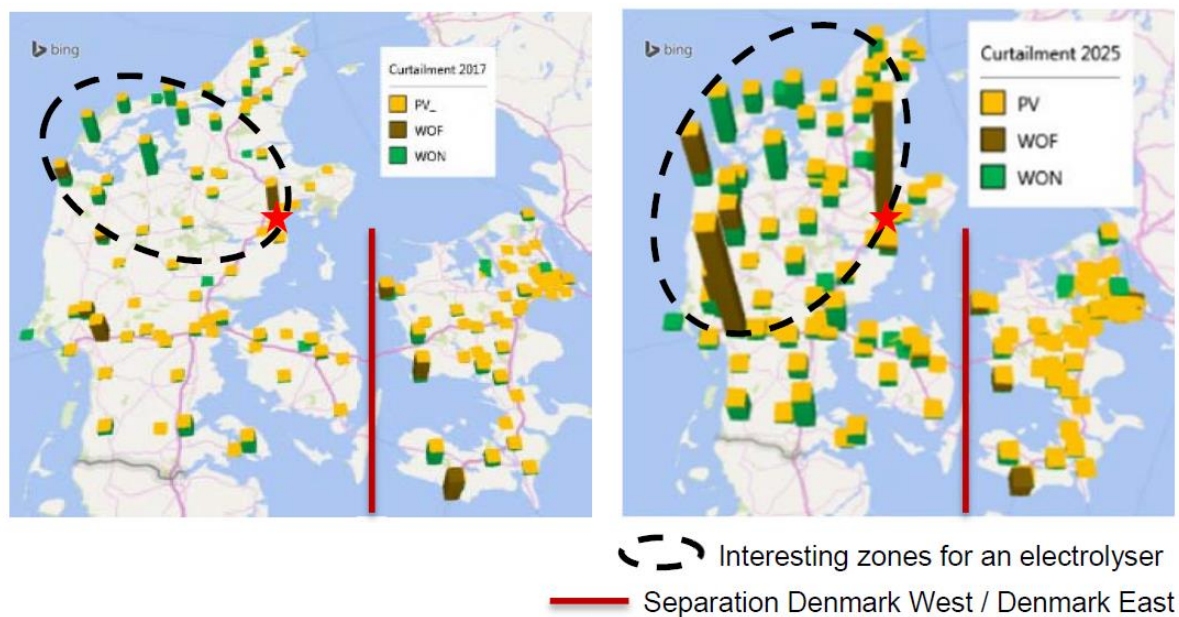


Figure 13: Annual curtailment per renewable technology in Denmark (maximum height bar is 442 GWh)

Regions with industrial demand for carbon-free hydrogen

Previous sections dealt with the cement, fertilizer, steel and refining industries regarding the possibilities of hydrogen use and identified key limitations of a technical and economic nature. Carbon-free hydrogen is nevertheless already used in some industrial projects and further demand growth is expected in the four key regions identified above.

Projects that already use carbon-free hydrogen

- **GrInHy:** With high-temperature electrolysis providing a higher overall efficiency of 80% HHV, a 150 kW solid oxide reversible electrolyser was installed providing hydrogen to steel industry for surface treatment. It has been operational since beginning of October 2017. This was done in the framework of the H2020 program and the project started in 2015. [34]
- **H2Future:** This project plans to install a 6 MW PEM electrolyser for a steel plant in Austria, where the hydrogen will be injected in the coke oven and burned in the plant's power plant. The project also aims to provide grid balancing services. The electrolyser is still under development. This project is part of the H2020 program, and the project started in 2016. [34]
- **Glomfjord, Norway:** From 1953-1991 an ammonia plant used an electrolyser to produce 30,000 Nm³ H₂/h with 168 units of electrolysers by NEL. The installed electricity installation was 135 MW. [35]
- **Rheinland Refinery Complex, Germany (REFHYNE project):** ITM Power has a joint project with Shell to install a 10 MW PEM electrolyser to produce hydrogen at the Rheinland Refinery Complex in Germany, where they consume about 180,000 tons hydrogen per year. [36]

Industries in key regions that have a hydrogen demand

In the four key regions discussed in section 0, it is possible to find industries where carbon-free hydrogen could be part of energy supply.

- **Herrenwyk, Germany:** Near Herrenwyk, there are four refineries in operation in a range of 110 km (Tamoil Holborn - 16.3 ktpa H₂, H&R Ölwerke Schindler, Nynas - 2.5 ktpa H₂, Heide - 29.9 ktpa H₂). Also steel industries can be found, such as ArcelorMittal in Hamburg. Regarding fertilizer plants, the Brunsbüttel ammonia plant can be found at 135 km.
- **Trige, Denmark:** In a range less than 100 km, there is the Fredericia refinery. No data was found about demand for hydrogen in the refinery.
- **Albi, France:** In France, there are 2 fertilizers plants located at about 300 km of Albi, being one in Pardies and the other in Ambès. The ammonia is imported, but it should be possible to produce it on site by making investments in ammonia reactors, nitrogen air separators and of course carbon-free hydrogen production. The marginal cost of onsite production has to be competitive to the cost of importing the ammonia by ship [37], [38].
- **Tolberg - Iverarnan, Great Britain:** No H₂ demanding industry was found near Tolberg or Iverarnan.

Mobility demand for hydrogen

Also in the mobility sector, number of projects using carbon-free hydrogen exist and more are expected to appear with the regulatory incentives being put in place by both national governments and city authorities, such as bans of diesel and petrol cars.

Projects that already use carbon-free hydrogen

- Taxis:
 - Hype taxi fleet in France, which currently counts 50 hydrogen vehicles but plans to increase up to 600 for 2020 [39].
 - Paris-Orly airport: new refuelling station opened on 7 December 2017 by Air Liquide and Groupe ADP with support of FCH JU [39].
 - Hydrogen fuel cell power Black Cab made its debut at 2012 Olympics in London [40]
- Trucks/forklifts
 - Carrefour group, France: Carrefour has purchased 57 Forklifts with fuel cell solution from Plug Power Inc in 2016. Possibly, Carrefour will purchase more than 150 units. This is part of the the HyLIFT-EUROPE project [41] [42].
 - Coop, Switzerland: In Switzerland, the Coop truck company has in collaboration with PowerCell Sweden AB and Swiss hydrogen, for introducing the country's first hydrogen fuel cell truck (350 bar, 31 kg H₂ storage and range of about 400 km) and also the hydrogen refuelling station. In case that tests are successful, Coop intends to replace its entire fleet [43]. The refuelling station will offer hydrogen at both pressure stages (350 and 700 bar) to be able to fuel the hydrogen trucks and 12 fuel cell cars being used by a distribution centre nearby [44].
 - Life 'N Grab Hy, WaterstofNet: Two garbage trucks have been equipped with batteries and fuel cells to be tested in 10 cities, where emissions should be reduced as much as possible [45].
 - H₂ Share, Interreg North-West Europe: A heavy duty H₂ truck of 27 tons is current being designed and will be demonstrated in Belgium, the Netherlands, and Germany. The truck will be refuelled with a mobile refuelling station. The project will run from 2017 to 2020 [46].
- Buses
 - London, UK: Tower Transit buses from London fill their buses in less than 10 minutes at the hydrogen refuelling station by Air Products with hydrogen produced in the Netherlands coming from an SMR [13].
 - Oslo, Norway: Five Ruter fuel cell buses (35 kg H₂ storage) use a refuelling station operated by Air Liquide Norway. The hydrogen is produced by 2 electrolyzers (HySTAT 60), consuming renewable energy [13].
 - Cologne, Germany: Cologne wants to replace its entire bus fleet with alternative powertrains. Four fuel cell buses operate there today. The hydrogen is produced as by-product by chemical processes near Cologne [13].
- Hydrogen refuelling stations
 - Hydrogen Mobility Europe: This is a flagship project where they try to give fuel cell electric vehicles access to a European network of hydrogen refuelling stations. To produce carbon-free hydrogen, also grid balancing value streams were taken into consideration.

- H₂ Mobility, Germany: The establishment of the first 100 refuelling stations by 2018-2019 and in case of an uptake of fuel cell vehicles, this number will be increased to 400 [12] .



Figure 14: Hydrogen refuelling stations across Europe, of which part is funded by H2ME

Mobility in key regions

In the EU there are today a total of 92 public hydrogen refuelling stations. For the key countries discussed in section 0, there are already today several hydrogen refuelling stations installed, as well as near the key regions of each country.

- **Germany:** There were 30 hydrogen refuelling stations in June 2017 [47]. Hamburg, near Herrenwyk (key region of Germany) has three hydrogen refuelling stations today in operation and two in planning.
- **France:** France has about 15 hydrogen refuelling stations. One public station is in Albi, the key region of France, where they provide electricity to EVs and hydrogen at 350 bar, 15 kg per day [48]. By 2040 they will end the sales of gas and diesel powered vehicles. [49] Paris will also ban all petrol and diesel fuelled cars by 2030. [50] This means that by 2030 hydrogen fuelled and electric vehicles will have an important role in the decarbonization of the mobility sector.
- **Great Britain:** Also 15 hydrogen refuelling stations are today in operation in Great Britain and two in Scotland but still at 150-200 km from Ivernarnan and Tongland, the key regions of Great Britain [4]. The UK has also stated that by 2040 sales on gasoline and diesel cars will be banned and by 2050 all cars on the road will need to have zero emissions. [49]
- **Denmark:** Denmark has about 11 hydrogen refuelling stations. There is one refuelling station (700 bar) near Trige in Aarhus (14 km away).

Another interesting hydrogen mobility domain could be the freight truck corridors in Europe, which are the routes trucks take often throughout several Member States. In case the hydrogen truck projects are successful, corridors with hydrogen refuelling stations for trucks could become a reality. A similar project already exists for Liquid

Natural Gas LNG, the LNG Blue Corridors, which is part of a Horizon 2020 programme. [51]

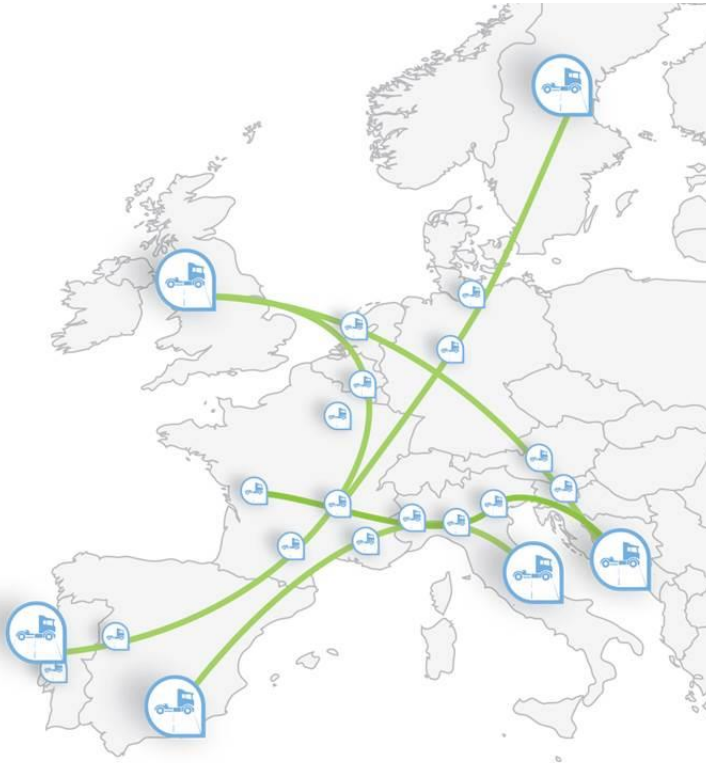


Figure 15: LNG Blue Corridors

Gas grid injection

In the report by Tractebel and Hinicio [28] mentioned above, it was found that gas grid injections of hydrogen can boost cash flows at a low marginal cost. This allows also for continuous electrolyser operation, helping secure revenues for providing grid services and increasing the electrolyser efficiency. In general, no additional investments are needed in the infrastructure of the existing natural gas network. Therefore, it could be an ideal solution for transporting excess of renewables from point A to point B. An example is Germany, with the large excess of renewables in the North. However, there are today technical and regulatory limits for the H₂ injection in the gas grid as well as the fact that hydrogen without support cannot compete with natural gas flowing through the natural gas network. The injection limits are the following for the key countries [28] [52]:

- Germany: 10%vol, 2%vol in case that there is a CNG station downstream
- France: 6%vol
- Great Britain: 0.1%vol
- Denmark: 2%vol

Summary

The aim of this Task was to map different power-to-hydrogen technologies and assess market potential for carbon-free hydrogen. Furthermore, existing barriers to successfully deploy carbon-free hydrogen for different applications were identified.

Additionally, the impact on emissions for the different technologies in these market domains was assessed.

First, the basics of the carbon-free hydrogen production chain were explained, including the electrolyser cost assumptions. The analysis found that the electricity price will be the key factor that will affect the production costs of hydrogen.

Next, the mobility sector was analysed first with focus on hydrogen fuelled vehicles and then in electricity.

For hydrogen-powered vehicles, the analysis focused on assessing the required infrastructure changes for the refuelling stations and the most relevant cost assumptions. It is important to note the difference in refuelling stations for passenger vehicles compared to those for trucks and buses, with the latter requiring one less compression stage. The size of the refuelling station (kg H₂/day), the location of hydrogen production (on-site/off-site), the transportation method of hydrogen and electricity cost are the four key factors impacting the cost of the hydrogen refuelling stations. For the hydrogen-fuelled vehicles, the attention was paid to buses, taxis and passenger vehicles, since these have better market potential compared to the ones for trucks. For buses and taxis, there are more projects in the EU than for passenger vehicles, since central refuelling stations require lower investment costs due to the higher utilization rate. Diesel buses and taxis emit today 118 and 892 g/km CO₂ respectively (tank-to-wheel assessment).

For electrification of the mobility sector, the applicability of electrification of different mobility segments has been discussed. The analysis found that the biggest potential for electrification lies in road transport. The analysis has thus been focused on assessing the options for electrification of cars and trucks. We found that in 2015 already 500 000 electric vehicles were driving on European streets. For trucks, there are pilots for overhead contact line trucks on highways. Similar concepts for buses exist already. To promote electric vehicles, a higher coverage of charging stations is needed. However, existing charging stations suffer low utilisation rates.

The hydrogen demanding heavy industry was also studied. The steel, fertilizer and refinery industries were identified as segments with the highest potential in economically viable use of carbon-free hydrogen. This would require infrastructure installation and changes on site. Steam Methane Reforming (SMR) which is most commonly used for production of hydrogen emits 7.2 kg CO₂/kg H₂.

Next, power-to-heat technologies have been analysed. We found that heat pumps have reached shares of over 20% of total heating demand in some European markets. The use of electricity for heating can support the decarbonisation of the heating sector. The increase electricity demand impacts the power sector. However, we have found that intelligently controlled power-to-heat technologies can have benefits for the power sector. They can improve local integration of renewable energy sources, support system balancing and reduce the required installed capacity of power plants in the long-term. Thermal storage increases the flexibility of heating technologies. Hydrogen can also be used for heat supply. There exist proven technologies as fuel cells that are widely applied in Asian markets. In Europe, fuel cell programmes have led to first installations. The goal is to install 50 000 fuel cells with a subsequent commercial roll-out until 2020.

Different hydrogen storage technologies as energy storages have been analysed. Hydrogen can be stored in decentral tanks under low and high pressure up to 1 000 bar. The main options for central hydrogen storage are salt caverns, porous storages and aquifers. The potential for central storages depends on the geological structures. The impact of hydrogen based flexibilities on the decarbonisation of the gas grid and their contribution for the energy transition have been assessed. The analysis has shown that hydrogen can be injected into the gas grid without restrictions, if hydrogen is converted

to methane. The stored “carbon-free gas” can again be used power generation offering benefits as seasonal storage potential, increased system flexibility and energy transmission capacity.

Finally, key regions were analysed in the following countries: Germany, France, Great Britain, and Denmark, where an excess of renewable electricity exists today and will likely increase by 2025. In these key regions, hydrogen could be cheaply produced. Industry and mobility applications were identified near these key regions to identify possible H₂ demand. Also, EU projects related to H₂ demand for industry mobility were assessed.

Modelling the impact of sectoral integration on the energy system towards 2050

Introduction

This section provides a systems analysis view of the impact of sectoral integration of the energy system towards 2050. In view of the objective to fully decarbonise the energy system, the integration across multiple energy sectors is expected to better adapt to the challenge of achieving the zero emissions goal, while taking full advantage of e.g. the variable renewables, potential exhaustion of resources and ultimately limit the resulting energy system costs.

Roadmaps developed so far continue to have remaining CO₂ emissions in the energy system in 2050, particularly in transport – mineral oils for certain transport modes – and in heating and industrial uses – mainly natural gas. With systems analysis, underpinned by modelling with a novel PRIMES model extension, the present section presents an overview of the options, their advantages and disadvantages from a systems perspective. This approach allows to analyse the interaction between the different energy sectors to better understand and quantify the benefits of sectoral integration.

The scenarios analyse different options based on different developments of technologies. The existing studies are not conclusive about the technico-economic potential of the technologies but agree that massive deployment of the technologies can deliver the potential of learning-by-doing. Therefore, the model projects technology readiness in the future is in the context of alternative scenarios, assuming that market conditions enable massive deployment, which differs per scenario.

The sectoral integration through hydrogen is greatly depending on the assumptions about technology readiness and cost reductions in the future. A successful market deployment requires technological maturity at sufficient degree in all stages of the value chain, involving consumption equipment, distribution systems and production and supply. A possible technological failure in one of the stages of the value chain can make the entire chain inefficient. From a business perspective, the investment and technology provision in each stage of the value chain depend on different actors with different aspirations and activities. Therefore, the market coordination issue is of utmost importance for the overall maturity of the value chain. A successful market coordination can be seen as a positive externality which markets alone may not be able to deliver.

Therefore, public intervention is necessary to help achieving the market coordination in a timely manner. Market coordination failures are quite common in reality when a transformation of technology usage at the end-consumer level requires development of infrastructure and development of the technology at the same time. The sectoral integration cases are precisely of a similar nature. For example, if fuel cells become mature and less costly and similarly if electrolysis becomes competitive, these conditions are not sufficient for a hydrogen market development unless the hydrogen distribution infrastructure develops simultaneously. Market coordination failure also requires coordination of the public policy measures which are applicable to every stage of the value chain. For example, public policies supporting development of hydrogen distribution infrastructure and policies supporting RTD for fuel cells are not sufficient if there is no policy discouraging carbon emissions in the production of hydrogen.

The Appendix includes the background information on power-to-X technologies and the related value chains. They scenarios combine the dynamics of improvement of these technologies with similar developments in end-use equipment and vehicles.

The storylines representing different strategies for sectoral integration assume the context of deep decarbonisation. The focus is on strategies which aim at removing the remaining emissions in the long term as a result of coordinated changes in different energy sectors enabled by the power-to-X technologies. Firstly, stylized and contrasted scenarios are quantified that are helpful to understand the limitations and the advantages of the strategies. Based on this understanding, a balanced scenario is specified and quantified that aims at combining the attractive elements of the stylized cases. A sensitivity analysis regarding technology costs is added to assess the impacts of the uncertainty surrounding technological development. The horizon of the simulations is 2050 and the scenarios build on a basic decarbonisation scenario developed using PRIMES for the Winter Package proposal of the European Commission.

Background: key elements to be considered in the Modelling Task

Features of hydrogen

The sectoral integration based on hydrogen can be seen from various angles depending on the role of hydrogen in the system. The following aspects of hydrogen need to be taken into consideration:

- **Use of hydrogen for chemical storage of electricity**: storage of electricity in the form of hydrogen involves re-electrification of hydrogen mainly in gas turbines or CCGT at an energy efficiency rate of 50%-60%; as electrolysis has an efficiency maximum of 80%, the maximum efficiency of the storage chain is 48%.
- **Use of hydrogen as a feedstock**: it requires blending with CO₂ to transform into syngas which is further upgraded to methane or a liquid hydrocarbon. The technologies are known but the industry has not yet reached the economically efficient scale.
- **Use of hydrogen as an energy carrier**: Direct use of hydrogen in stationary and mobile energy applications can use fuel cells which either operate at high temperature as small scale CHP or lower temperature for mobility. The fuel cells are technically reliable and energy efficient but currently expensive; the learning potential is currently very uncertain. Hydrogen can also burn in equipment which uses natural gas, after adaptations.
- **Storage and transportation of hydrogen**: Hydrogen conditioning is necessary but inefficient for energy consumption. Compressed H₂ can be produced directly from electrolysis with low additional energy losses. Liquefied production of H₂ to transport over long distances would require 20-30% losses in liquefaction. In addition to this, road or rail transport of compressed H₂ is expensive. Pipeline transport of H₂ will need adaptation of the gas pipelines at a significant cost. However, H₂ storage in pressurized tanks and line packs is a practical and economical option. Mass storage of H₂ is possible in underground caverns.

Business drivers for hydrogen

The already published roadmaps for Europe describing energy systems achieving strong emissions reductions until 2050 base decarbonisation on mainly two pillars, renewables and energy efficiency, and use electricity produced from carbon-free sources to reduce emissions in transport and heating. The full decarbonisation of the power sector faces the challenge of balancing large amounts of intermittent renewables. Despite the increasing shares of electricity and the use of biofuels, significant amounts of emissions remain in the system in transport – use of mineral oil fuels in specific transport modes – and in heating and industrial uses – mainly natural gas. System integration and the use of an intermediate energy carrier, such as hydrogen, as a means of storage and

feedstock, can provide a possible solution for the remaining carbon emissions in the energy system and for the maximum use of renewables.

The power system includes increasing amounts of variable renewables and almost all projections see an increasing role of variable renewables in the system. While having considerable benefits in terms of emission reduction, the increased share of variable renewables requires enhanced flexibility of the power system. Among the requirements of the changing power system are: multi-hour fast ramping to balance variable renewables, in particular for solar PV; fast responding dispatchable resources to balance fluctuating renewables; storage beyond a daily cycle to cope with renewables unavailability periods; load shifting on a daily basis to avoid over-generation inefficiencies. Traditional storage technologies have limited potentials: hydro-pumping has limitations due to sites; pure pumping has limited storage capacity and acts mainly as a peak device; compressed air energy storage is expensive and is also subject to siting limitations; batteries are small to medium scale (mostly connected to the distribution grid) and cannot cover multiple-day cycles or seasonal storage. The production of hydrogen from excess power could alleviate the limitations of traditional technologies and provide a flexible storage for excess power and provide balancing capacity. Further hydrogen, besides pure storage, can be used as a fuel directly or act as a feedstock for the production of hydrocarbons for fuel.

The production of excess hydrogen occurs through electrolysis which uses electricity to split water molecules. The hydrogen can then be used for a variety of purposes: it can be mixed with natural gas to reduce its emission factor, it can be burnt directly in gas turbines or motors, or with fuel cells. Fuel cells can be either centralised if it is for feeding electricity back to the grid or decentralised both in stationary as well as in mobile uses. Further hydrogen can be used as a feedstock for the production of hydrocarbons. In the production of methane, after the production of hydrogen through electrolysis, a process called methanation occurs: this process combines the hydrogen with CO₂ to produce methane or with further steps also longer hydrocarbon chains. These can then substitute fossil fuel based fuels for stationary or mobility purposes, with the latter being the most promising (and larger) market. The production of liquid hydrocarbons from the mixture of hydrogen and CO₂ can follow various technological pathways, of which the main are the methanol route and the Fischer-Tropsch route. Integrated co-electrolysis of hydrogen and CO₂ is also an important technology step in the chain producing liquid hydrocarbons. All these technologies are well known in the chemical and oil refining industry. However, they have not reached full economic and technological maturity due to lack of large-scale applications.

Hydrogen is therefore a flexible energy carrier with potential application across all energy sectors; it can:

- compete against direct electricity use in transport and heating depending on the future learning curve of fuel cells
- be injected to the gas grid up to a certain percentage (<15% due to the Wobbe index which is important for the end-use of the gas mix) reducing the average emission factor of distributed gas
- provide feedstock for the production of carbon-free or low-carbon methane or liquid hydrocarbons which can support versatile solutions as they serve as both electricity storage and energy carriers.

However, all hydrogen chains are expensive and require significant developments in order to come closer to market competitiveness. From a technical perspective the processes of hydrogen production and use are known, however significant development is needed in the engineering in order to upscale the processes for economic production and development. The production and usage chains of hydrogen are additionally complex because they require multiple actors of different sectors to interact: this implies that regulation and policy support will be needed and that possibly large players will undertake the investment and the related risks rather than small investors. Even in niche markets where hydrogen is close to techno-economic maturity, hydrogen could

benefit from support in the form of monetary benefits for being emission free. In order for the business case of hydrogen to develop an enabling context for hydrogen needs to be put in place, which includes:

- policy and regulatory certainty, including standards for the security of hydrogen to enhance public acceptance
- support and development of consumer structure
- R&D support

Carbon free hydrogen production

Hydrogen can be produced in various ways: currently the main way of producing hydrogen is through steam reforming from natural gas or oil, however even coal gasification is used to produce hydrogen. However, while these processes are all economically viable and produce hydrogen for industrial purposes, none are carbon free. This implies that because of environmental concerns and under the presence of increasing carbon prices the technology will gradually be driven out of the market. Adding carbon capture and storage equipment to gas steam reforming is expensive and has no sense in the context of a low carbon system, as it is more cost-efficient to produce clean hydrogen instead of searching ways of storing carbon dioxide underground. Carbon capture and use to produce hydrocarbons or in other uses is interesting and important in the course of transition of the system but is of no interest in the long term in the context of a low carbon system, because the chain of carbon dioxide capture and use is not carbon neutral.

Therefore, we need to produce carbon free hydrogen as the first step of any sectoral integration strategy. To produce carbon free hydrogen from electrolysis is the only way, and evidently requires that electricity generation is also carbon free, as electrolysis splits water using electric current.

Three water electrolysis technologies can be considered for hydrogen production: Alkaline Electrolysis Cells (AEC), Proton Exchange Membrane Electrolysis Cells (PEM-EC) and Solid Oxide Electrolysis Cells (SOEC). Because all three technologies are modular, they can apply at a small and at a large scale. The economies of scale are however significant.

Currently the main way to produce electrolytic hydrogen is through Alkaline Electrolysis Cells, however they have limited ability to respond to load changes – essential for the flexibility requirements of the power system, further the design is complex implying limited cost reduction options. The PEM electrolyzers have a simple design and, crucially for the proposed use, are very flexible; they are currently still under demonstration but are assumed to have a very high cost reduction potential. The Solid Oxide Electrolysis Cells apply high temperature electrolysis and are at a very early development stage, thus are expected to develop mainly in the long term. Theoretically the SOEC is a ground-breaking technology due to the very high efficiency, the ability to recover the heat needed to supply the electrolysis and the possibility to operate in reverse mode (regenerative electrolysis). However, the inability to have a flexible load and the high degradation of the membranes imply that this technology is still far from maturity. All electrolysis technologies feature great economies of scale not yet exploited in the industry.

Electrolysers cannot yet compete with steam reforming for hydrogen production economically. However, the use of electrolysers is only limitedly to supply hydrogen as such: their benefit lies in being able to provide balancing and storage capacity for the power generation system where increasing shares of variable renewables require significant flexibility mechanisms.

To further transform hydrogen into hydrocarbons further chemical processes are necessary. The simplest is the methanation which allows for the production of methane gas; this would allow for a full substitution of natural gas with a “clean gas”. The difficulty lies in the supply of CO₂ required, for which several options are available: CO₂ from carbon capture in power and industrial plants – however the process would not be carbon free, but implies shifting of emissions; CO₂ from biomass, in particular biogas – however this would divert limited biomass resources, and it is more efficient to use the biomass directly to produce hydrocarbons; CO₂ from air capture – this is the only way that the gas would effectively be emission free from an accounting perspective but the technology is today immature and expensive.

To produce methane from the mixture of hydrogen and CO₂, the technology with the biggest potential to reach commercial stage is catalytic isothermal methanation. SOEC technology can also directly provide methane in one stack, however it is still far from commercial deployment.

The low overall energy efficiency and the high costs are the limitations of the power-to-liquid processes. The merit is that they can produce fully fungible liquid hydrocarbons using electricity via hydrogen and the conversion of syngas to complex organic molecules. They can provide a petroleum free energy system. They can also lead to zero overall emissions if the power-to-liquid process uses CO₂ captured from ambient air. Two main technological routes are possible, namely the methanol and the Fischer-Tropsch routes. Co-electrolysis of hydrogen and carbon dioxide can also be part of the process.

The technologies of the chains are well known but not yet fully mature at an industrial scale. They can be so if applied to large-scales.

The synergies with Power-to-gas and Power-to-liquids fuels

With regards to power-to-gas technology, methane can be the output of methanation that uses hydrogen and carbon dioxide as inputs. The output which is synthetic gas, is fully substitutable to natural gas that provides great benefits for continuing the use of existing infrastructure of distribution and equipment. Methanation implies a further loss in energy efficiency, reaching an overall rate roughly of 60-65%, including electricity to capture carbon dioxide from ambient air. However, the output can be fully stored and re-electrified in a versatile way. Thermochemical catalytic technologies for methanation are at an advanced stage of deployment.

With regards to power-to-liquids (transport fuels), several technologies are possible, namely:

- Combined electrolysis and carbon dioxide chemical treatment (electro-reduction, co-electrolysis, reverse water gas shift) which produces methanol, dimethyl ether etc. which can be further upgraded to transport fuels (after hydrogenation);
- Fischer-Tropsch conversion of syngas, produced from a treatment of H₂ as an output of electrolysis and CO₂: this can produce hydrocarbon chains of varying lengths (gasoline, kerosene, diesel, etc.)

From a GHG emissions perspective, the origin of CO₂ is a challenging issue. Only CO₂ captured from ambient air guarantees full carbon-free fuels. The overall efficiency rate of the clean liquid chain is between 40-50%.

The techno-economic challenges towards a hydrogen economy

In the traditional bibliography, hydrogen economy refers to an energy system where hydrogen is the main energy carrier in end-use directly. A modern perspective needs to assess which of the hydrogen features (electricity storage, feedstock for hydrocarbons,

direct final use) should be predominant in a carbon free strategy. Higher the share of hydrogen in direct energy uses, lower the extent of electrification in a near zero carbon energy system.

As mentioned above, in the context of a climate strategy, all future roles of hydrogen involve hydrogen production from electrolysis using carbon free electricity as the first stage of the chain. The option of using hydrogen as a feedstock also requires capturing CO₂ from the air to achieve zero carbon emissions.

The hydrogen economy discussion is meaningful only in the context of deep decarbonisation of the energy system, as all technology chains involving hydrogen are energy intensive and produce energy outputs which are significantly more expensive than conventional technologies, even if the cost evaluation included the full learning potential. At full learning potential, a carbon price as low as approximately €100 t/CO₂ would suffice to make synthetic fuels competitive. Without learning, carbon prices above €1000/tCO₂ would be necessary.

The exploitation of learning potential requires large scale installations and massive production; the critical mass to trigger purely private investment is large, and therefore strong policy support is necessary to ensure the initial investments. The upfront investment costs are significant. Purely private investment is surrounded by large uncertainties. Regulation will need to provide clear and long-term certainty about the market prospects of synthetic fuels. The main business model comprises back-to-back long term contracts of synthetic fuels producers and utilities providing clean electricity at a large scale. The economics of large scale power-to-hydrogen (or gas or liquid) production require the uninterrupted and inexpensive supply of carbon free electricity; therefore, extending the necessary interconnections and ensuring fully coupled markets assist cost reductions and risk hedging.

The pathway towards 2050

The basic decarbonisation scenarios developed using PRIMES in 2016-2017 achieve 80-85% CO₂ emissions reduction in 2050 compared to 1990. The reduction in 2050 was similar in the previous Energy and Climate Roadmaps prepared by the European Commission using PRIMES in 2011-2012. In this context, DG-MOVE proposed and quantified a strategy (using PRIMES-TREMOVE) for the transport sector aiming at reducing emissions by 60% in 2050 compared to 1990. Both the White Paper on Transport, published in 2011, and the Communication presented in 2016, confirm the 60% emissions reduction target.

The basic decarbonisation scenarios integrate the emissions reduction strategies of the sectors and thanks to the modelling provide a sectoral integrating strategy, based on the principle of economic efficiency measured as total energy system cost borne by the final end-users of energy. To minimize the total costs for the consumers, the modelling determines an economic equilibrium in the simultaneous energy markets and in the ETS. The sectoral emissions reduction targets derive from this overall least-cost equilibrium.

As it is well known in numerous studies over the last decade²² low carbon emitting power generation is a priority to use electricity as a low carbon carrier to reduce emissions in transport and heating where emissions reduction would be otherwise inflexible. Electrification of road mobility based on plug-in hybrids and pure battery electric vehicles and the wide spread of heat pumps are the main technologies. The emissions reduction strategy also gives priority to energy efficiency in end-use of energy and to renewables. Despite the tremendous transformation required to implement this strategy

²² Including The Role of Electricity, Eurelectric 2008, The Power Choices, Eurelectric 2012-2014, the European Commission's Roadmaps for Energy and the Low Carbon economy of 2011-2012, the Gas Roadmap of Eurogas in 2015

significant amounts of energy-related CO₂ remain unabated in 2050. This is mainly due to the difficulty of electrifying the entirety of stationary and mobile uses of energy. Examples illustrating this difficulty are the sectors of aviation, long-distance travelling vehicles (including trucks) and shipping, as well as special uses of gas in the domestic and industrial sectors, as well as in small scale cogeneration. Even in the power sector emissions reduction cannot go up to 100% in this strategy, as the large requirements of flexibility to balance the increasing production from variable renewables require gas power plants. The carbon capture and storage (CCS) technologies for gas power plants, which are necessary for flexibility and cogeneration of heat, can reduce the ultimately remaining emissions but the reduction cannot go below roughly 90% in a CCS plant.

**Key GHG emissions in Mt CO₂-eq -
EU28 - basic decarbonisation
scenario revised in 2017**

	2005	2050	% change in 2050 from 2005	% structure in 2050
Total	5349.18	1157.45	-78.36	100.00
Energy related CO₂ emissions	4127.13	670.56	-83.75	57.93
Industry	634.05	118.27	-81.35	10.22
<i>of which energy intensive industries</i>	472.23	83.57	-82.30	7.22
Residential	484.16	64.82	-86.61	5.60
Tertiary	271.60	41.37	-84.77	3.57
Services	197.29	24.05	-87.81	2.08
Agriculture	74.31	17.32	-76.69	1.50
Transport	1079.82	360.34	-66.63	31.13
<i>of which Road transport</i>	893.84	243.57	-72.75	21.04
<i>of which Aviation</i>	150.18	101.81	-32.21	8.80
Supply side	1657.50	85.77	-94.83	7.41
Non-energy related CO₂ emissions	282.44	41.23	-85.40	3.56
Total CO₂ emissions	4409.58	711.80	-83.86	61.50
Non-CO₂ GHGs emissions	939.60	445.65	-52.57	38.50

Table 8: Remaining GHG emissions in a basic decarbonisation scenario

The basic decarbonisation scenarios seem to exhaust the possibilities seen from a conventional perspective regarding emissions reduction in 2050. The scenario includes development of bioenergy, including new generation biofuels in transport, but the limitation in the bioenergy feedstock cannot allow biofuels fully substituting mineral oil products. Some amounts of hydrogen and clean methane develop close to 2050 in the power sector as a way of providing storage of electricity and producing carbon free fuels to mix (up to a certain percentage) into gas distribution to reduce average carbon emissions of the distributed gas.

Despite these efforts, the basic decarbonisation scenarios leave 1157 Mt GHG unabated in 2050 of which 671 Mt CO₂ are emissions due to combustion of fossil fuels.

Table 8 illustrates that the supply sectors perform much larger emissions reduction compared to the demand sectors precisely to allow electricity reducing emissions in the demand sectors. The same table shows that the most inflexible sector is transport. More than half of the remaining emissions in 2050 of the energy sector take place in transport, 18% in industry, 16% in the domestic sector and 13% in energy supply.

After a closer look at the remaining emissions, and after the use of biofuels and the hydrogen amounts projected in the basic decarbonisation scenarios, it is evident that to bring emissions to zero it is necessary to substitute mainly liquid hydrocarbons used in transport (134 Mtoe in 2050) and natural gas used in various stationary uses and in power generation (84 Mtoe). Table 9 illustrates these numbers.

Mtoe	Total Solids	Solids in CCS	Total Liquids and transport biofuels	Of which transport biofuels	Total Gas	Of which Clean Gas	Natural Gas in CCS
Industry	1.3		3.2		75.9	37.7	
- rest with emissions	1.3		3.2		38.2		
Buildings	1.2		8.6		75.2	42.3	
- rest with emissions	1.2		8.6		32.9		
Transport	0.0		212.5	99.3	10.5	5.0	
- rest with emissions	0.0		113.2		5.5		
Power and Heat	12.8	12.8	0.3	0.0	64.4	13.8	49.0
- rest with emissions	0.1		0.3		1.6		
Energy Branch	0.1		8.8		7.3	1.3	
- rest with emissions	0.1		8.8		6.0		
Total energy system	15.4	12.8	233.3	99.3	233.2	100.0	49.0
- rest with emissions	2.7		134.0		84.2		

Table 9: Remaining fossil fuels in a basic decarbonisation scenario

The challenge to bring emissions close to zero is due to the climate change mitigation policies at a world level which imply for the OECD countries a very restrictive carbon budget post 2050. The OECD countries will need to achieve near zero carbon emissions in the period 2050-2070 to allow the planet following a 2°C or even more a 1.5°C scenario. It is reasonable to consider that achieving zero emissions after 2050 may imply that important strategic choices are decided early before 2050 which influence the strategy of energy system transition also in the period 2030-2050. Examples are the strategic choices regarding the development of infrastructure and the priorities of the technology policy.

This analysis aims at examining whether further reduction of combustion of fossil fuels beyond the amounts remaining in 2050 in the basic decarbonisation scenario a) is possible, b) how and when it will be achieved and c) at which cost.

In a decarbonisation context, the system must develop in order to be able to deliver zero emissions close to 2050. For the energy system, the highest remaining emission are in the transport sector: some transport modes such as aviation or shipping, as well as a large part of long distance heavy road transportation will continue to use liquid fuels because of lack of alternatives. It is improbable that biofuels will be able to fully cover this residual demand from transport and synthetic fuels based on hydrogen are expected to play an important part in this pathway. Further hydrogen or derived methane gas can also be used to reduce the remaining emissions in industry and in buildings.

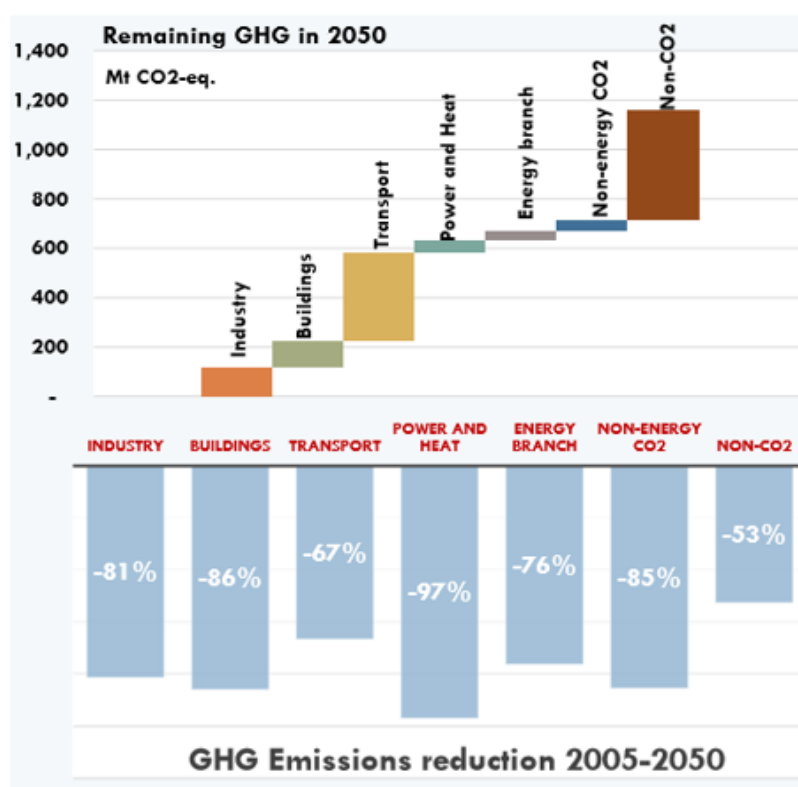


Figure 16: GHG emissions reduction to 2050

Description of the PRIMES model extension

A novel PRIMES model extension has been developed which aims at capturing the market penetrations and future role of synthetic fuels, hydrogen, electricity, heat, steam, chemical storage, carbon dioxide as a feedstock source, as well as the synergies and competition between them. It will have a horizon up to 2070, similarly to the updated main PRIMES model. The model represents the process flow with engineering and economic details. It simulates hourly operation of a system with electricity, hydrogen, gas, heat, steam and synthetic fuels in a synchronised way to be able to analyse storage and finally the benefits deriving from sectoral integration.

The novel PRIMES model extension includes an aggregated representation of the electricity, gas, heat and biomass models of PRIMES integrated into the process flow modelling. It includes an aggregated way fuel choice in the demand sectors, but demand for useful energy is exogenous coming from PRIMES.

It includes alternative pathways for the production of numerous low or zero-carbon energy carriers, such as hydrogen, synthetic methane and synthetic liquid hydrocarbons produced via Power to X (PtX) routes. At the same time, it includes conventional energy carriers such as fossil hydrocarbons, biofuels, electricity, steam, heat, etc. Given the large penetration of variable renewables in the future EU power mix, the need for electricity storage will become more and more prominent. The new module of PRIMES is operating at an hourly resolution and it can capture effectively the operation of large-scale power storage systems. For example, the module determines the hours of the day with excess renewables generation in order to produce energy carriers (e.g. hydrogen) that can be used for the production of electricity later when renewable generation is limited (storage). However, at the same time, the new module is also able to decide whether economics favour the production of synthetic hydrocarbons (using e.g. hydrogen as feedstock) instead of providing storage services. In this way, it captures

- Heat and steam: Produced via heat pumps, boilers, CHPs units, for distributed or on-site consumption.
- Carbon dioxide: Carbon dioxide serves an important role; it acts as the main feedstock source for the production of synthetic hydrocarbons. It can be captured from air or via applying CCU technologies to energy and industrial applications. Only the former though guarantees that the synthetic fuels produced will be carbon neutral (or even providing negative emissions, in case they are combusted in biomass fuelled power plants equipped with CCS technology-BECCS).
- Hydrogen: Carbon-free hydrogen is assumed to be produced via electrolysis running on renewable electricity. It can serve as an energy carrier (either combusted or used in fuel cells in stationary or mobile applications), as feedstock for the production of synthetic fuels, or as a means of storage for balancing the generation of variable renewables. Hydrogen can be transferred via dedicated pipelines (that require investments in infrastructure) or blended in the natural gas stream up to a certain share (15%) due to technical limitations.
- Biofuels (liquid and gaseous) – They are produced using feedstock of biomass origin. The model distinguishes fungible from non-fungible biofuels. The former can fully substitute petroleum products, the latter are blended up to certain shares with fossil based gasoline and diesel because of technical limitations. Upgraded biogas (bio-methane) can be blended to the natural gas stream.
- Synthetic methane – Synthetic CH₄ is an output of a process such as methanation, which utilises hydrogen and carbon dioxide as inputs. The process is energy-intensive, requiring large amounts of electricity. This carrier is usually referred to as “clean gas”, since its net carbon intensity is lower than the one of natural gas, and the pathways to produce it as Power-2-Gas (P2G, PtG). Depending on the origin of CO₂ synthetic methane can be considered even as carbon free, if the CO₂ is captured from ambient air.
- Synthetic liquid hydrocarbons – Usually referred to as Power-2-Liquids (P2L, PtL); such fuels can fully substitute petroleum based products in mobile applications with no radical changes in ICE powertrains. The conventional powertrains continue to run on fuels with characteristics similar to the ones of conventional oil products. Such vehicles exhibit no range limitations and therefore synthetic fuels could be more easily adapted by transport consumers. The competition with the “electrification of the transport system” can hence be assessed by the enhanced PRIMES model characteristics. However, PtL fuels would probably find more room for development in transport modes, where decarbonisation options are limited (aviation, long distances road freight transportation), where they have to compete only with advanced biofuels (with limited domestic resources) and/or technologies that are currently at low TRL levels (e.g. electric aircrafts). Synthetic hydrocarbons are produced in the model with two main pathways whose intermediate products are either syngas (blend of CO and H₂), or alcohols (methanol).
- Electricity Storage – Although technically, not an energy form, power storage is an important element of the new module. Storage can be served either via batteries or via the intermediate step of producing hydrogen and/or synthetic methane for later use. The operation of the module at an hourly resolution allows capturing the appropriate time segments for power injection to storage, and extraction from storage at a later time interval.
- Fossil fuels – serving as conventional energy carriers. Their use results in GHG emissions.

Sectoral integration in the energy system towards 2050: three strategies

In the following we will analyse three strategies which would allow the achievement of near zero emissions by using hydrogen as a means for sectoral integration. The strategies are extreme in their assumptions in order to highlight the benefits and the disadvantages of each. The following chapter then analyses three more realistic scenarios in which the period to 2050 is analysed concretely where options which try to take advantages of the benefits of the analysed strategies, while minimising the disadvantages are constructed.

As stated above the achievement of near zero emissions goes beyond the analyses which have until now been undertaken in the existing roadmaps, which all obtain approx. 80-95% emission reductions in 2050 compared to 1990. The changes required for going beyond 80-95% emission reduction in the period just after 2050 need to start well before 2050, as the technologies and infrastructure required need time to develop as to achieve such deep reduction it is necessary to go beyond technologies mature today. As the developments of these technologies are uncertain and cannot be determined with any certainty today we present three different strategies which allow for the achievement of strong emissions reductions.

The basis for the analysis will be the one of the key scenarios of the Winter Package which is referred as a basic decarbonisation scenario. The context is therefore a framework which achieves the 2030 objectives and further the reduction of emissions by at least 80% in 2050 compared to 1990. The scenario assumes enabling conditions for decarbonisation: this implies that agents act knowing strong emission reductions need to be achieved. Technologies are therefore assumed to develop following positive assumptions on their learning curves and infrastructure developments and market coordination also takes place. The additional condition for the strategies considered here is the requirement to achieve close to zero emissions shortly after 2050.

As the extent of technology and infrastructure development cannot be known, within this study we develop three strategies to explore different options of hydrogen based on different focuses of technology development:

- **Strategy A - H₂ as an energy carrier:** explores the requirements, and the pros and cons of the development of end-use technologies using hydrogen (fuel cells and ICEs) in both stationary and mobile uses, exploring the use of hydrogen as an end-use fuel.
- **Strategy B - H₂ as feedstock** explores the requirements, and the pros and cons of the development of power-to-X technologies exploring the use of hydrogen as an intermediate storage option and to allow for the decarbonisation of all sectors.
- **Strategy C – H₂ as a means of electricity storage** the requirements, and the pros and cons of hydrogen as an enhanced storage option for power generation, accompanied by extreme electrification in all sectors.

All three strategies assume technology success and adequate policy enablers, which differ for each strategy. The following analysis, founded on modelling results of the PRIMES modelling suite, will describe the system requirements and analyse the main uncertainties and key issues to be resolved for each strategy.

Common elements of the strategies

All strategies analysed here require sectoral integration and the use of hydrogen to different degrees.

The first step is therefore the production of carbon-free hydrogen from power: this is projected to occur through electrolysis which achieves market maturity within a medium time frame. A common assumption for all strategies is therefore the need for strong reduction in the costs of electrolysis cells, particularly PEM-cells, already in the period to 2030 for centralized production. Alkaline cells currently have the lowest costs, however their cost reduction potential is more limited as is their ability to operate under flexible load, therefore the strategies base on the assumption that there will be a large diffusion of PEM-electrolysis cells; also SOEC cells have the possibility to strongly reduce their costs, however the current TRL level is approximately 5 (validated technology), and the decrease in cost and their market maturity is assumed to occur too late for applicability within the time period required by climate scenarios to keep within a 2°C world. Alkaline cells are considered to have a TRL level of 9 (industrial production), whereas PEM-cell are at a level of 8, i.e. pre-industrial production.

As shown in Figure 18, the electrolysis production of hydrogen is less costly than gas reforming in a decarbonisation scenario context. Under ultimate learning, the levelized unit costs of hydrogen are of the order of €100/MWh when electricity wholesale sales are at €70/MWh. The economies of scale are small, roughly of the order of 20% ultimately, when comparing centralised production of hydrogen and small scale electrolysis costs on the site of a large refuelling station.

In order for this strong cost reduction to occur, involved actors must anticipate the requirement to decarbonize the energy system, the increasing flexibility requirements, a demand for hydrogen for storage needs, as an energy carrier or feedstock. For this purpose, aside from technological developments, also a regulatory certainty must be perceived by investors, in order to achieve the economies of scale required for the developments. As will be described below, dependent on the strategy such developments need to be anticipated in different time periods.

Levelized unit cost of hydrogen in EUR/MWh of H₂

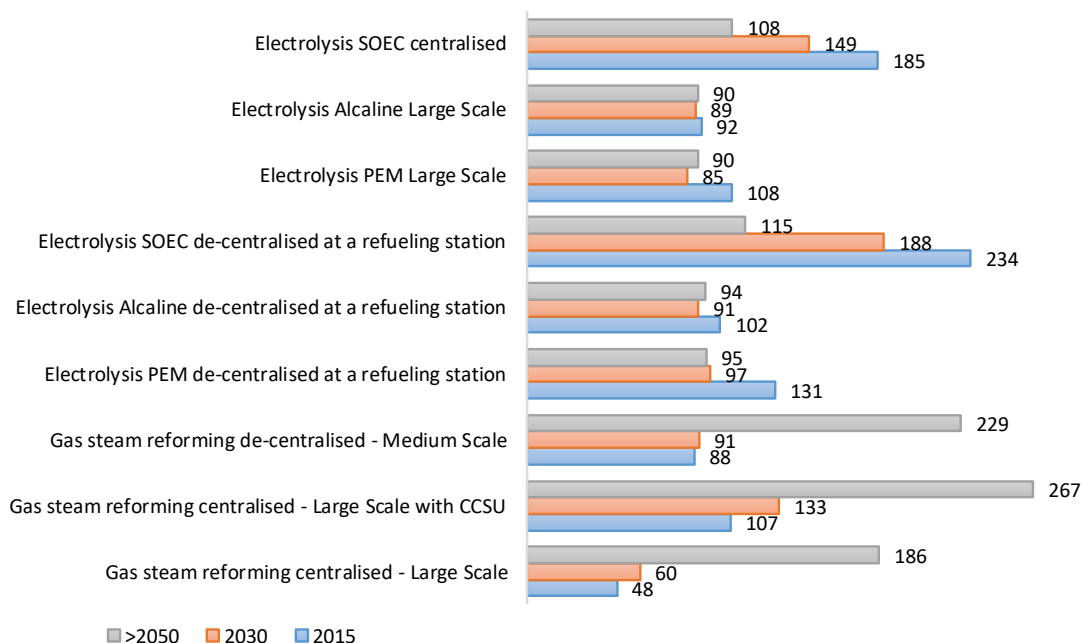


Figure 18: Prospects of production cost of hydrogen in a decarbonisation scenario context

Strategy A: Hydrogen as an energy carrier

This strategy explores the possibility of using hydrogen from power directly in end use sectors. It goes in the direction of what has sometimes been called a “hydrogen economy”.

Strategy requirements: key uncertainties and opportunities

The main idea of this strategy is to produce hydrogen through electrolysis from (mainly) renewable electricity, and use the hydrogen directly in end use sectors which will need to adapt to using hydrogen.

This strategy would require two key issues to be resolved positively:

Development of hydrogen fuel cells: Technological development of fuel cell technologies for stationary and mobile uses (high temperature and low temperature fuel cells), leading to significant cost reductions. While the use of hydrogen would save additional transformation requirements, these developments are far from certain, although there are developments for fuel cells.

Development of a hydrogen transportation and distribution network: the strategy requires the development of hydrogen infrastructure, however the costs for such a development are high. There are several possibilities, however each entail also significant drawbacks:

- Hydrogen conditioning is necessary but inefficient for energy consumption
- Compressed hydrogen can be produced directly from electrolysis with low additional energy losses from PEM-cells
- Producing liquefied hydrogen to transport over long distances implies 30-40% energy losses in liquefaction
- Road or rail transportation of compressed hydrogen is expensive
- Pipeline transport of hydrogen needs new infrastructure or retrofitting of gas pipelines at significant costs
- Hydrogen storage in pressurised tanks and line pack are probably the only practical and economic possibilities

Direct use of hydrogen in stationary and mobile energy applications can use fuel cells which can either operate at high temperature as small-scale CHP units for heating purposes or lower temperature for mobility. Small scale CHP units are required for use in buildings (both residential and services), as well as for industrial purposes. For transport, fuel cells can be used for light duty vehicles as well as heavy duty applications in road transportation. The use of fuel cells is not yet a proven technology for aviation, while use for shipping purposes is possible for short sea shipping and requires further technology development to apply to long distance shipping.

The fuel cells are technically reliable and efficient in energy but are currently expensive; the magnitude of learning potential of fuel cells is uncertain. For this strategy to occur an optimistic view on fuel cell development needs to be taken, in order for fuel cells to become competitive with electric battery powered vehicles. Until today, industry has failed to deliver the promised cost reductions of fuel cells, regularly postponing to the future the achievement of market maturity.

Direct use of hydrogen for combustion in end-uses is possible but technological adaptations of equipment are needed. There exist numerous possible applications of using hydrogen directly in industrial furnaces and kilns.

The use of hydrogen at a large-scale in stationary uses of energy requires a development of a full scale distribution system based on pipelines. Transport of hydrogen by trucks in compressed or liquefied form may be a viable solution for refuelling stations in transport but not for stationary energy uses. Similarly, on-site small scale electrolysis is also not viable for stationary uses of hydrogen except in a few large-scale industries.

The strategy of promoting hydrogen as an energy carrier further requires a timely recognition of the potential cost reductions of fuel cells for transportation and small scale stationary applications, and therefore the timely development of hydrogen infrastructure. The use of pure hydrogen as an energy carrier as this strategy foresees, requires the creation of a dedicated hydrogen transportation and distribution infrastructure for refuelling purposes and for the distribution to the domestic sector and industry. The development of hydrogen infrastructure is a timely and costly issue, which can cause significant disruptions. Hydrogen cannot use the existing natural gas infrastructure, as the current pipeline design would lead to leaking. Developing a new infrastructure to the level required for a substantial substitution of the natural gas infrastructure to allow for a "hydrogen economy" will be complicated. However, if it were to develop a carbon free integrated energy system would develop with a universal energy carrier.

As mentioned, the energy-carrier strategy crucially relies on two elements: the development of fuel cells and the establishment of a hydrogen infrastructure. While the first element requires mainly technical development, the second requires a policy decision to establish such an infrastructure. Obviously such a decision will only take place once there is a relative certainty about the development of fuel cells, however economies of scale for fuel cells can only be achieved once there is certainty of the development of an infrastructure.

The main advantage of this strategy is the adoption of hydrogen which is a universal and flexible fuel which can be applied to all sectors and the maintenance of high energy efficiency thanks to the use of fuel cells (depending on the hydrogen distribution infrastructure chosen).

Changes required in the energy system

A strategy founded on using hydrogen as an energy carrier throughout the energy system requires fundamental changes to the energy system as a whole. In the following we identify the key changes and challenges that would be required in both the demand and supply side sectors.

For the demand side sectors, the changes are substantial for mobility and challenging for the stationary sectors.

The buildings sector would still be expected to undertake all the energy efficiency effort which is projected in a basic decarbonisation scenario context. Almost the entire building stock undertakes energetic renovation until 2050, and a very large share of the buildings stock would rely on heat pumps powered through electricity. However, the remaining buildings using natural gas in a decarbonisation scenario context would be expected to switch to using hydrogen. Initially in such a strategy it would be expected that hydrogen is mixed with natural gas –to its technical limit– in order to lower its emission factor, which would still allow using the same equipment using natural gas. As fuel cells become available (probably close to 2050), equipment would need to be shifted from natural gas condensing boilers, to fuel cell micro-CHPs which would provide steam/heat and also some/all electricity allowing the houses to reach the aim of being nearly zero energy buildings, or even active buildings (Prosumers), possibly even selling electricity to the grid. While the changing of equipment from boilers to fuel cells would probably be to a large extent similar to switching from oil to gas, as has been occurring and is occurring today, the connection to the infrastructure and the switching of the infrastructure is far

from trivial. Constructing a parallel infrastructure to the existing natural gas grid would be extremely costly, however modifying the natural gas grid is also complex: it would require the infrastructure to be shut down temporarily leaving buildings without their main energy source for heating, something which could happen only outside of the heating season or possibly even when the building dwellers were not there. Such a complex change would need very careful planning, however it would allow the building sector to become emission free and there to be some competition between electricity and hydrogen avoiding a mono-fuel solution.

Also industry would be required to undertake the same significant energy efficiency developments as in the decarbonisation scenario context, however extreme electrification would not be necessary in specific industrial processes, which nonetheless cannot cover all applications. The use of high temperature fuel cells with CHP in industry would provide steam of high quality for many industrial uses, however, direct injection of hydrogen is more appropriate for high temperature applications. There is a market scope for clean hydrogen in furnaces, kilns and the blast furnaces, also in calcination and annealing industrial processes. Using hydrogen in these high enthalpy processes presents advantages over electrification. The fuel cells as CHP units can compete for the medium and low enthalpy uses in industry. From an energy efficiency point of view, the optimisation suggests that both electricity and hydrogen keep specific roles and shares in the industrial processes. Full independence from fossil fuels is thus possible in industry.

Carbon-free hydrogen would be readily available for non-energy uses, which today already use hydrogen mainly from steam reforming; this would already significantly reduce emissions from industry. These sectors would benefit from the strong reduction in electrolysis costs, driven by the economies of scale of large scale hydrogen production for the entire energy system.

With fuel cells expected to develop at a large scale only close to 2050, it is reasonable to expect that car electrification will develop earlier in the transport sector, at least as a dominant solution for urban areas. In long-distance travelling vehicles the longer term maturity if fuel cells enable higher competitiveness than the battery-based electrical vehicles. Therefore, the projections expect that fuel cells develop mainly for heavy duty road transportation, coaches and the large vehicles frequently travelling long distance trips. Although the fuel cells and hydrogen tanks are heavy, batteries are still expected to be more problematic for long distance travelling vehicles. If they are facilitated by a sufficient refuelling infrastructure and assuming availability of less expensive fuel cells, the projection shows that fuel cells can gain market shares for private cars in the long term (close to 2050 and beyond) and gradually substitute all kinds of the remaining non-electrified vehicles still relying on liquid fuels. Biofuels would still be required, particularly for aviation purposes and in shipping for bunkers. For short sea shipping fuel cells would slowly penetrate the market and in the longer term also for medium distance travelling ships.

Although fuel cells are very efficient, the production chain from electricity to hydrogen and then the transport and distribution still requires substantial amounts of energy – electricity in this case. Based on modelling results only for the substitution of remaining emitting fuels, electricity consumption would increase by just under 80% in order to achieve zero emissions, if hydrogen were to be used as an energy carrier in the end use sectors directly. An increase of 80% power generation requirements is a further huge change in the power sector.

Strategy B: Hydrogen as feedstock

This strategy explores the consequences of using hydrogen as an intermediate storage option with the development of power-to-X technologies, which would allow to produce fuels chemically equivalent (fungible) to those used today in a carbon free manner.

Strategy requirements: key uncertainties and opportunities

The main idea of this strategy is to produce hydrogen from electricity and use it as a feedstock to produce gas and liquid hydrocarbons which are substitutable to the fuels used today. Such a strategy requires the development of complex power-to-X (X: hydrogen, gas, liquids, heat) factories to supply clean synthetic methane and hydrocarbons which can use the existing distribution infrastructure, while also providing storage to the power system. Electrolysers are required as in all strategies taken into consideration. Fuel cells however are not required and could remain a marginal niche market technology, as is the case today. Hydrogen becomes a feedstock for the production of hydrocarbons (gas and liquids) by combining the hydrogen with carbon dioxide. Obviously, as this strategy only substitutes the origin of the hydrocarbons the distribution systems remain as today. This is the most notable advantage of this strategy.

The hydrogen-feedstock strategy would require the development of power to gas and power to liquid production chains at a large-scale coupled with massive production of clean electricity ideally achieving base-load rates of use.

Power to Gas: Through a process call methanation hydrogen is combined with carbon dioxide to produce methane gas -termed "clean gas": the great advantage of producing methane is that it is fully substitutable with natural gas and can be fed into the existing natural gas distribution network with no technical limitations. It further can be used in stationary uses, exactly as natural gas. As the methane will be a domestic product, the hydrogen-feedstock strategy fully solves the security of supply issues related to dependency on gas imports.

The methanation however implies a further loss of energy efficiency over the lifecycle, getting to an overall rate below 40-50%, but the output can be fully stored and re-electrified in a perfectly versatile way. Thermochemical catalytic technologies for methanation are at an advanced stage of development. The unit costs of methanation are small and reasonable. However, the costs of capturing CO₂ from the air are today high and their reduction through learning is quite uncertain at present.

Power to liquids: Further to the production of clean gas another opportunity is to use the hydrogen as a feedstock for the production of liquid fuels (Power-to-liquid). Several technologies are possible, which can be classified into two groups:

- combined electrolysis and carbon dioxide chemical treatment (electro-reduction, co-electrolysis, reverse water gas shift) which produces methanol, dimethyl ether etc. that are further upgraded to transport fuels after hydrogenation;
- Fischer-Tropsch conversion of syngas, produced from a treatment of H₂ as an output of electrolysis and CO₂.

All technology pathways are energy intensive, however they allow for the continued use of the existing infrastructure and technologies and importantly provide an alternative to excessive production of fuels from bioenergy products, or extreme electrification. As in the case of methanation, the capital costs of power to liquid technologies are reasonable

but the overall energy efficiency of the chain is very poor while the cost of capturing CO₂ from the air is high and uncertain.

The origin of CO₂ is a crucial element to consider for this strategy: only CO₂ captured from ambient air guarantees full carbon-free fuels. This technology is currently at a demonstration level of development (TRL level 6). For the development of such a strategy this technology needs to become a mature technology by following a steep learning curve before 2050. Using CO₂ captured from fossil burning power plants (CCU), reduces but cannot eliminate CO₂ emissions, as the CO₂ is simply emitted at a different place (in car exhaust fumes rather than by the power plants directly), and CC technology only has a maximal capture efficiency of approx. 90%. For this reason, CO₂ captured from power plants cannot be considered an option to reach near zero emissions.

From a technical point of view therefore crucial developments required for such a strategy are:

- The development of CO₂ capture from ambient air
- Development of combined electrolysis and carbon dioxide chemical treatment technologies
- Or alternatively the development of large scale Fischer-Tropsch

The latter in particular can benefit from the developments in the biofuel industry, where F-T synthesis is also a crucial technology for the production of lignocellulosic fuels.

The use of hydrogen as a feedstock combined with CO₂ capture from air is able to produce emission free fuels (at a cycle level) which are fully substitutable to the fuel currently used, which implies they can be used in the current infrastructure and with current technologies.

Levelized unit cost of methane in EUR/MWh of CH₄

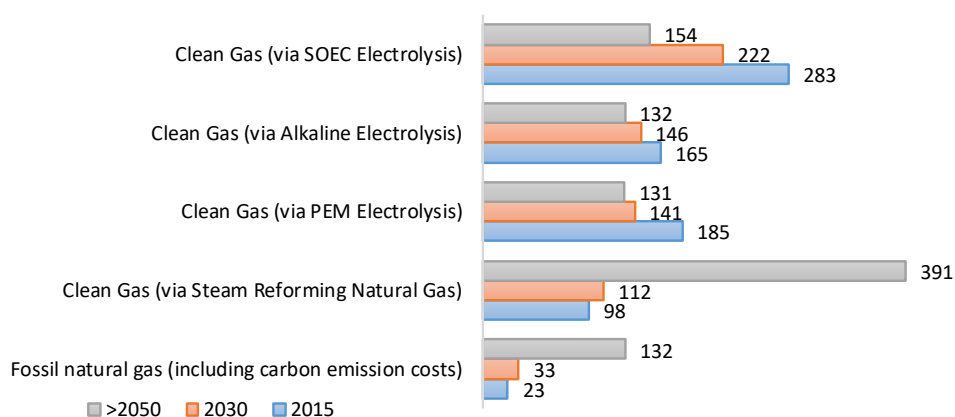


Figure 19: Prospects for clean gas costs in a decarbonisation scenario context

The produced fuels should be used to fully decarbonize the industrial and buildings sectors through the clean gas, although direct electrification and energy efficiency should continue to be the keys means of decarbonisation. For the transport sector electrification of LDVs is assumed to occur nonetheless, but the difficult to electrify transport modes, aviation, shipping, and long-distance freight road transport are assumed to continue using liquid fuels however produced via power to liquid, limiting the use of excessive biofuels.

Levelized unit cost of diesel in EUR/lit of diesel

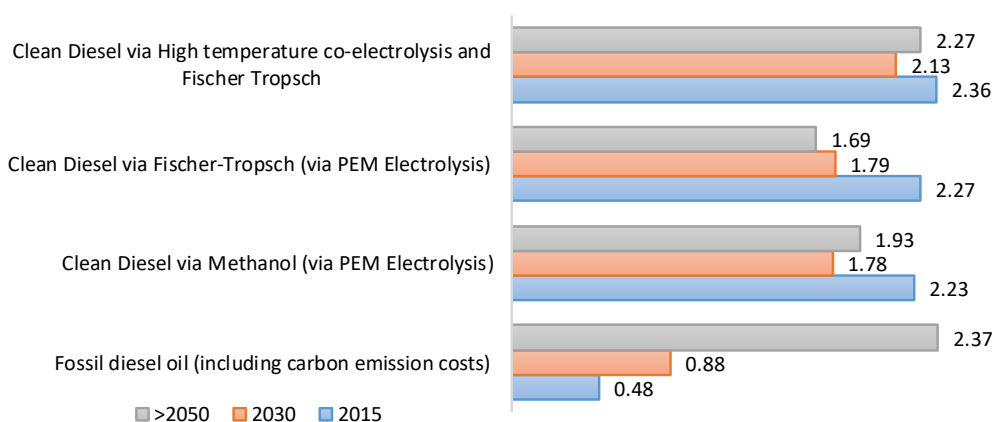


Figure 20: Prospects for clean liquid fuel costs in a decarbonisation scenario context

The Figure 19 shows the projected unit cost of clean gas in a decarbonisation scenario context. Assuming full learning of the technologies and exploitation of economies to scale, the unit cost of clean gas production can reach a level which is comparable to the unit cost of natural gas in 2050 provided that an adequate carbon price (above €100/tCO₂) penalises the cost of natural gas. This is remarkable, as it shows that in a decarbonisation scenario context there exist an affordable full-scale substitution of the remaining amounts of natural gas which at the same time solves the issue of the remaining emissions from the fossil natural gas and eliminates any threat on security of supply stemming from dependence on gas imports.

The Figure 20 shows that the economic competitiveness of clean diesel compared to fossil diesel is also possible in a decarbonisation scenario context provided that a high carbon price penalises the unit cost of fossil diesel. There is uncertainty regarding the winning power-to-liquid technology, but the projection shows that the Fischer-Tropsch route using PEM electrolysis seems to achieve the lowest costs among the competing technologies. The main uncertainty regards the future costs of the SOEC electrolysis which can support the high temperature power-to-liquid route, which for some authors could be the most promising in the future.

The production chain of clean liquid gas and fuels is very inefficient from an energy perspective and therefore the additional electricity requirements are enormous. The projections show that the power generation system will need to increase between 130-170% post 2050 (compared to 2030) to produce clean gas and liquid fuels to fully substitute the fuels remaining in use in the context of a decarbonisation scenario. By assuming such a context, it is evident that the amounts of fossil fuels (gas and liquids) remaining in use by 2050 are the minimum possible. Despite this, the projected increase in the power system size is still enormous to substitute all remaining fuels by clean ones. Obviously, such an increase in the size of the power system is challenging for the power generation resources (including the renewables) and the grids. Large-scale new grid developments are necessary to link with remote areas and transfer additional amounts of renewables. Nuclear can find a favourable business case to develop (much above current levels) provided that there exist nuclear sites and appropriate acceptance conditions.

Such a strategy assumes that there is strong policy support for the production of synthetic-clean fuels which provides regulatory certainty for large scale investors. It must be assumed that long term contracts between clean electricity suppliers and fuel

production facilities are facilitated which provide certainty to both investors. This strategy requires strong coordination from actors across, implying that coordination failure is one of the key risks of this strategy.

Changes required in the energy system

A strategy founded on using hydrogen as a feedstock to produce the gas and liquid hydrocarbons fully substitutable to the fuels used today requires significant changes to the supply side sectors (power generation and fuel production), while requiring much more limited changes in the demand side sectors.

For the demand side sectors changes beyond those assumed within a basic decarbonisation scenario context are limited. Due to the very low efficiency of the production chain of the synthetic fuels assumed to be produced, their use should be limited by energy efficiency and electrification; however, their availability implies that electrification does not need to go beyond technically and economically feasible cases.

Buildings in such a context should, as in the case in the basic decarbonisation scenario context, undergo strong renovation in order to achieve significant improvements in terms of energy efficiency, reducing the consumption of buildings substantially. Further electrification by use of heat pumps should continue to make significant insights. The then remaining use of hydrocarbon fuels (mainly natural gas) could continue to occur, without any changes to end-use equipment or infrastructure as the clean gas produced would be chemically fully equivalent to the current natural gas, excluding any impurities.

For industry, the possibility of using fuels which have no emissions on a life cycle basis, but are chemically equivalent to today would entail significant simplifications from today's perspective. The hydrogen required for non-energy uses could still be produced in a carbon-free way, as the electrolyzers are assumed to develop anyhow in this scenario. As is the case for buildings, energy efficiency would still be required to the extreme as the power-to-X fuels are very inefficient from a system's perspective; however, the availability of the "carbon free" fuels do not require extreme changes in some production chains. Some production changes, e.g. glass production, where a shift to electricity would cause changes in the glass composition, would greatly benefit from the availability of power-to-X fuels.

The transport sector and indirectly the biofuel sector (and all its production chain) would be the main "beneficiaries" from the availability of power-to-X fuels. Again, because of the inefficiency in the production of power-to-X fuels and therefore their high end-user cost, the transport sector would still be required to undergo all the changes towards electrification which are projected in the decarbonisation scenario context. For private road transportation battery electric vehicles would remain the key technology, as well as for urban transportation (freight LDVs, etc.). Power-to-X fuels would enter the market along-side fungible biofuels allowing the transport sector to fully decarbonise without needing to rely on either very uncertain (from today's perspective) technological developments such as fuel cells (strategy A) or electric aviation (strategy C), or on the excessive use of biofuels, which may lead to sustainability issues.

While the proposed strategy of using hydrogen as a feedstock to produce fuels fully substitutable with today's fossil produced fuels, limits the required changes to the demand side sectors to those projected for the decarbonisation scenario context which does not achieve near zero emissions, the changes required on the supply side are immense.

For the production of the power-to-X fuels an entire new production chain needs to be put in place. Large scale factories linked to electrolyzers and power producers need to be constructed which transform power to hydrogen to hydrocarbons. These are entirely new facilities with to a large extent new technologies only used at small scale facilities

today. The facilities would need to be placed where the electrolyzers are in order to avoid requirements to transport the intermediate product hydrogen; the electrolyzers would most probably be placed at the landing points of large DC transmission lines. If these places correspond to current industrial sites or new industrial sites entirely would need to be constructed, is not the focus of this study, it should however be taken into consideration for further assessments, as this could have issues with public acceptance, could however on the other hand also provide considerable employment.

Aside from the huge construction requirements for the facilities to produce the power-to-X fuels, enormous additional power generation capacity is needed, as mentioned above. The inefficiencies of the fuel production, due to the numerous transformation processes, imply enormous additional electricity requirements.

An increase between 130-170% post 2050 (compared to 2030) in the size of the power sector of Europe to produce the clean fuels using hydrogen feedstock in a decarbonisation scenario context requires significant increase in renewables and nuclear energy. The possible increases in renewables (above the levels projected in the main decarbonisation scenario for 2050 and beyond) are mainly from offshore wind located in remote areas (North Sea) and by using the floating wind offshore technology, as well as from the development of very small scale roof top wind. Increase in installations of wave energy are also possible in this context. The development of solar and traditional onshore wind energy above the levels of the basic decarbonisation scenario is less likely. Nuclear may increase up to 50% the installed power capacity compared to present levels. This is an important contribution to ensuring adequate supply of electricity in the context of production of clean gas and fuels. Obviously, the additional power sector developments would require additional interconnections, including reinforcement of DC super-grids needed to integrate the large-scale wind offshore production.

Strategy C: Hydrogen for power storage

This strategy focuses on the use of hydrogen for power storage only and consequently presumes large scale electrification in all sectors.

Strategy requirements: key uncertainties and opportunities

Electrification is the key word of this strategy: electricity substitutes all other energy carriers at a consumer level, as much as current and future technology permit. The domestic sector is entirely electrified and the same occurs with industry, where bioenergy is used in the rare cases where electricity cannot be used technically. In the transport sector also road electrification is developed to the extreme including technologies for electric trucks (as for example the overhead lines in motorways). Even short distance electric aircrafts need to be included among the electrification options in transport.

Nonetheless, this strategy requires a modest increase in demand for electricity compared to the basic decarbonisation scenario. The increase in demand for electricity is of the order of 20-30%, which is far less than in the case of using electricity to produce the hydrogen carrier or even worse the clean synthetic gas and fuels.

To minimize electricity price and maximise reliability it is important to complement the electrification of end-uses with large-scale electricity storage. This is important also to balance the large amounts of variable renewables developed due to the requirement of zero emissions electricity, but also to smooth the load curves, which inevitably would suffer from higher volatility as electricity penetrates in all end-uses of energy. Electricity storage is of higher importance in the maximum electrification scenarios than in the previous cases based on hydrogen-carrier or hydrogen-feedstock. Large-scale storage of electricity is also important for security of supply as electricity becomes the only

source of energy for the consumers and all transport modes, and so higher levels of reliability than usually need to be established in the system. Here comes the role of hydrogen produced from electrolysis as a perfect and versatile electricity storage system. The reliability of storage based on hydrogen, similarly to any kind of chemical storage of electricity, is much higher than with other means that require short cycles of charging and discharging or do not present the flexibility of scheduling charging and discharging as the hydrogen systems. Higher reliability of storage implies higher reliability of the power supply which is a must in the full electrification case, as already mentioned. However, the projections do envisage significant development of the decentralised storage based on batteries both at the scale of the individual consumer and within the substations of the distribution system.

In the end-uses of energy, the hydrogen-storage strategy requires the development of electric end-use technologies in all applications, which is far from certain from today's perspective. For transportation extreme technical solutions are required to fully electrify: electric airplanes are being prototyped for very short distance and small airplanes. There is obviously competition between short distance aviation and high speed railways. Biofuels would be utilised in such a strategy for all uses where electrification is impossible, however this will go to the limits of sustainable biofuel production.

A strategy which uses hydrogen as storage for power and plans to electrify to the extreme demand side sectors could initially be seen as a "simpler" solution to the problem. From the power side this is indeed probably the case however not for the demand side. For the demand side sectors, the technology requirements are significantly more complex as not all uses are electrifiable with technologies known today. Several industrial processes are very difficult to electrify and technologies are sparse, the quality of the output is affected and the production process might have to be altered. For the domestic sector electrification is theoretically possible without major drawbacks. For the transport sector however the situation is different: there will continue to be modes of transport which cannot be electrified. Private road transport can be electrified to a huge extent, however freight road transportation over long distances is very problematic to electrify, as is aviation. For the purposes of a full electrification strategy even technological solutions such as electric planes (small planes for short distances) need to be considered.

Changes required in the energy system

While the hydrogen-feedstock and hydrogen-carrier strategies provided a "simpler" solution for the demand side sectors and a more complex transformation of the supply side, the strategy which uses hydrogen only for power storage purposes implies considerable changes in the demand side that are challenging particularly from a technical point of view.

For the demand side sectors extreme technical solutions are required to allow for full electrification.

For the domestic sector this strategy is challenging but not to the extreme: there are few uses in the tertiary sector where electrification is complex and there may be some public acceptance issues for niche markets or users, but heating uses can be mostly electrified without major technical issues. Energy efficiency and renovation obviously need to continue to the extent possible in order to minimise the additional electricity needs.

For the industrial sectors electrifying all uses is a complex issue. While again the non-energy use of hydrogen can be catered for as also this strategy requires the development of electrolyzers, other issues are challenging. Some industrial processes such as glass production require the modification of the composition of glass in order to

work; processes based on chemical reactions at high temperature (kilns, blast furnace) and others require development of new technologies to fully electrify. While some actors in the industry are trying to adapt to these challenges, it remains unclear in what time scales technical solutions can be found. Steam production at the steam quality requirements for some industrial process requires very high temperatures which imply very high electricity consumption which would need to be supplied at low costs.

The transport sector will have extreme difficulties to fully electrify. Increasing the share of biofuels significantly beyond the quantities projected in a basic decarbonisation scenario context is not considered a viable strategy, as sustainability of production would be jeopardised. While passenger road transportation could be fully electrified and rail is considered to be fully electrified, long distance road transportation, aviation and shipping cannot be fully electrified. Modal shifts mainly to rail could be considered (and are considered within the model), however capacity constraints due to limitations from the network do not allow extreme shifting: extreme technical solutions such as electric airplanes are therefore required. If short distance aviation is powered by electricity, this would shift part of the demand to high speed rail, due to higher tickets of aviation. The latter are the result of the needs for on-board battery (which is a significant cost). On the other hand, high speed rail faces capacity constraints due to limitations from the network. Biofuels and other uses of bioenergy are already high in a decarbonisation scenario context and close to what today is considered a sustainable potential, therefore it is imperative that further electrification occurs in order to achieve nearly zero emissions.

The supply side sectors require the most limited changes: the refuelling industry will be limited to biofuels and everything else will be related to power generation.

From a power generation perspective such a strategy requires the least additional capacity and generation (approx. 28%), however it will require additional capacities for flexibility and storage as the power system alone will be responsible of supplying uninterrupted power supply and follow demand load curves.

Electricity demand and generation

To achieve zero emissions, it is certain that electricity generation must increase: the magnitude of electricity increase will depend on the strategy followed.

The basic scenarios for the decarbonisation policy²³ project an increase in electricity generation of approx. 65% compared to 2015 in 2050. However, the basic scenario has significant remaining emissions in the energy sector by 2050 and has not dealt with reaching zero emissions after 2050. In this context, a large share of electricity generation comes from variable renewable energy sources and significant balancing power resources need to deploy until 2050.

The basic decarbonisation scenario context is one where the majority of power generation (over 70%) comes from renewable energy sources, however also nuclear, gas and solids with CCS play a role; further biomass with CCS is included to obtain some negative emissions. Scenarios with a more dominant role of nuclear or CCS (either gas or solids) could be possible, but have significant drawbacks from a current perspective. Nuclear while theoretically able to deliver both no emissions and theoretically hydrogen, has issues related to public acceptance, costs and waste management; many Member States are exiting nuclear and have banned new power plants. Carbon capture and storage on the other hand, has public acceptance issues related principally to the storage of carbon and also has remaining emissions as the maximum capture efficiency is around 90%. If there were more widespread use of carbon capture and storage the

²³ The scenarios used in the Winter Package proposal of the European Commission in November 2016. The main scenario is referred in the present study as "basic decarbonisation scenario".

remaining emissions would require substantial negative emissions: options would imply burning clean gas from air capture or biomass with CCS in order to achieve negative emissions. While this option is theoretically possible, it is an extremely expensive strategy and has a very limited efficiency (approx. 10-15% for the entire cycle). Further using biomass with CCS is debatable as sustainable biomass resources are limited and can be more efficiently used for the production of biofuels.

Therefore, serious challenges stem from the significant increase in electricity demand involves in the strategies proposed throughout this study, especially for the hydrogen-carrier and the hydrogen-feedstock strategies. The projections show that the large increase in demand for electricity implies a significant further increase in the deployment of renewable energy sources for power generation (limiting however the use of biomass). The projection finds particularly useful to using electrolysis to produce hydrogen in periods of excess production of electricity, which can then be stored for different time frames for re-electrification either through fuels cells or modified gas turbines which can burn hydrogen directly.

But, the strong electricity demand cases implied by the strategies which produce hydrogen or clean fuels for the end-uses brings renewable production close to maximum possibilities, at least with known renewable technologies.

A doubling of electricity, considering the limitations on nuclear siting and CCS implies a huge increase in production from renewable energy: such an increase implies reaching limitations of renewable potential within Europe. Such an increase requires additional capacity which could be achieved by assuming the development of capacity in remote areas with the additional requirements for transmission lines (direct current-DC) for example far offshore in the North Sea or outside of Europe in the Sahara, or alternatively by assuming development of new materials for solar power or which allow for the construction of higher/larger wind turbines which would allow to increase generation from already exploited less remote sites.

Discussion of modelling results

Achieving a zero emissions scenario from the energy sector is challenging: the reduction of the remaining emissions beyond the -80% GHG reductions achieved in roadmaps developed for the European Commission includes a number of issues to which it is not possible to provide conclusive answers with today's knowledge status.

It is imperative that already today the discussions are started and progress is obtained to facilitate the future achievement of a zero emissions scenario, so that ultimately the limitations and uncertainties are resolved.

All strategies presented within this study are not realistic from today's perspective: Technological developments need to occur which are highly uncertain. However, one of the great advantages of such a system which is ultimately based on electricity is that it would require very limited or any imports in the long term and security of supply issues would not depend on external factors.

Hydrogen from power has several key benefits:

- Substitution of fossil based H₂ production for non-energy purposes
- Provision of flexibility and storage for power generation
- Provision of an energy carrier (either directly or indirectly) for difficult to decarbonize energy sectors

The projections of sectoral integration through hydrogen focusing on the possible different uses of hydrogen have included H₂ as a carrier, versus H₂ as an intermediate

form to produce synthetic fuels (as a feedstock), and hydrogen limited to electricity storage.

Below there is a summary of the main advantages and uncertainties of each strategy:

	Main uncertainties	Main advantages
H ₂ as a carrier	<ul style="list-style-type: none"> ▪ Need for a dedicated hydrogen distribution and transport infrastructure ▪ Fuel cells development has to succeed in reducing costs ▪ H₂ storage at a large-scale needs to develop 	<ul style="list-style-type: none"> ▪ H₂ is an energy carrier valid for the entire system ▪ No limitations for car ranges, easier applicability to more transport modes ▪ Significant but manageable increase in power generation ▪ Lower costs than for hydrogen as a feedstock ▪ Transition phase can use natural gas infrastructure that needs gradual adjustment and upgrading
H ₂ as feedstock	<ul style="list-style-type: none"> ▪ CO₂ capture from air is uncertain technologically and economically ▪ Extreme increase in demand for electricity ▪ High unit costs of the clean end-products, however competitive at high enough carbon prices ▪ Poor overall energy efficiency 	<ul style="list-style-type: none"> ▪ Continued use of existing distribution infrastructure for gas and liquid fuels ▪ Convenient energy applications, equipment and processes ▪ No major disturbance of transport system ▪ Full import independence
H ₂ for power storage	<ul style="list-style-type: none"> ▪ Electric aircrafts, ships and long distance trucks is uncertain ▪ Electrification of all industrial processes requires new technologies ▪ Electrification of all residential energy uses may decrease utility compared to the convenience of using gas ▪ Electricity becoming the single energy form for consumers implies concerns about the impact of lack of reliability in the power sector 	<ul style="list-style-type: none"> ▪ High efficiency of electricity in end-uses ▪ Feasible from power system perspective ▪ Power-to-H₂ used mainly for storage purposes can develop without major uncertainties and can achieve low costs ▪ Very affordable at the level of the power system

A balanced sectoral integration scenario: A realistic deep decarbonisation pathway for the long term to 2050

Description of the main scenarios analysed in the study

The previous section of the current chapter has presented a total of three stylised strategies that can provide incremental emission abatement on top of the emissions reductions achieved in a decarbonisation scenario, as the one used in the preparation of the proposals included in the Winter Package.

Such a **basic decarbonisation scenario** has been constructed as part of the current study. The scenario assumes that the EU climate and energy targets for 2030 as included in the Winter Package proposals of the EC are met. In order to achieve these, the scenario includes several sectoral measures:

- measures for energy efficiency in the buildings sector,
- regulatory emissions standards for LDVs (Light Duty Vehicle) aiming at low emissions mobility,
- promotion of best techniques in industry,
- facilitation of renewables in various sectors.

The scenario also includes ETS as a multi-sectoral market-based measure, but due its sectoral scope to the power and heat supply and several industrial sectors, additional measures are required. Therefore, energy efficiency enhancement and renewable energy development are considered the system-wide pillars of the transition towards a low-carbon European economy.

The main sectoral integration mechanism included in this scenario context is the enhanced role of electricity, for the decarbonisation of end-use sectors that are currently largely dependent on fossil fuels, e.g. the transportation sector. The penetration of Low Emissions Vehicles in the fleet of cars and vans, driven by the introduction of stricter than today regulatory emissions standards, and the penetration of electric heating systems in the building sectors (heat pumps), offer opportunities for significant GHG emissions reductions in end-use, however overall emission reductions can only be achieved with the power sector heads towards full decarbonisation. If the latter does not materialise, no net benefits in terms of system-wide GHG emissions will be achieved. The development of advanced biofuels is also a sectoral integration means needed to complement road electrification and reduce emissions from the transport sector. An intensified role of advanced biofuels in the transport system requires parallel and coordinated developments in certain sectors along the full biomass-to-biofuels conversion chain, most notably in the agriculture sectors and fuel conversion sector (bio-refining).

The quantification of such a scenario, using the PRIMES energy systems model has revealed that in the long-term (2050) important amounts of energy and industrial process CO₂ emissions persist. The majority of unabated emissions originate from the transport sector, the industry and the building sectors. Therefore, in order to achieve the deep decarbonisation in the EU energy system that would be compatible with the pursuit of a 1.5°C target, as indicated by the concluding text of the COP21 meeting in Paris in 2015, it is necessary to further augment the intensity of the sectoral measures and achieve a higher level of sectoral integration. Such integration can be achieved via the enhanced role of hydrogen in the energy system and its wide introduction as an energy carrier, as a means of energy storage and as feedstock element for the production of synthetic fuels. These three distinct roles of hydrogen have been analysed in the three strategies analysed presented in the previous section.

Each strategy has its own strengths and weaknesses that stem from the different characteristics of the technologies that are required to develop in each strategy, the uncertainty surrounding the pace of learning, the need to upgrade infrastructure networks for the transportation of new energy carriers, the growth in electricity generation needed under each strategy, etc. All three strategies have the merit to lead to an almost emission free and energy independent European Union. They are all affordable in terms of total energy system costs, provided that the new technologies exploit their learning potential and the infrastructures develop without market coordination failures. They can all lead to the EU energy system becoming almost carbon free by mid-century.

However, the analysis of the strategies is inconclusive whether either one of these strategies would be a realistic image of the evolution of the future EU energy system in the long term, as all strategies contain major uncertainties which cannot be solved at the moment. For instance, the electrification of aircrafts on a massive scale is questionable, as well as the widespread penetration of hydrogen-powered fuel cell stacks in the buildings sector for heating purposes (along with the development of the relevant transportation infrastructure,). As a result, all three cases contain considerable uncertainties surrounding their future performance regarding costs, efficiency and the timing of readiness. None of them should be treated as an optimal pathway for the European energy sector; a more balanced approach needs to be adopted, inheriting the strong points of each strategy.

The aforementioned considerations have led to the design of a new scenario which aims to optimise to the use of hydrogen and further enhance sectoral integration in a way that the advantages of hydrogen both as fuel and feedstock are amplified, in uses that are found to be economically viable. This scenario is called the **balanced scenario**.

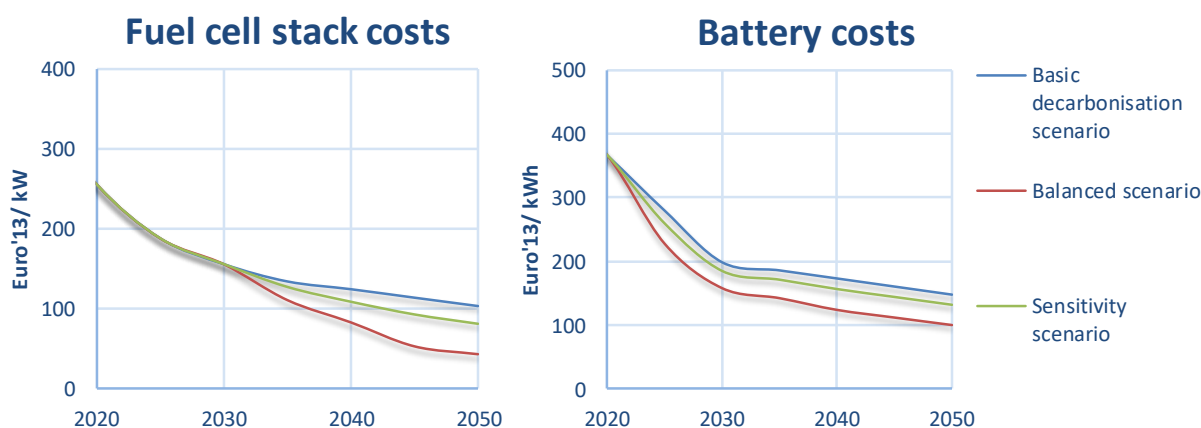


Figure 21: Development of fuel cell stack and battery costs in the three scenarios considered

The balanced scenario is built on top of the background context underlying the basic decarbonisation scenario, i.e. it should be seen as an add-on not as an alternative. In this perspective, the key pillars remain the same – strong energy savings in buildings and industrial sectors driven by energy efficiency policies; very high share of renewables in the energy system, especially for power generation; strong push of electrification of the light transport sector and stationary applications where applicable; introduction of advanced biofuels to decarbonise non-electrifiable transport segments. Beyond these elements, the balanced scenario assumes that the strengths of hydrogen as analysed in the presentation of the three strategies are further exploited: hydrogen is expected to penetrate energy market segments where it can provide a cost-effective solution to further GHG emission reductions.

The introduction of hydrogen is based on the assumption that hydrogen based technologies will develop significantly in the coming years: electrolyzers for the production of hydrogen, fuel cells particularly for the use in heavy road transportation and long distance transportation, as well as for industrial purposes in high temperature processes. Fuel cells for heavy road transportation are a key element of the balanced scenario as they allow to decarbonise a difficult sector to electrify which in the basic decarbonisation scenario is responsible for the majority of remaining emissions in 2050. In the basic and moderate scenarios, fuel cell costs are assumed to decrease, but to a lesser extent. The battery costs assumed for the balanced scenario are also lower than those of the basic decarbonisation, reflecting recent information on learning potential and the better focus of battery markets as assumed in the balanced scenario.

More precisely, the following uses of hydrogen have been found to be efficient for emission abatement and economically viable, in case hydrogen technologies achieve both economic and engineering maturity:

1. Mix hydrogen up to 15% in the gas distribution grids, together with amounts of bio-methane and clean methane (produced from hydrogen and CO₂ captured in the air); the share of the latter reaching between 15-20% in the long-term.
2. Use electrolysis-derived hydrogen to feed fuel-cell powertrains in large vehicles (trucks, buses, etc.) and long distance travelling cars (including taxis). Hydrogen refuelling can benefit from returns to scale as only a few numbers of large centralised fuelling hubs are required to feed the large vehicles.
3. Use hydrogen directly in high temperature furnaces in industry, including in iron- and steel-making, the chemical industry and other industrial sub-sectors.
4. Develop power-to-H₂ technologies in the power sector to provide electricity storage services at a large-scale, as needed to maximise the use of renewables, and produce hydrogen and clean methane used by consumers.

As already mentioned, the balanced scenario, despite the fact that it targets hydrogen to be used only in energy and industrial applications where it is more economically viable, assumes that technologies both on the demand (fuel cells, industrial processes involving hydrogen) and supply side (electrolyzers) become fully mature, with their efficiencies improving significantly compared to current levels and their cost reducing significantly. As the latter can be arguable, a sensitivity analysis has been conducted: the sensitivity scenario assumes a less optimistic development of hydrogen technology costs. The scenario includes the same developments of hydrogen uses as the balanced scenario but at a slightly lower extent due to the higher costs of hydrogen technologies.

Key scenario results and discussion

This section presents the key findings of the basic decarbonisation scenario and the balanced scenario, and a comparison between them. The sensitivity scenario is also compared where appropriate with the main scenarios. In order to provide more insightful results, all scenarios are also compared to the EU Reference Scenario 2016, the energy projections of which have also been prepared using the PRIMES model²⁴. In brief, the latter scenario assumes the implementation of policies adopted at EU level and in the Member States until December 2014 and in addition the ILUC amendment to the RES and FQD Directives, as well as the Market Stability Reserve Decision amending the ETS Directive. The EU Reference Scenario 2016 (in short Reference scenario) serves as a benchmark for policy scenarios.

²⁴ https://ec.europa.eu/energy/sites/ener/files/documents/20160713%20draft_publication_REF2016_v13.pdf

GHG emissions

The basic decarbonisation scenario achieves 84% CO₂ emission reduction in the energy and process sectors (including emissions from industrial processes) in 2050 compared to 1990 levels, a reduction compatible with the long-term objective of the EU to reduced total GHG by at least 80% (in 2050 compared to 1990). This reduction in the EU energy system is also consistent with the ambition to limit the global temperature increase to 2°C compared to pre-industrial levels. The world leaders participating in the COP21 meeting in Paris in December 2015 have also agreed to make best efforts to limit the global temperature increase to 1.5°C. In order to do so, further emissions reduction from the EU energy system will be required. The emissions savings achieved in the balanced scenario are in line with such a stricter trajectory, the balanced scenario achieves a 96% reduction of CO₂ emissions compared to the 1990, therefore almost eliminating energy and process related carbon emissions. It is noted that both trajectories achieve similar emissions savings in the mid-term (2030), equally respecting the EC targets included in the proposals of the Winter Package.

In absolute terms, around 700 Mt of energy and process related CO₂ emissions remain unabated by 2050 in the basic decarbonisation scenario. The remaining emissions in 2050 reduce to less than 200 Mt CO₂ in the balanced scenario. In the latter, the transport sector becomes essentially carbon-free by 2050 (compared to 375 Mt emitted in the basic decarbonisation scenario), as it fully utilises carbon-free energy carriers via:

- the maximization of the use of electricity in light transport segments;
- the use of hydrogen for long-distance travelling cars, hydrogen in long-distance travelling trucks, buses and coaches; and
- the use of advanced biofuels in aviation and shipping, which can use more biofuels than in the basic decarbonisation scenario as the biofuel consumption in road transport has been substituted with hydrogen.

Hydrogen is mainly used for longer distance trips, which otherwise were fulfilled with more expensive electric vehicles due to the high battery capacity needed, or continued using ICEs. This combines with fuelling hubs which can achieve attractive economies of scale, and avoids developing small scale H₂ refuelling that is expensive.

Industrial emissions, both from combustion and processes are reduced further in the balanced scenario to less than 30 Mt in 2050, in contrast with roughly 130 Mt in the basic decarbonisation scenario. Additional abatement in industrial emissions are due to the direct use of hydrogen in high temperature furnaces as reducing agent of iron or in other chemical reactions, and as a fuel in other industrial uses. Carbon emissions from the domestic sector are further reduced in the balanced scenario, but to a lower extent, since small scale fuel-cell stacks are not treated as a favourable option for heating in residential, public and commercial buildings. The additional savings in the balanced scenario are due to the higher shares of clean fuels blended in the gas distribution grid (mainly hydrogen and synthetic methane) leading to a lower average emission factor for distributed gas that is used in domestic boilers.

Energy supply is the only sector found to be slightly increasing its emissions in the balanced scenario compared to the basic decarbonisation scenario as power generation from RES increases significantly (see later section on power generation) and the balancing needs augment. Despite the very competitive position of variable RES towards the end of the projection period (several technologies become competitive without financial support already in the mid-term), gas-based generation²⁵ is still needed as a

²⁵ This is an issue for further investigation. Producing hydrogen for balancing and storage requires renewables which further require balancing and storage services. The system model finds a balance between the balancing and storage options in which there is a noticeable place of gas, which is produced from CCS CCGTs instead of producing hydrogen or clean methane and use them in CCGTs. The investigation will have to make sensitivity analysis about the relative

means of providing flexibility and balancing services to the power system. The vast majority of fossil-fuelled capacity is equipped with CCS technologies in 2050, however, the latter technologies still leave a certain share of post-combustion emissions (roughly 10%) unabated. The combination of those two elements (higher RES generation entailing higher needs for flexibility and balancing and a share of emission of CCS not being possible to be fully abated²⁶) leads to CO₂ emissions from the energy supply side increasing by roughly 7 Mt in the balanced scenario compared to the basic decarbonisation scenario.

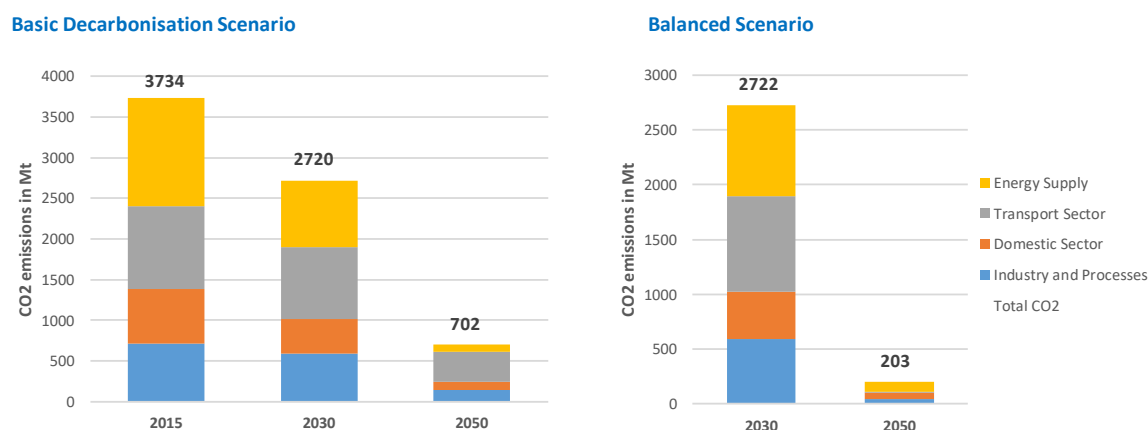


Figure 22. Evolution of CO₂ emissions from the energy sector and industrial processes in EU28

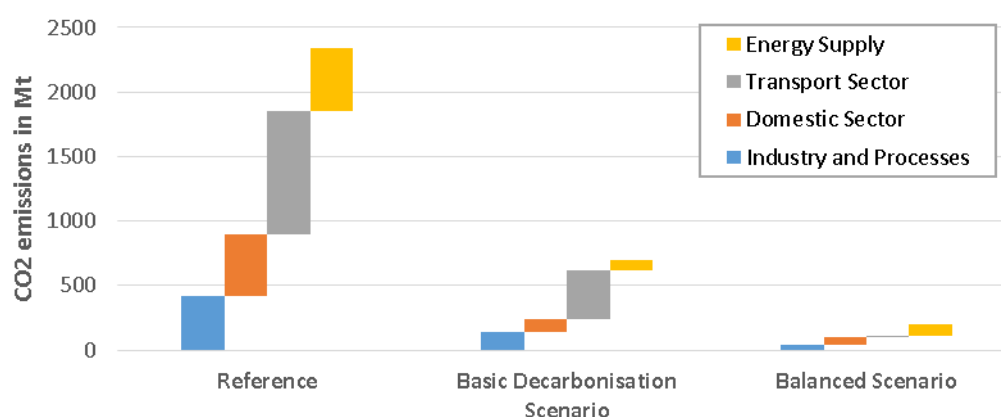


Figure 23. Remaining CO₂ emissions in EU28 in 2050.

Given the above, it is apparent that the relative shares of emissions from each sector vary significantly between the two decarbonisation scenarios in 2050. For example, the transport sectors emits more than 50% of the remaining energy and process related CO₂ emissions in the basic decarbonisation scenario, whereas this share in the balanced scenario drops to 5% (see Figure 24). The share of industrial emissions remains roughly the same, although the absolute CO₂ emissions decrease significantly. An increase in the share of supply side emissions from 12% to almost half of the CO₂ emissions in

economics of these options in a system with above 70% RES. There is poor literature on this issue, in particular regarding system modelling. This is logical as the topic is new in the literature.

²⁶ A further option would be to use biomass CCS to compensate for the non-abated (10%) emissions of gas-CCGT with CCS. The version of the model used in this study has restrictive assumptions about the development of biomass CCS before 2050.

2050 (45%) is noted, in emissions however only increase by 8% compare to the basic decarbonisation (7Mt CO₂).

Figure 24 shows the shares of the sectors in the emissions remaining in 2050 in the two decarbonisation scenarios. This figure should be seen in combination with Figure 22 which shows that the amount of remaining emissions in the balanced scenario are far lower those of the basic decarbonisation scenario.

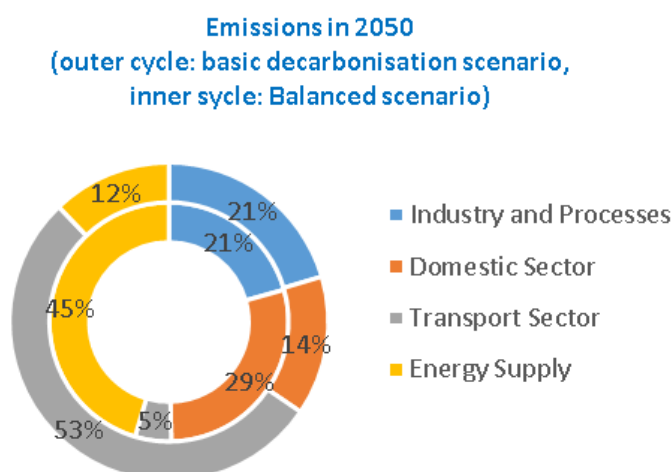


Figure 24. Relative shares of remaining emissions in EU28 in 2050

The role of hydrogen in the energy mix

It has been explained previously that the balanced scenario assumes the successful introduction and widespread adoption of hydrogen as a second level of sectoral integration in the European energy sector (the first level being the utilisation of carbon-free electricity), but only in sectors and end-uses where it has to exhibit strong and robust benefits compared to its carbon-free competitors (electricity, synthetic gas and liquids). Another important role of hydrogen is that it serves as one of the main feedstock elements—the other being carbon obtained from CO₂ – for the production of synthetic gas in these scenarios. The latter can be considered a carbon-free energy source in case the CO₂ used for its production has been obtained from non-fossil resources.

Further sectoral integration and deep decarbonisation achieved via an enhanced role of hydrogen in the energy sector, leads to important additional energy requirements for the supply of the latter. This is exhibited by contrasting the two main scenarios as shown in Figure 25. In both scenarios, the penetration of hydrogen in the energy sector initiates post-2030, with a much faster pace in the balanced scenario. Consequently, by the end of the projection period, around 55 Mt of hydrogen are consumed in the basic decarbonisation scenario, whereas this figure climbs to roughly 150 Mt in the balanced one. The remarkable increase originates from the use of hydrogen as an energy carrier for combustion in energy demand and supply sectors (or for direct injection in industrial processes), and to a small extent to its role as a feedstock for the production of synthetic methane; the share of the latter in overall distributed gas mix remains relatively close between the two scenarios.

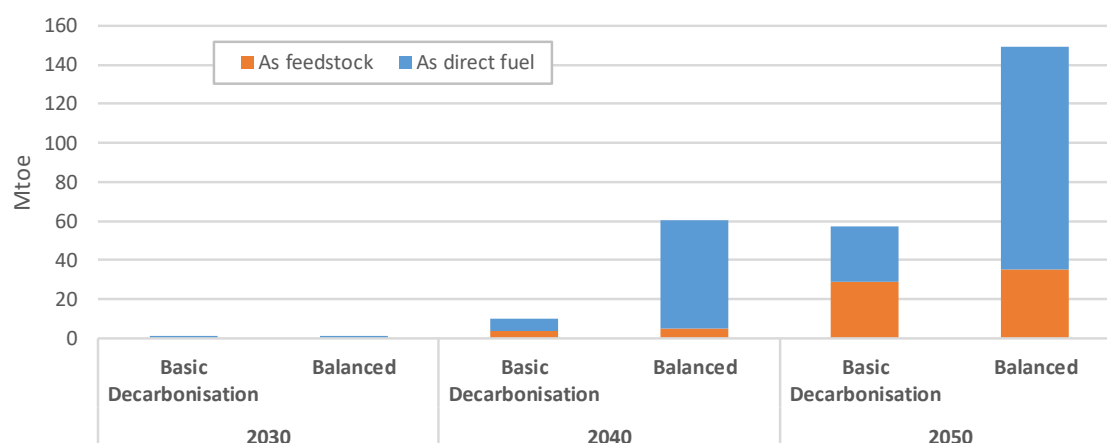


Figure 25. Hydrogen consumption for energy purposes in the EU28

Note: The figure includes quantities used for energy uses. Non-energy uses for hydrogen as feedstock are excluded.

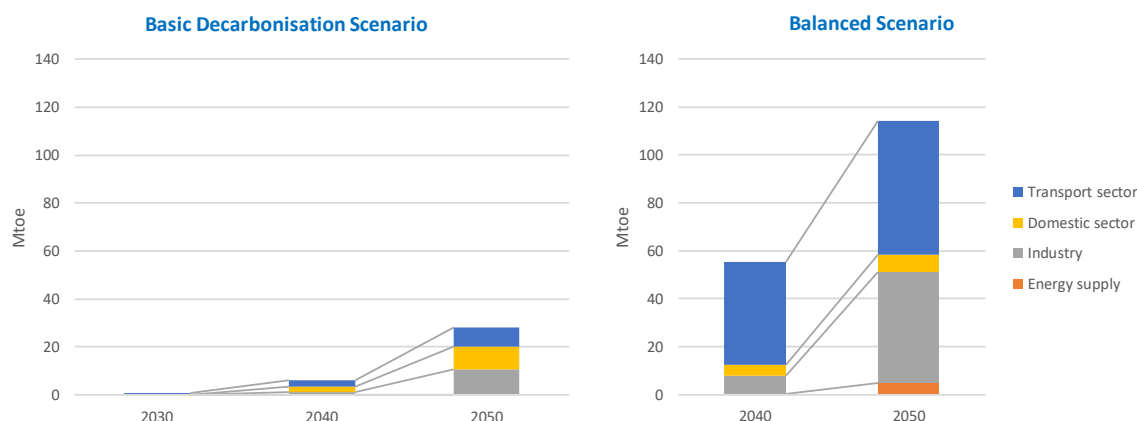


Figure 26. Consumption of hydrogen as a direct fuel per energy sector in EU28

The consumption of hydrogen used as an energy carrier for the two main scenarios is shown in Figure 26. The growth in the demand of hydrogen in the balanced case is mainly due to the transport and the industrial sectors and to a far lesser degree from energy supply (power generation).

In transportation, hydrogen is considered an attractive solution for the decarbonisation of long-distance road passenger and freight transportation (trucks and coaches), and several urban transport segments, where refuelling times need to be short and bulk refuelling in centralised stations within urban areas is possible, as in the case of buses and taxis. The rolling out of the infrastructure is assumed to be rapid, as it is assumed that there will be refuelling stations mainly with local electrolyzers, limiting the requirements for an extended infrastructure rollout with pipelines. Further the type of vehicles using hydrogen allow to limit the refuelling infrastructure to centralised refuelling and refuelling along key transportation routes (TEN-T network), limiting the hydrogen infrastructure requirements. For the transition period, decentralised hydrogen production is a valid option for private investment. The latter is considered an economically viable options as the modular nature of electrolyser units make them cost-effective also in small scale applications. This could also prove a significant benefit, till efficient logistics for the transportation of hydrogen in compressed/liquid forms are developed. The massive adoption of hydrogen in these transport modes brings its

consumption up to more than 55 Mtoe in 2050 in the balanced scenario, seven and a half times higher than in the case of the basic decarbonisation scenario.

Regarding its role in decarbonising the industrial sector, hydrogen can serve both as a fuel to power a combustion-based heater, which applies to plenty of industrial subsectors, or as an enabler of chemical reactions in certain industrial processes. Such is the case in the iron and steel sector, where hydrogen is used as an enabler of the chemical reaction reducing iron ore to iron. In the latter case, the use of high emitting fuels like blast-furnace gases used in traditional iron-making can be reduced. Certain, similar opportunities for carbon-free hydrogen produced through the use of electrolyzers are offered also in other industrial subsectors. All the above, complement the current role of hydrogen in non-energy related industrial applications where it has an established market. By 2050, hydrogen can contribute to almost 46 Mtoe of the energy needs of the industrial sector in the balanced scenario, compared to a limited contribution of roughly 10 Mtoe in the basic decarbonisation scenario.

Hydrogen also has an important role to serve for the power generation sector. Besides its use as a blend-in fuel in distributed gas, in gas-fuelled power plant, and even in modified turbines operating on high blends of hydrogen, it provides additional direct and indirect storage services to an integrated and interconnected power system allowing access to remotely located renewables and an effective sharing of balancing resources. The direct storage refers to the production of hydrogen via electrolysis in order to be converted back to electricity at a later time period; the indirect storage refers to the possibility to produce hydrogen for the demand sectors. The production of hydrogen can be optimised among power plant owners and hydrogen producers so that it can take place during off-peak hours of low electricity demand (and excess RES production). In this respect, the hydrogen-based storage of electricity has a considerable contribution to smooth electricity load-curves, being produced in times of excess generation and re-electrified in times renewables are in deficit. The maximisation of renewable capacity factors, enabled by hydrogen, helps lowering electricity costs.

Power Generation

The power generation requirements of the system increase significantly already in the basic decarbonisation scenario, as electricity is the main sectoral integration means leading to the reduction of emissions by demand sectors via fuel switching in the end-uses. Power generation has to increase much further to produce hydrogen (Figure 27). The increment is 33% in 2050 and can be higher if the balanced scenario developed further the clean gas or clean liquid productions. Despite the limited use of clean gas in the balanced scenario shown in the figure, the production of hydrogen is sufficient to drive the impressive rise of electricity production in 2050.

By the end of the projection period the gross generation of electricity increases by one quarter in the basic decarbonisation scenario compared to the Reference scenario, where decarbonisation is not pursued. When aiming at deep decarbonisation as is the case in the balanced scenario the increase of electricity generation is 70% relative to the Reference scenario. The high increase stems from the need to provide the electricity for the production of hydrogen via electrolyzers, as depicted by the share of the energy supply sector in total electricity consumption that increases substantially from 25% to almost 40% by the end of the projection period between the balanced and the basic decarbonisation scenario (Figure 28). Consequently, hydrogen serves as an additional level of sectoral integration, decarbonising non-economically electrifiable end-uses, given its zero-emission footprint when generated via electrolysis.

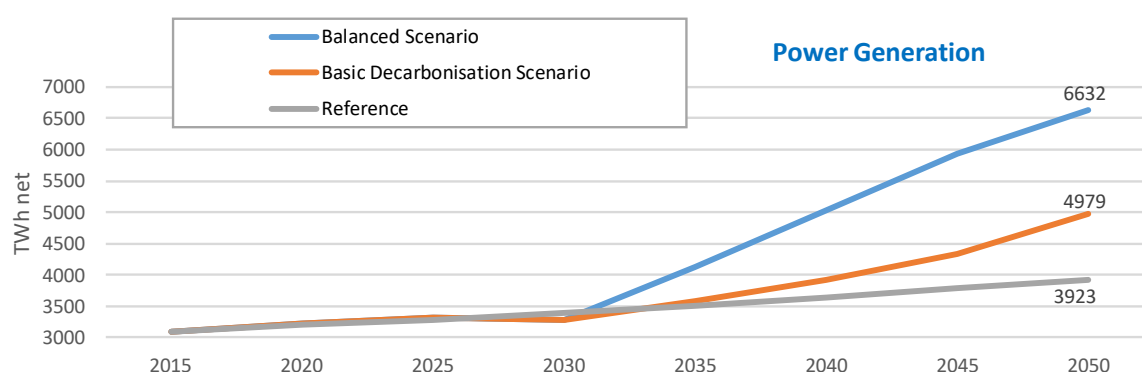


Figure 27. Power generation in EU28

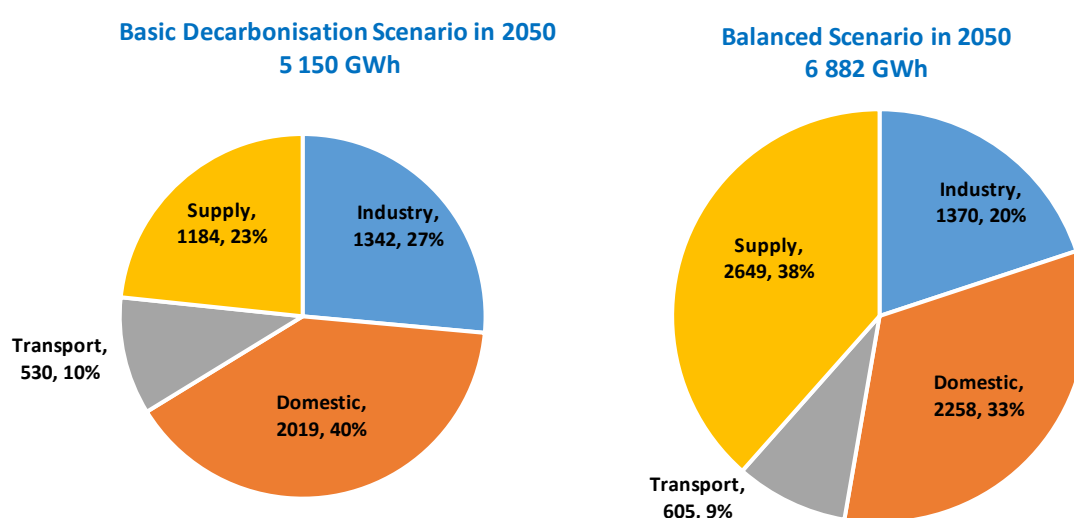


Figure 28. Electricity consumption by sector in EU28 in 2050

Power generation is almost carbon free by 2050 in all scenarios considered. The structure of power generation in both main scenarios is shown in Figure 29. By the end of the projection period, electricity production from RES dominates the power sector. Although, the RES share in generation does not change significantly between the two scenarios –they are slightly more than 70% in both cases – an increment of almost 1300 TWh in the balanced scenario is required compared to the basic decarbonisation scenario. All other major sources of electricity generation increase their contribution in terms of absolute electricity generation in the balanced scenario, but to a lesser extent. Nuclear power plants expand their production by 182 TWh (implying the expansion of the nuclear fleet by around 23 GW by 2050), a small rise compared to the rise of the RES (1912 GW in 2050 increment in the balanced scenario compared to the basic decarbonisation scenario), as the largest potential of the sites²⁷ available for the construction of new nuclear reactors have already been exploited in the basic decarbonisation scenario leaving small room for additional reactors.

Generation from solids and gas also increases but exclusively through CCS and for balancing purposes. Solids are used for power and heat generation exclusively in power plants equipped with CCS, slightly increasing their contribution in the power generation mix by mid-century from 59 TWh in the basic decarbonisation scenario, to 82 TWh in the balanced scenario. At the same time, gas-fired generation is increases by 164 TWh

²⁷ The PRIMES model limits the use of nuclear based on the availability of sites (locations) available in the countries allowing nuclear.

as a consequence of a number of underlying factors. Firstly, gaseous-fuelled power plants utilise mixtures of gases containing high shares of carbon-free energy carriers (synthetic methane, hydrogen and biomethane) leading to very low average emission factors for the overall mixtures. Secondly, any carbon-rich mixes of gases (containing low shares of clean fuels) are exclusively combusted in CCS equipped power plants, with low emission footprint. The use of CCS equipped power plants leads to a small part of unabated emissions which by that point in time are sufficient to lead to a net increase in emission from the energy supply side, as explained earlier (this is also true for CCS equipped power fuelled by solids). Lastly, due to the high-ramping rates, the low starting and shutdown costs and their low operating costs, gas plants serve as a cheap source for the provision of flexibility and balancing services to the power system; this becomes more and more important with increasing contribution of (variable) RES in the power mix.

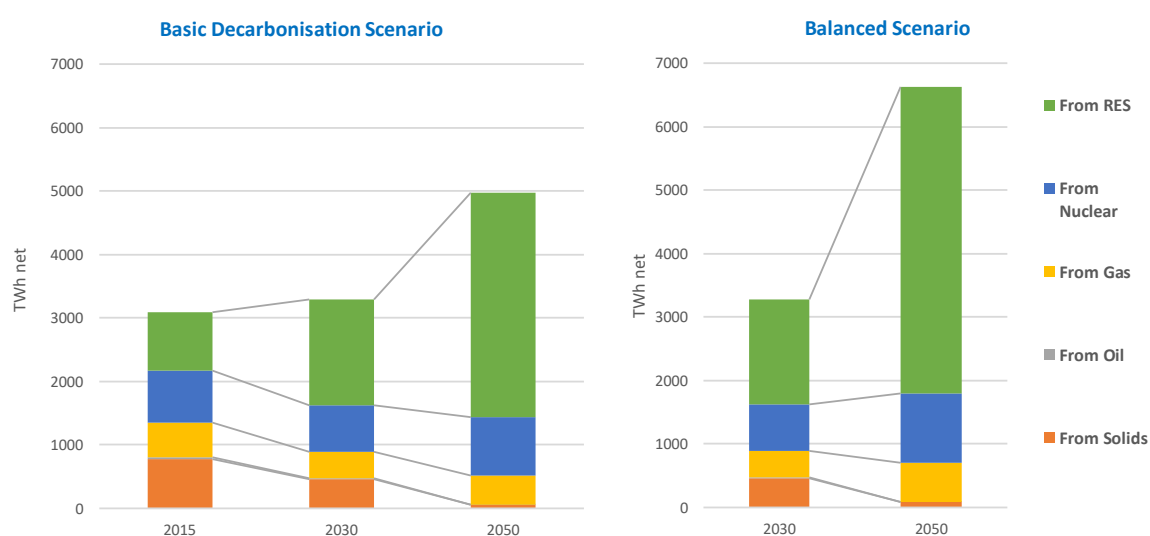


Figure 29. Structure of power generation in EU28

Transport

The balanced scenario assumes an increased role for hydrogen in those transport modes where limited alternatives to combustion engines are available or where strong business cases can emerge. In particular, hydrogen can achieve a large market share in long-distance road transportation modes (trucks and coaches) that are more difficult to electrify than light-duty vehicle transportation, where the strong emergence of EVs is anticipated. Another market opportunity for hydrogen is also presented in urban transportation e.g. for buses and taxis for which refuelling can take place in centralised stations (a few number per municipality) where it is possible to achieve economies of scale and short refuelling times that are highly beneficial. The roles of hydrogen and electricity should be seen hence as complementary, with each one aiming at the markets that better suit their technical characteristics. Figure 30 shows that the balanced scenario projects that the emissions in the transport sector can be almost fully abated (excluding bunkers), if the synergies of the sectoral integration are fully exploited.

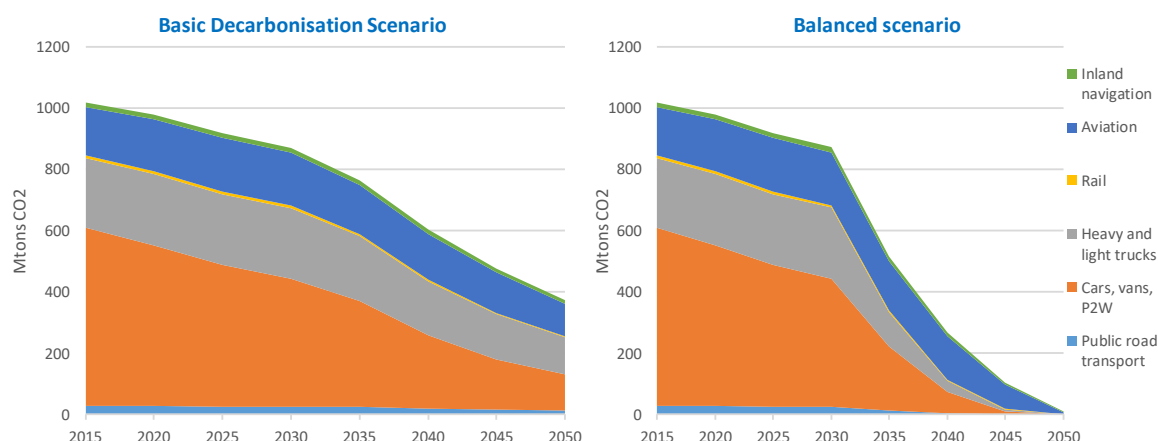


Figure 30. CO₂ emissions from the transport sector in EU28

In the basic decarbonisation scenario strong emissions abatements in long-distance road transportation can be realised only by the use of advanced biofuels. In the balanced scenario the use of hydrogen fuel cells avoids the use of advanced biofuels which can therefore be used in other transport segments. This is important because there are limitations to the amount of advanced biofuels that can be produced in the EU domestically due to e.g. limited land resources and suitability of land. The amounts of advanced biofuels that can be produced domestically in the EU are not enough to fully decarbonise all the remaining non-electrifiable transport modes –heavy duty road transportation, aviation and shipping–, in the basic decarbonisation scenario. Consequently, the use of hydrogen in long distance road transport reduces significantly the amounts of biofuels used in road transportation and therefore provides an opportunity for the full decarbonisation of aviation and shipping via the use of bio-resources (bio kerosene and other bio-liquids), without the need to depend on additional imported fuels or feedstock resources.

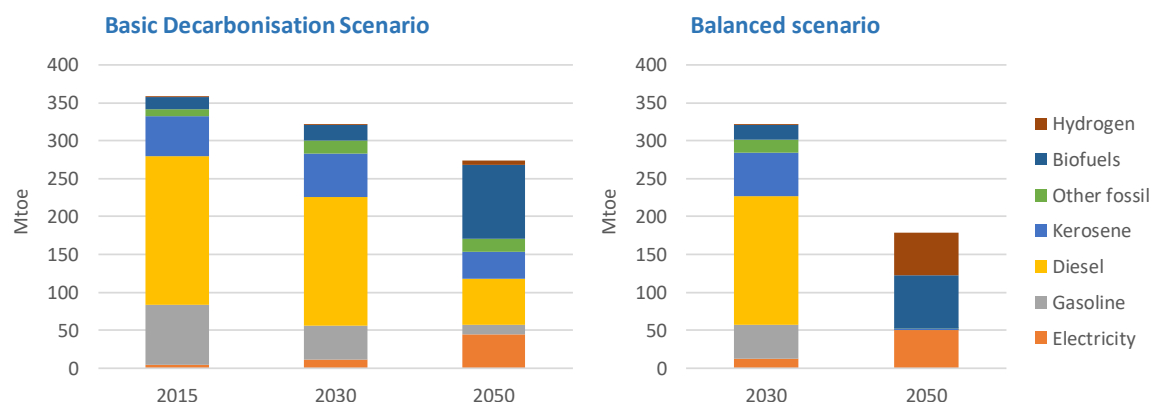


Figure 31. Energy consumption in the transport sector by fuel in EU28

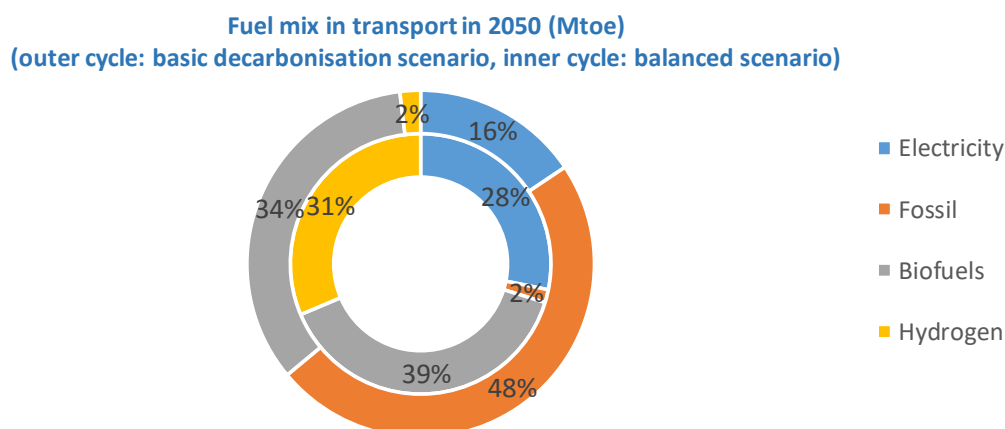


Figure 32. Fuel mix in transport in 2050

The balanced scenario for the transport sector shows an effective allocation of the contribution of three alternative energy sources that effectively contribute to the decarbonisation of transport in 2050. Electricity and hydrogen represent 28% and 31% of the total energy consumption in the transport in the balanced scenario (Figure 31 and Figure 32); biofuels represent an additional 39% of the total final energy demand.

Almost negligible quantities of fossil fuels remain in the fuel mix of the transport sector by mid-century. The picture is different in the basic decarbonisation scenario where large quantities of fossil fuels remain by 2050 (approx. half of the total final energy demand) which are responsible for the unabated CO₂ emissions in transport. Biofuels and electricity (to a lesser extent) hold the remaining shares in the fuel mix in the basic decarbonisation scenario in 2050. Hydrogen uptake is negligible in this scenario and its fuel share does not exceed 2%. However, the absolute consumption of biofuels in the two scenarios is very similar, despite the full substitution of jet fuels by biofuels in the balanced scenario. This is due to the savings of biofuels enabled by the use of hydrogen in road transport.

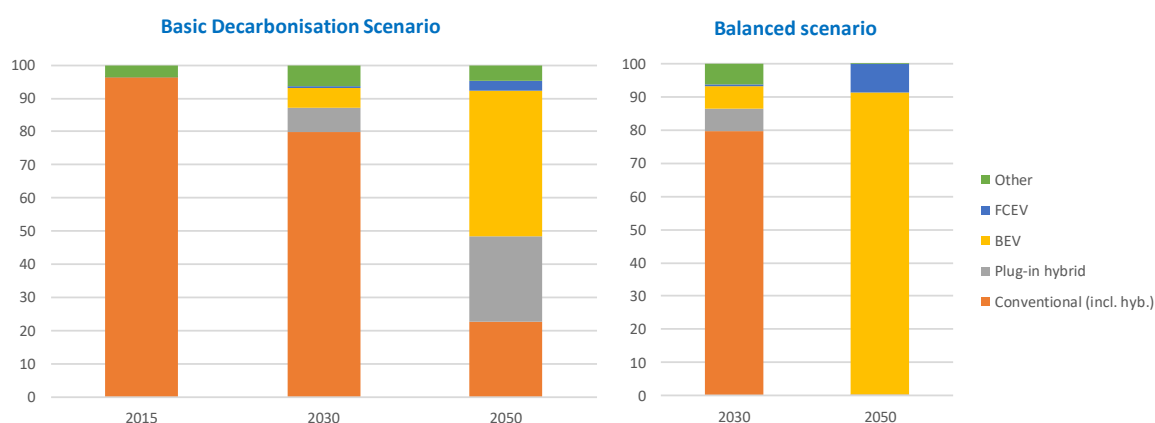


Figure 33. Shares of powertrains in the stock of cars in EU28

Electro-mobility dominates the car market of the EU28 in the balanced scenario, which enhances the developments in the basic decarbonisation scenario. This is due to slightly more optimistic assumptions regarding battery costs in the balanced scenario. The more optimistic figures are due to recent updates on technology potential costs compared to the figures used in the basic decarbonisation scenario back in end 2016. The battery-based powertrains concentrate in the market segments of cars travelling in cities and up to medium distances. The market focus can help batteries and the power trains achieving further economies of scale.

Battery electric vehicles hold the 90% of the total cars in the EU28, with the rest of the cars being fuel cell powered (Figure 33). The majority of the transport users are using battery electric vehicles for commuting and short-distant trips. Fuel cells occupy the market of transport users performing frequent long-distance driving or as vehicles with high daily utilisation (e.g. taxis). Similar developments are projected for buses and coaches and in general for heavy duty utility vehicles. In this way, the two vehicle powertrains represent two complementary options for the future private transportation. The stronger reduction in the battery costs of the BEVs from 2030 onwards in the balanced scenario relative to the basic decarbonisation scenario, is considered a major driver for their market. Hydrogen fuel cell cars also reach commercial level of maturity with a total cost of ownership similar to that of a conventional car, approaching 2050 (see Figure 35).

The balanced scenario shows that hydrogen can substantially contribute to the reduction in the CO₂ emissions from road-freight transport by 2050. The uptake of hydrogen increases significantly from 2035 onwards and dominates the segment of the heavy duty trucks (i.e. commercial vehicles above 3.5 tons) by 2050. First, hydrogen displaces consumption of diesel in the segment of long-haul trucks with high annual mileages on the European motorways. As approaching 2050, other truck types such as regional trucks or lighter ones operating in urban areas are also all switching to hydrogen (Figure 34). The uptake of hydrogen in the balanced scenario saves around 30 Mtoe of biofuels in 2050 that otherwise would be utilised by trucks, as shown in the basic decarbonisation scenario. These biofuel quantities that are being freed in the balanced scenario are used in other relatively inflexible to decarbonise transport sectors, such as aviation and ships.

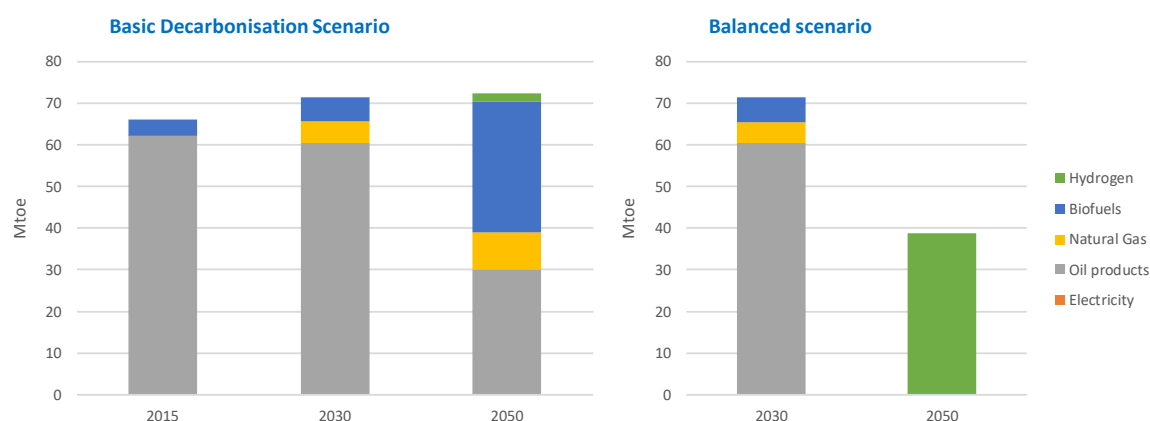


Figure 34. Fuel mix in trucks in EU28

The levelized costs of an average vehicle trip (as presented in Figure 35) include the annuity payment for the purchasing of the vehicle and the annual running costs (i.e. consumption of electricity, hydrogen or diesel).

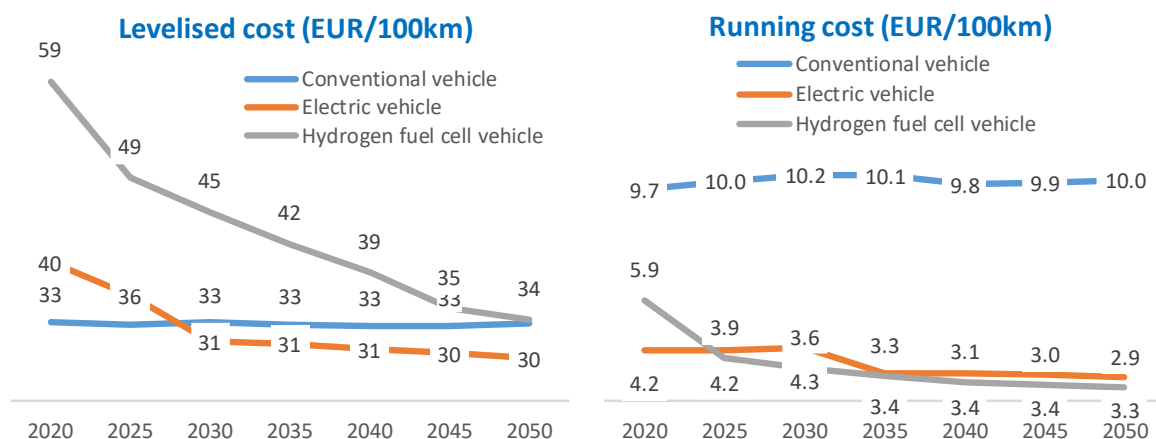


Figure 35. Levelised and running costs for an average medium-size car operating with conventional and advanced powertrains

Final consumption and gross inland consumption

The developments discussed in various subsectors, especially in industry and transportation, lead to a completely different energy mix in end-use sectors in the balanced scenario compared to the basic decarbonisation scenario by the end of the projection period (Figure 36). The demand sectors in the basic decarbonisation scenario are projected to consume 220 Mtoe of fossil based liquids in 2050; more than half (120 Mtoe) are still being used for energy applications (the remaining are used as feedstock for the production of chemicals, they are not combusted and hardly cause emissions). The respective figure for liquids used in energy applications in the balanced scenario is only 5 Mtoe, therefore oil products are almost eliminated from energy processes. Natural gas is the only carbon-emitting fuel that continues being used in significant quantities in 2050 (155 Mtoe and 130 Mtoe in the basic decarbonisation and the balanced scenario respectively), however, a considerable portion of it is carbon-neutral synthetic methane (17 and 23 Mtoe respectively). The remaining fossil methane is mainly used in industrial plants that are equipped with CCS/CCU technologies, therefore emitting small amounts of CO₂ and in the domestic sector, where some emissions remain unabated.

Direct use of renewables (mainly biomass) and waste in final energy shrinks by 35 Mtoe between the two scenarios as the increase of hydrogen displaces large volumes of advanced biofuels from the transport sector; fuel-cell powered engines are also more efficient than the respective conventional powertrains by a factor of two on average, contributing to this outcome, in final energy terms.

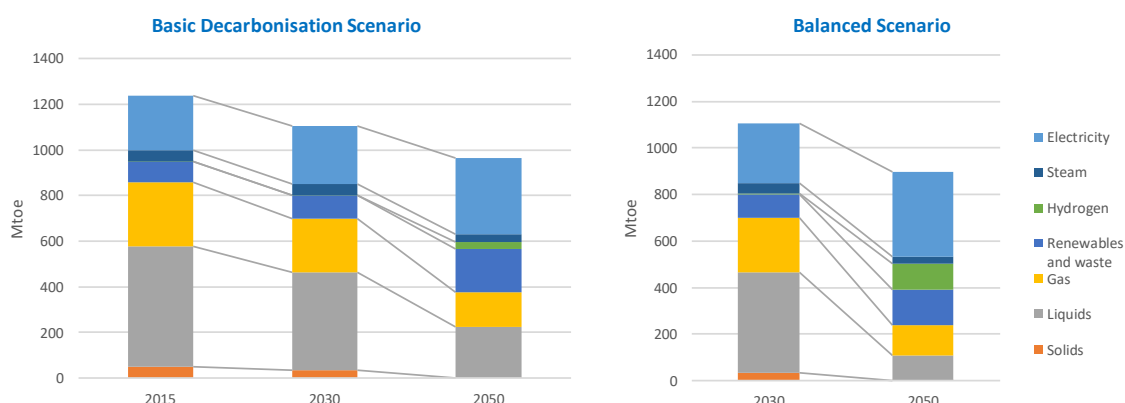


Figure 36. Total final consumption by fuel in EU28

Hydrogen and electricity are two energy carriers presenting the largest increase in their absolute contribution to the final energy mix in the balanced scenario compared to the basic one, increasing by 80 Mtoe and 30 Mtoe respectively. Hydrogen is widely adopted in certain industrial applications and transport segments, while electricity dominates the domestic demand and light road transportation. Hydrogen expands its role in this latter transport segment, however the increase is less prominent. Overall, total final consumption of all fuels decreases by 65 Mtoe between the two scenarios in 2050 (being lower in the balanced scenario), a result of the efficiency gains due the switch towards more efficient powertrains utilising clean fuels in transport.

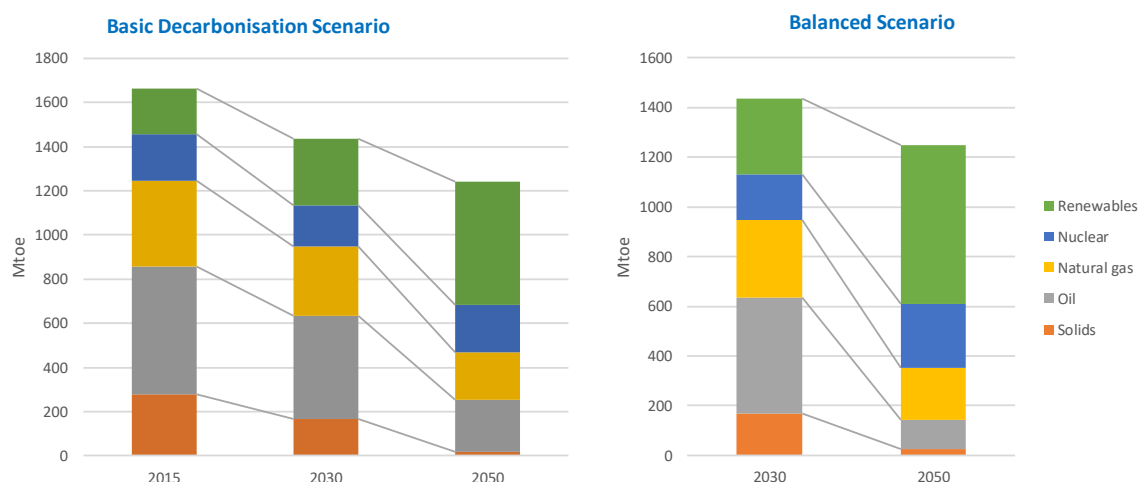


Figure 37. Gross Inland Consumption by fuel in EU28

Despite the decrease in total Final Energy Consumption due to efficiency gains in transportation, Gross Inland Consumption²⁸ of all primary energy sources used in EU28 increases slightly in 2050 in the balanced scenario compared to the basic decarbonisation scenario (Figure 37). This is an outcome of the high increase in electricity demand, including for hydrogen production, and consequently in the consumption of primary fuels need for its generation. As it has been mentioned in the power generation sector analysis, the majority of the incremental demand is covered by increased generation from RES and nuclear and to a lesser extent from gas and solids. The same is also evident in Gross Inland Consumption of those sources. As oil is used solely of non-energy purposes in the balances, its overall demand shrinks by more than 50%.

Gas, and more generally gaseous fuels, undergo a significant transition towards becoming low-carbon foot-print. At present, the vast majority of gaseous fuels are fossil methane (>93%), with the remaining gaseous fuels being coal-derived gases (5%) used in power generation and industry, and biogas (less than 2%). Only biogas is considered a carbon neutral energy carrier, therefore the gaseous fuel mix is quite carbon-intensive. By 2050, carbon-free energy carriers are blended in the distributed gas, or used directly in industry and power generation, leading to the gaseous fuel mix becoming significantly less carbon intensive (Figure 38). In the basic decarbonisation scenario, carbon-free gaseous energy carriers reach a share of roughly 30% in the overall gaseous fuel demand, and this share climbs to 45% in the case of the balanced scenario, mainly due the contribution of hydrogen. This trend has significant implications also for the supply of gaseous fuels. The European Union currently imports more than 65% of its gas. The introduction of gaseous fuels produced via chemical pathways (hydrogen, synthetic methane) brings the share of imports in the gaseous fuel mix down to 55% in the basic

²⁸ Gross Inland Consumptions is the sum of the fuel demand in end-uses sector and the energy supply sectors.

decarbonisation scenario and almost down to 42% in the balanced scenario by 2050. The latter is even more remarkable, should one consider that the overall demand for gaseous fuels remains stable between 2015 and 2050 in the balanced scenario, while it was shrinking by 20% in the main decarbonisation scenario. In this scenario, the amounts of gaseous fuels produced domestically in the EU in 2050, become comparable to the amounts of natural gas imported from outside EU (140 Mtoe and 170 Mtoe respectively).

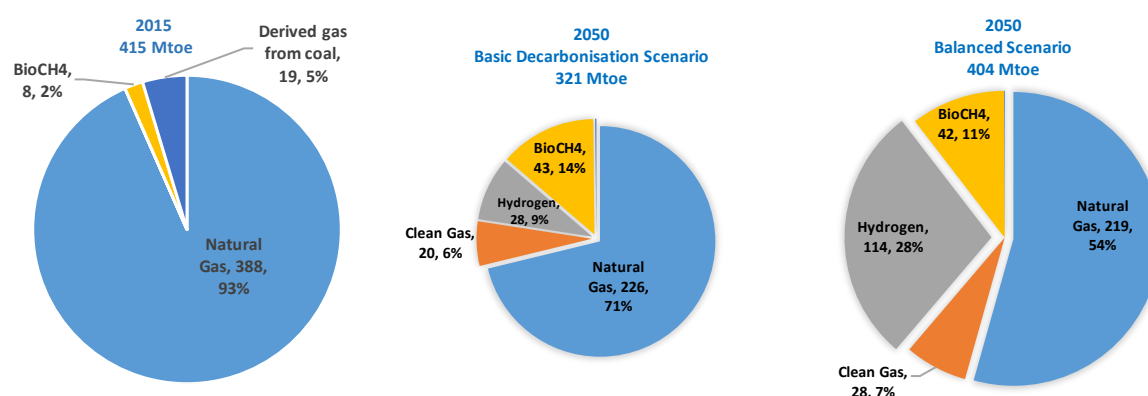


Figure 38. Gaseous fuel demand in EU28 in 2015 and 2050

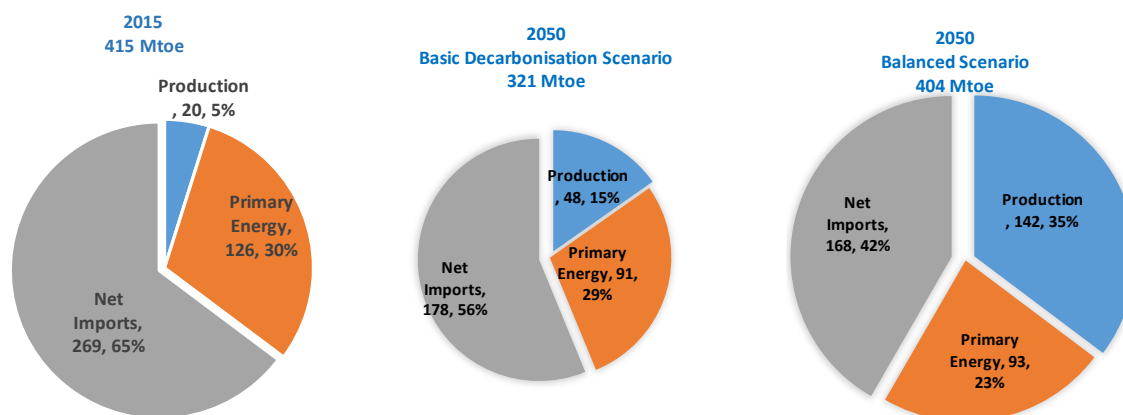


Figure 39. Gaseous fuel supply in EU28 in 2015 and 2050

Implications for imports and energy security

The substitution of fossil fuels has tremendous consequences on the EU trade balance, which however differs by scenario. The need for imports from outside the EU decreases over time in both the main decarbonisation scenario and the balanced one. But, the elimination of oil from the transport sector and almost all energy applications, except in non-energy uses, by 2050 in the balanced scenario leads to a dramatic fall of imports of liquids, standing at less than 170 Mtoe in 2050; they are used almost exclusively for non-energy uses in the chemical industry. For comparison, oil imports stood at roughly 550 Mtoe in 2015 and are projected to be 280 Mtoe by 2050 in the basic decarbonisation scenario (Figure 40). The oil import bill reduces by 93 billion € by 2050 in the balanced scenario compared to the basic decarbonisation scenario.

Imports of natural gas remain at the same level in 2050 across the two scenarios, despite the higher demand for gaseous fuels in the balanced scenario, as the incremental demand is covered by hydrogen and synthetic methane that are produced domestically within the EU. The imports of biomass are lower in the balanced scenario compared to the basic decarbonisation scenario, but in both cases the amounts of biomass are small compared to the domestic production. Both scenarios produce reasonable amounts of biomass domestically, and respect sustainability criteria and land use restrictions.

The overall reduction of net imports significantly improves the energy security position of the EU (Table 10) in the balanced scenario.

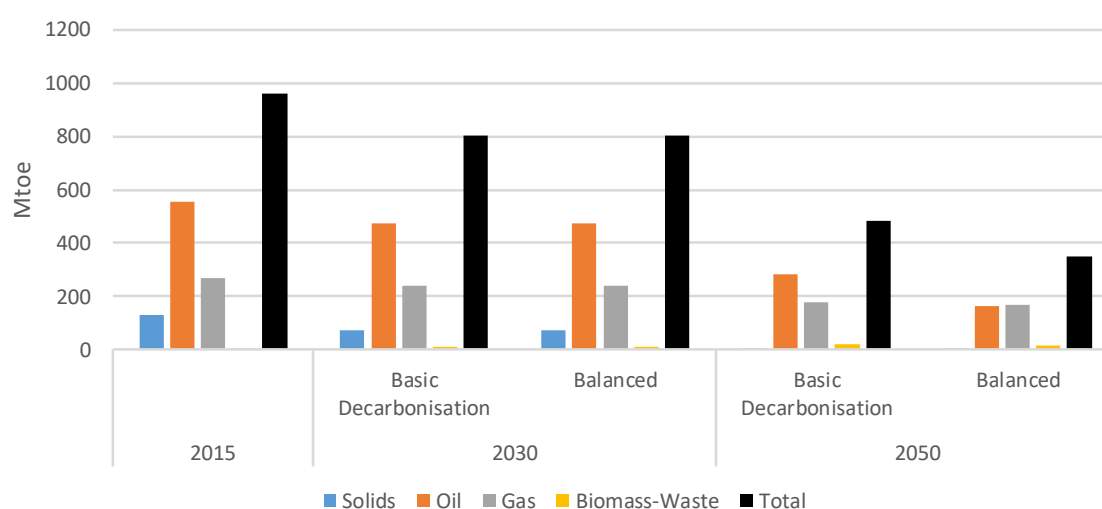


Figure 40. Net imports of fuels in the EU28

Import Dependency	2015	2020	2030	2040	2050
Balanced Scenario	56%	55%	54%	39%	27%
Basic Decarbonisation Scenario	56%	55%	54%	46%	37%

Table 10. EU dependency on imports

Economic considerations

The basic decarbonisation and the balanced scenario have been compared in terms of their relative cost performance. Despite the fact that the balanced scenario achieves higher emissions reductions, involves a significant increase in power generation and includes a higher share of more expensive fuels in the gas mix compared to the basic decarbonisation scenario, it is found to be less expensive than the latter regarding total energy system costs. In essence, the balanced scenario benefits from the availability of the hydrogen technology options and the reduced cost of fuel cells which by assumption were not available in the context of the basic decarbonisation scenario. In this sense, the two scenarios are not fully comparable regarding total cost performance. The merit of the sectoral integration enabled by hydrogen is that it enables stronger abatement and lower costs, just because this option has not been considered in the basic decarbonisation scenario.

Another economic benefit, of a lesser extent, comes from a more optimised allocation of emissions reduction effort across the sectors and the focused use of technologies.

This has been possible in the balanced scenario again thanks to the availability of the sectoral integration through hydrogen.

Both scenarios perform similarly in terms of both the average (and total) costs of the energy system and the average unit cost of emissions reduction up to 2030. In the long-term, the balanced scenario performs better in both regards. The average annual energy system costs in the period 2031-2050 is €2 444 billion in the basic decarbonisation scenario, whereas this drops to €2 360 billion in the balanced scenario. In other words, in the balanced scenario, the EU needs to spend on average €85 billion less than in the main decarbonisation scenario, every year for 20 years. The average CO₂ abatement cost is €88/t CO₂ (in the period 2031-2050), compared to €182/t CO₂ in the basic decarbonisation scenario. The lower cost is achieved thanks to the introduction of hydrogen as an intermediate fuel and its particular role in transport; the scenario benefits from the assumed techno-economic developments of the fuel cell technology, from €300/kW today to €44/kW in 2050 and the reduced costs of batteries.

The investment expenditures needed in power generation in order to produce the amounts of electricity required for the production of the incremental demand of synthetic fuels in the balanced scenario (compared to the basic decarbonisation scenario) require an increase in the cumulative investment expenditure of the power sector of roughly 50% in the period 2031-2050. In the same period, cumulative expenditure of €1.8 trillion are required for the additional investments in power plants, while the additional investments for the expansion of transmission and distribution grids is almost higher by two and a half times (€4.6 trillion). Despite the remarkable increase in power investment expenditure in the 20-year period prior to mid-century, the average electricity prices in the EU do not increase (Figure 42). On the contrary, marginal price decreases are observed as the power system benefits from increasing sales volumes.

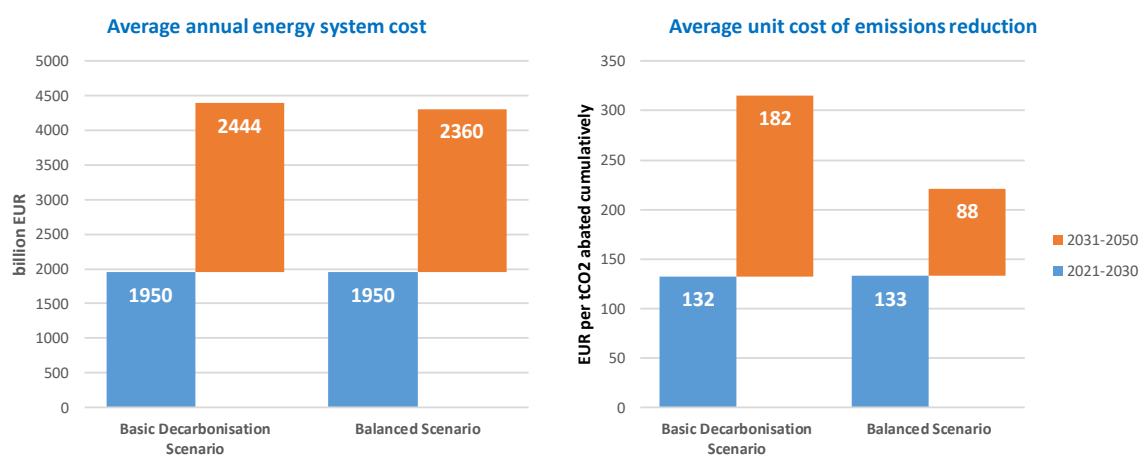


Figure 41. Average annual energy system cost (left) average unit cost of emission reduction (right) in EU28 for the two main scenarios

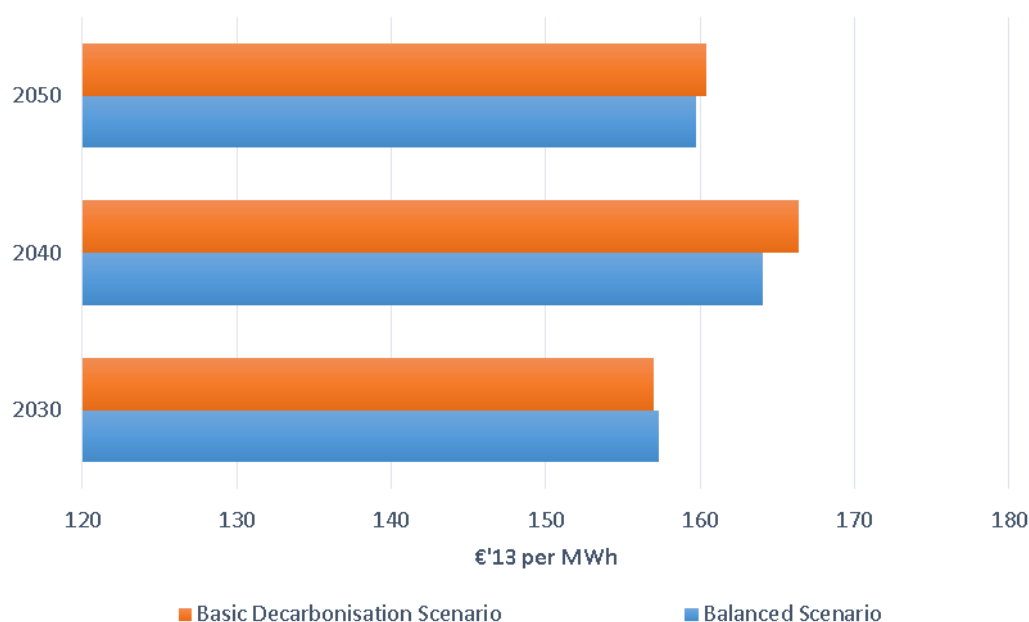


Figure 42. Average prices of electricity in EU28

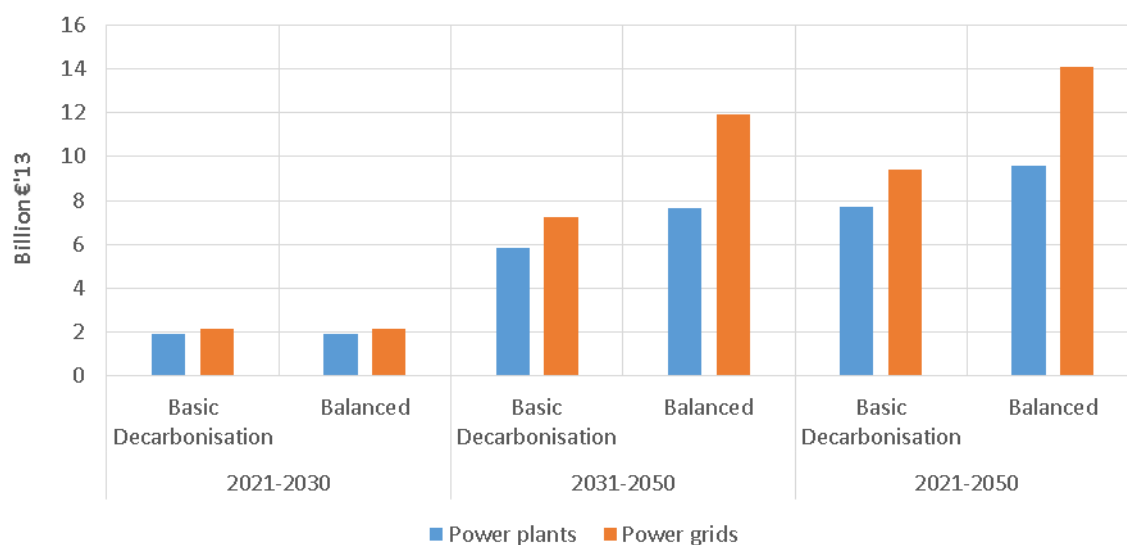


Figure 43. Investment expenditure in power generation

As it has pointed out in several other parts of the study, in order for any business model to be successful in the long term, the entire chain of users-producers-infrastructure should be available (almost) simultaneously. Such models are therefore vulnerable to market coordination failure: decentralised production in the initial expansion phase is less vulnerable, but for the development of the extent of hydrogen availability as envisaged in the strategies, successful market coordination is essential. Coordination is meant between infrastructure developers, technology and research providers, upstream hydrogen producers and end-use consumers. As the actors have different aspirations, long term anticipation and regulatory certainty are of utmost importance for market coordination. Consequently, without the successful coordination of the aforementioned market players, the optimality and cost-effectiveness of the balanced scenario is far from guaranteed.

Sensitivity analysis

The balanced scenario assumes that hydrogen technologies are used both on the demand side (fuel cells, industrial applications utilising hydrogen) and the supply side (electrolysers for the production of hydrogen), taking advantage of learning effects both due to R&D and accumulated experience (learning-by-research and learning-by-doing). The intensity and successfulness of the learning remains however uncertain. Therefore, the effectiveness of the strategic pathway presented in the balanced scenario is validated using a sensitivity analysis assuming less optimistic developments in the costs of hydrogen technologies. The sensitivity scenario includes the same developments of hydrogen uses as in the balanced scenario albeit at a lower degree due to the higher costs of hydrogen technologies.

Due to the higher costs associated with its supply and demand, the penetration of hydrogen in the sensitivity scenario is lower by the end of the projection period. In industry hydrogen covers 15% of the energy needs of the sector in 2050 in the balanced scenario. The higher prices of hydrogen, resulting from the higher production costs, lead to this share dropping to 12% in the sensitivity scenario. More prominent is the drop in the share of hydrogen used in transportation. In the balanced scenario, the reduction in the costs of fuel cells, make it possible for hydrogen to reach a 30% share in the transport energy mix, a share that drops close to 12% in case fuel-cell powered vehicles do not obtain full technological maturity (Figure 44). The total amount of hydrogen used in the EU either as a fuel or as feedstock for the production of synthetic methane in this scenario is 100 Mtoe, down from 150 Mtoe in the balanced one.

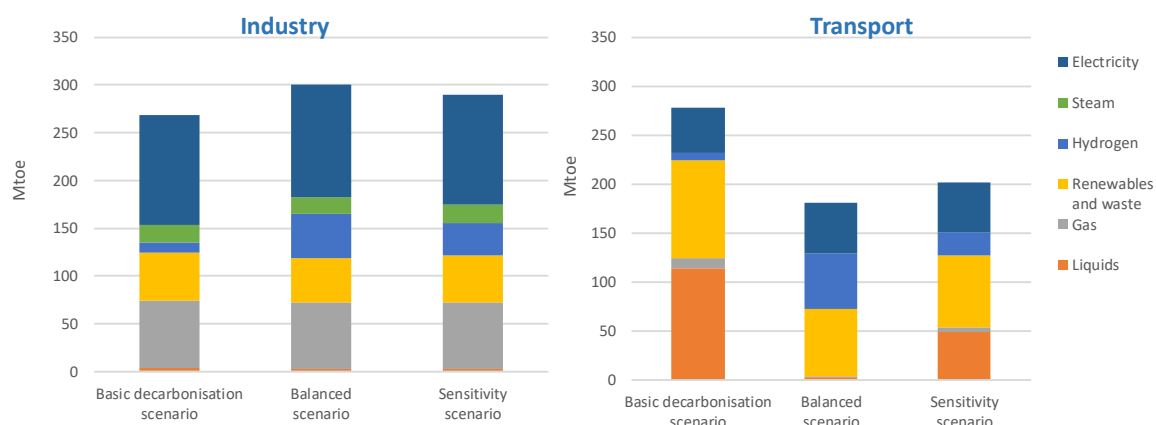


Figure 44. Final consumption by fuel in industry (left-hand side) and transport (right hand side) in EU28

These developments lead to significant amounts of CO₂ remaining unabated in the sensitivity scenario, with the impact being higher in the transport sector where 150 Mt of CO₂ more than in the case of the balanced scenario are emitted. The industrial sector emits 35 Mt CO₂ more and the remaining sectors around 30 Mt CO₂ due the higher costs of hydrogen that lead in turn to lower production of synthetic methane (Figure 45). The sensitivity scenario achieves a 90% decrease in energy and process related CO₂ emissions in 2050, compared to 1990 levels.

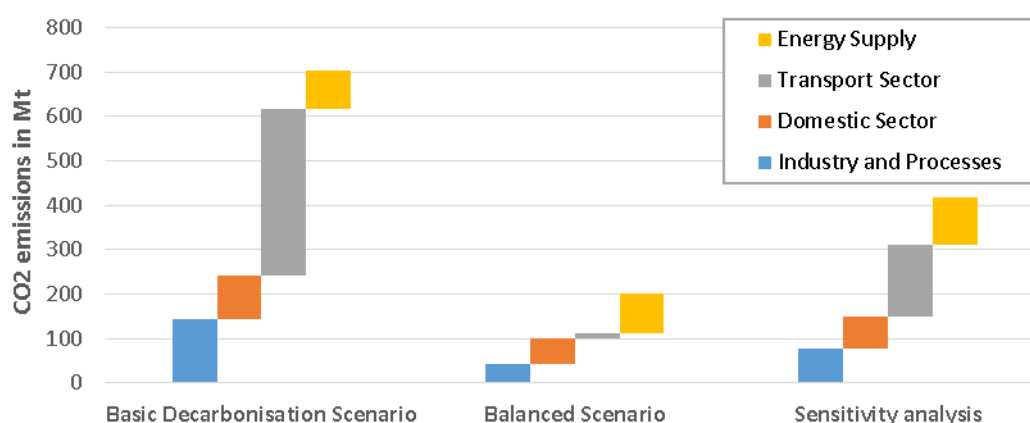


Figure 45. CO₂ emissions from the energy sector and industrial processes in EU28

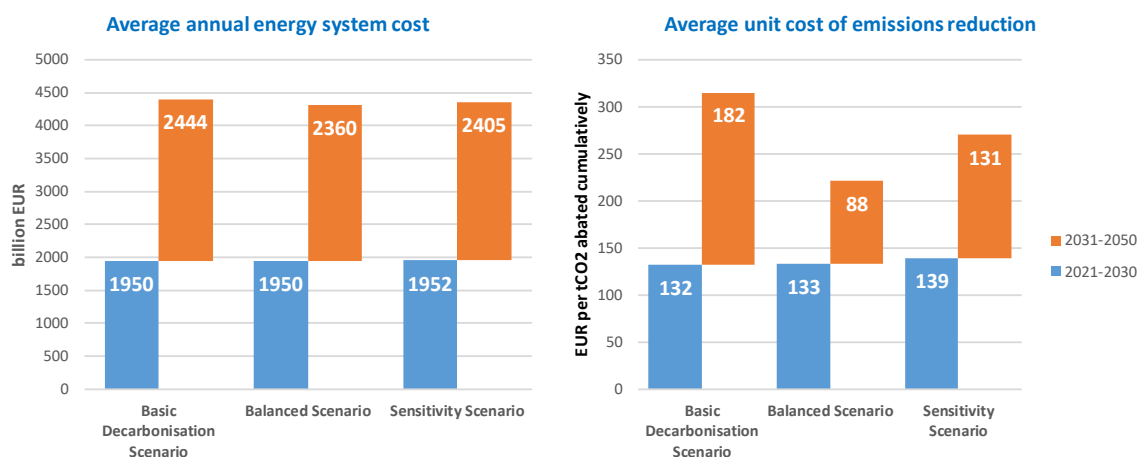


Figure 46. Average annual energy system cost (left) average unit cost of emission reduction (right) in EU28 for the two main scenarios and the sensitivity scenario

The higher costs of hydrogen technologies lead to the cost of the sensitivity scenario being higher than the balanced scenario but still lower than the basic decarbonisation scenario (Figure 46). On average, the sensitivity scenario requires additional average expenditures on the energy system of around 45 billion per year in the period 2031-2050, placing it in between the two main scenarios in terms of costs. As far as the average unit cost of emission abatement is concerned, these, although higher than in the balanced scenario, remain much lower than the basic decarbonisation scenario, indicating that emission reductions around 90% are possible, at affordable costs, even with less optimistic developments of hydrogen related technologies, however more optimistic than the basic decarbonisation scenario.

If hydrogen related technologies (both on the demand and supply side) reduce significantly in costs compared to today, they can become a key technology to help reduce emissions beyond the levels achieved in the basic decarbonisation scenario and at affordable costs. In order to achieve emission reductions beyond the 80% it is paramount that such technologies develop.

Conclusions and recommendations

Roadmaps for the European Union, such as those quantified by the PRIMES energy systems model for the European Commission, show that planned and existing measures take us a long way towards significantly decarbonising the European energy system, however emissions remain mainly in transport, the domestic sector and in industry. Abating these remaining emissions is complex and costly. Current policies and measures in place are sector specific (e.g. CO₂ standards for vehicles, or energy efficiency measures) or cover at maximum a selected number of sectors (ETS). In order to abate the remaining emissions, measures across sectors are required, therefore sectoral integration becomes necessary.

Strategies which allow for deep decarbonisation require sectoral integration policies and involve going beyond the role of electricity and considering using hydrogen as an energy carrier in various roles in the energy system. In this study, hydrogen is envisaged as a key element for the sectoral integration with different possible roles:

- (A) carbon-free hydrogen as an energy carrier and end use fuel,
- (B) hydrogen as a feedstock for the production of carbon-free gas and liquid hydrocarbons, and
- (C) hydrogen as a versatile power storage while electricity as a carrier is fully used in the energy consumption sectors.

In this study we have presented three strategies to elucidate the advantages and disadvantages of the use of hydrogen in these three roles. All strategies require ramping-up the production of hydrogen but differ in the way they foresee it being used. The strategies therefore require technologies producing carbon free hydrogen, and then the development of technologies which are strategy specific: strategy (A) requires fuel cells, strategy (B) power-to-liquid and power-to-gas technologies, and strategy (C) the development of electric end –use technologies for all sectors, including e.g. aviation. These technological developments are not mature today; the timing of their development and future costs are difficult to estimate.

The study has reviewed in a bottom-up manner a number of hydrogen-related and power-to-hydrogen technologies and assesses the market potential for carbon-free (green) hydrogen, as well as the use of electricity in mobility, industry and the domestic sector.

The study finds that there are options to use both hydrogen based and electricity based options for transport depending on the transport mode: thanks to their relative strengths there could be markets for both technologies, depending on the market segment, or transport mode.

For industry the use of carbon-free hydrogen, allows for the elimination of emissions in non-energy uses. For energy combustion for high temperature uses hydrogen can be directly injected in order to reduce emissions. Fuel cells, while not being applicable to high temperature uses, can provide an option to heat-pumps for low and medium enthalpy heat uses. Both heat-pumps and fuel cells can be used also for the domestic sectors: the former are reaching market maturity, whereas fuel cells are still very expensive. To be widely used as an end use fuel, hydrogen requires –aside from fuel cells– also the development of a transmission and distribution infrastructure. The adaptation of the natural gas infrastructure is possible, it is however a time consuming and expensive endeavour.

A common element for all strategies is the production of carbon free hydrogen production: as steam reforming is not carbon free, the production of hydrogen must take place through electrolysis. There are three major technologies available for the production of carbon-free hydrogen: alkaline electrolysis, Polymer Electrolyte Membrane

(PEM) electrolysis, and Solid Oxide Electrolyser Cell (SOEC). The former two are at a sufficient TRL and further cost reductions are possible if developed at a large scale. SOEC technologies are a promising technology, however they have currently at low TRL.

Storage of hydrogen is also a requirement for all strategies, to a lesser or larger extent depending on the strategy. The study has divided storage options into large and small. Large storage systems are required together with a large scale distribution system, in case hydrogen becomes a universal energy carrier, whereas smaller scale systems are appropriate for small and medium scale applications, in particular for facilities containing electrolysis plants and in large-scale hydrogen refuelling stations. Small scale systems are also technically and economically viable business cases for the transition period, while large scale development is underway.

A concrete business case for hydrogen –from today’s perspective- has been analysed within this study: hydrogen used to absorb excess electricity production from renewables and use of hydrogen within the same region. Regions have been studied where there are times of excess electricity production and possibility for hydrogen uses nearby. These areas can be forerunners and test sites for larger and long-term developments.

From a general perspective two business models are found to be viable for hydrogen production: decentralised hydrogen production close to end use or centralised hydrogen production. Decentralised options are adequate in the transition period. For the development of any business model, it is required that the development of demand and supply, as well as distribution, is performed almost simultaneously. For this reason market coordination failure is the highest risk for the development of the strategies; long term anticipation and regulatory certainty are the key factors to develop positive market coordination, for all strategies analysed.

Each one of the three strategies proposed has its merits and drawbacks. Strategy A – developing hydrogen as a universal energy carrier - has the advantage of one energy carrier which can be used in numerous applications. For transport it solves issues related to range limitations. Fuel cells can also be applied easier than electricity to a variety of modes including long-distance road transportation. However, the scenario relies on the uncertain development of fuel cells, at a large scale, for all transport segments and the development of a large-scale hydrogen infrastructure network of pipeline for the transportation of hydrogen to all end-uses, including households. Strategy B –hydrogen as a feedstock for power-to-gas and power-to-liquids- allows for the continued use of existing technologies in the demand side for transport modes that are difficult to decarbonise, specific industrial applications, as well as parts of the domestic sector. However, the scenario requires the development of carbon capture from air technologies in order for the fuel production to be carbon neutral, as well as a high increase in electricity generation since the fuel production chains are inefficient. Strategy C – hydrogen as storage- proposes to use hydrogen as a storage for excess electricity production and to electrify all end-uses in order to decarbonise them. While this strategy requires the least additional electricity production, it relies on the electrification of all end-use sectors, including transport modes such as aviation and industrial sectors where the chemical composition of outputs might need to be modified.

Each strategy is in itself a stylised case with extreme measures to highlight its advantages and disadvantages. However, a more likely outcome is a pathway that tries to take advantage of the positive aspects of each strategy without requiring extreme measures, therefore attempting to minimise the disadvantages of each strategy.

Such a **balanced** scenario could have the following characteristics:

- Hydrogen is mixed in natural gas uses up to the maximum technical feasibility (15%); further bio-methane and synthetic methane gas (produced using CO₂)

obtained via air capture) are also being blend in distributed gas streams, at share of 15-20% in the long term;

- introduction of hydrogen fuels cells in transport modes which cannot electrify such heavy duty vehicles and complimentary to vehicles travelling long annual mileages (e.g. taxis) or long-distances;
- use of direct injection of hydrogen in industry for high temperature furnaces, including in iron and steel, chemicals and other industrial sectors;
- power-to-H₂ technologies develop in order to a) provide storage services at large scale to the power sector, maximizing in this way the use of renewables and b) produce hydrogen and clean methane for utilization by end-use consumers.

In the balanced scenario, hydrogen fuel cells are exploiting their learning potential and thanks to development of optimized scale hydrogen fuelling hubs they can conquer those transport modes which are difficult to electrify, in particular heavy duty vehicles and generally any vehicle with high annual mileage. The development of refuelling hubs is economically appropriate for these market segments, and avoid deployment small scale refuelling of hydrogen that is expensive. The hubs can be placed in selected city areas and on major highways. The combination of hydrogen and electricity, limits the use of biofuels to sectors which cannot use either technologies therefore mainly aviation and navigation. These transport modes can therefore switch to much higher shares of biofuels, as quantities are freed from long distance road transportation.

For buildings energy efficiency and electrification will significantly reduce the consumption of natural gas and the remaining quantities will be covered by the mixture of hydrogen and bio-methane, as well as clean gas in the distribution of gas to reduce average emissions of the gaseous fuel.

For industry the strategy requires the use of hydrogen wherever possible to be directly injected to high temperature processes in order to minimize emissions. This is economically efficient also because hydrogen transport can focus on specific industrial areas.

In this way, the balanced scenario achieves 95% CO₂ emission reductions in 2050 relative to 1990, compared to 84% of the basic decarbonisation scenario. A sensitivity with less optimistic assumptions about the development of hydrogen related technologies, shows that emission reductions around 90% are nonetheless possible, at affordable costs.

Electricity generation increases by around 35% in 2050 compared to the basic decarbonisation scenario: thanks to the assumptions about full market integration and the interconnected system which allows to take advantage of remote locations for renewables, the average electricity price remain at the same levels as in the basic decarbonisation scenario, presenting even a marginal drop. The hydrogen based storage of electricity makes a considerable contribution to the smoothing of load and therefore allows to fully take advantage of overproduction and compensates for production deficit, maximizing the load factors of the renewables.

The average CO₂ abatement cost is €88/t CO₂ (cumulatively in the period 2031-2050, compared to €182/t CO₂ in the basic decarbonisation scenario. The lower cost is achieved thanks to the introduction of hydrogen as an intermediate fuel, its particular role in transport; the scenario benefits from the assumed techno-economic developments of the fuel cell technology, from €300/kW today to €44/kW in 2050, as well as the ones in battery cells. The average annual energy system costs in the period 2031-2050 is in the balanced scenario 3.4% lower than in the basic decarbonisation scenario. If hydrogen technologies would be more expensive in the long term, as in the sensitivity analysis, the energy system costs would still be lower in the balanced scenario compared to the basic decarbonisation scenario, but by 1.6% only. The average

CO₂ abatement cost would be €131/t CO₂ in the sensitivity scenario (cumulatively in the period 2031-2050).

The balanced scenario benefits from the availability of the hydrogen technology options and the reduced cost of fuel cells which by assumption were not available in the context of the basic decarbonisation scenario. In this sense, the two scenarios are not fully comparable regarding total cost performance. The merit of the sectoral integration enabled by hydrogen is that it enables stronger abatement and lower costs, just because this option has not been considered in the basic decarbonisation scenario.

The balanced scenario considerably reduces the import dependency to 27% due to two main reasons: gas use decreases significantly and almost half of the gas consumption is covered by hydrogen, clean gas and bio-methane; the remaining liquid fuel requirements in transport are covered mainly by advanced biofuels. The remaining imports of oil products are largely used for non-energy purposes (approx. 87%). The incremental energy required for the scenario is provided almost exclusively by renewables which are projected to be domestic.

The key technological achievements required for the balanced scenario are hydrogen electrolysis, fuel cells and industrial uses of hydrogen, as well as air capture. It minimizes the requirements for large scale additional infrastructure and excessive use of technologies which are at low TRL.

Although the balanced strategy is more conservative in terms of innovation requirements and finally emission reductions, all strategies presented within this study are not realistic from today's perspective: technological developments need to occur which are highly uncertain. It is imperative however that already today the discussions are started and progress is obtained to facilitate the future achievement of a zero emissions scenario, so that ultimately the limitations and uncertainties are resolved. If hydrogen related technologies (both on the demand and supply side) reduce significantly in costs compared to today, they can become a key technology to help reduce emissions beyond the levels achieved in the basic decarbonisation scenario and at affordable costs. In order to achieve emission reductions beyond the 80% it is paramount that such technologies develop in a timely manner.

Why does the discussion need to start today? The role out of the infrastructure and the emergence of such business models is expected to last over 10 years. Undertaking a back-casting exercise starting from the assumption that the aim is to achieve zero emissions by 2060, this would imply that already in 2050 very significant development needs to have taken place. Therefore, large scale roll-out of infrastructure and technologies need to have started by 2040 the latest. This again implies that already in 2030 a strategy needs to have been defined and the correct signals sent to the R&D and their investors to develop the required technologies. The financial requirements of each strategy are such that parallel developments are deemed not possible. The strategies require competing technologies that need such economies of scale that could not be warranted with parallel developments.

It is not necessary to decide on the strategy today, but the discussion and research needs to initiate. On the practical side, an acceleration of R&D is required in order to be able to understand and foresee with higher certainty which technologies will most likely be mature in the timeframe required, in order to decide on a strategical direction before 2030.

This study is a first scoping exercise which needs to be complemented by full energy systems analysis, studies to assess the financing needs, as well as the opportunities arising from the developments of such strategies for the European economy for exporting or for job creation. An assessment of energy policy instruments which will facilitate the development of strategies towards a more sustainable energy system,

along the lines described in this study are also required in order to enable the development and deployment of technologies and to underpin the market coordination requirements.

As a next step, not addressed in this study, we put emphasis on the assessment of suitable energy policy instruments which will enable emergence and wide spread of the technologies and facilitate market coordination. Further steps are also required to assess the sectoral integration strategies from a financing perspective and evaluate the impacts on industry, exports and employment in the EU. Further analysis of possible integration of clean hydrogen in the industrial processes and the produced materials also requires more in depth insights.

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APPENDIX: Technical and economic data

Technical and economic data which are currently in consultation. The last columns of the data indicatively calculate a levelized cost of output. This calculation is not as such in the model, which performs more de-tailed economic calculations of costs taking into account all aspects of the energy system. The levelized costs serve only illustration purposes.

For illustration only, the tables below also provide calculation of levelized unit costs for the output of se-lected value chains regarding distribution of end products.

The data in these tables are subject to change in the near future, as data collection and consultations continue.

Conversion technologies	Investment cost per unit of capacity (EUR/kW-output)			Fixed O&M costs (EUR/kW-output)			Capital and fixed cost per unit of output (EUR/MWh-output)			Variable, fuel and emissions cost per unit of output (EUR/MWh-output or per tCO ₂)			Total cost per unit of output (EUR/MWh-output or per tCO ₂)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Hydrogen from natural gas steam reforming centralised - Large Scale (per 1 kW or 1 MWh H ₂ HHV)	550	500	450	22	20	18	11.8	10.7	9.7	36	49	176	48	60	186
Hydrogen from natural gas steam reforming centralised - Large Scale with CCU (per 1 kW or 1 MWh H ₂ HHV)	900	850	800	36	34	32	19.3	18.3	17.2	88	115	249	107	133	267
Hydrogen from natural gas steam reforming de-centralised - Medium Scale (per 1 kW or 1 MWh H ₂ HHV)	1978	1598	1450	57	31	28	48.0	36.2	33.0	40	55	196	88	91	229
Hydrogen from low temperature water electrolysis PEM centralised - Large Scale (per 1 kW or 1 MWh H ₂ HHV)	2000	340	200	50	15	10	35.5	6.9	4.2	72	78	86	108	85	90
Hydrogen from low temperature water electrolysis PEM de-centralised at a refuelling station (per 1 kW or 1 MWh H ₂ HHV)	3000	750	350	70	34	18	52.6	15.2	7.3	78	82	87	131	97	95
Hydrogen from low temperature water electrolysis Alkaline centralised - Large Scale (per 1 kW or 1 MWh H ₂ HHV)	1100	300	180	28	14	9	19.5	6.1	3.8	73	83	87	92	89	90
Hydrogen from low temperature water electrolysis Alkaline de-centralised at a refuelling station (per 1 kW or 1 MWh H ₂ HHV)	1650	380	300	41	17	15	29.3	7.7	6.3	73	83	88	102	91	94
Hydrogen from low temperature water electrolysis SOEC centralised (per 1 kW or 1 MWh H ₂ HHV)	5000	2500	950	175	113	62	94.9	50.6	21.6	90	98	87	185	149	108
Hydrogen from low temperature water electrolysis SOEC de-centralised at a refuelling station (per 1 kW or 1 MWh H ₂ HHV)	7500	4375	1188	263	197	77	142.3	88.5	27.0	91	100	88	234	188	115

Conversion technologies	Investment cost per unit of capacity (EUR/kW-output)			Fixed O&M costs (EUR/kW-output)			Capital and fixed cost per unit of output (EUR/MWh-output)			Variable, fuel and emissions cost per unit of output (EUR/MWh-output or per tCO ₂)			Total cost per unit of output (EUR/MWh-output or per tCO ₂)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Methanation (per 1 kW or 1 MWh CH ₄ HHV)	1200	633	263	42	22	9	22.8	12.0	5.0	1	1	1	23	13	6
CH ₄ Liquefaction plant (per 1 kW or 1 MWh gas HHV)	450	450	450	18	18	18	7.7	7.7	7.7	9	13	40	17	20	47
Gas Liquefaction plant (per 1 kW or 1 MWh gas HHV)	200	200	200	20	20	20	4.8	4.8	4.8	2	3	4	7	8	9
Regasification Plant including LNG storage (per 1 kW or 1 MWh gas HHV)	175	175	175	5	5	5	2.7	2.7	2.7	0	0	2	3	3	5
Power to liquid via the methanol route (per 1 kW or 1 MWh CH ₄ HHV)	1000	620	364	50	31	18	20.9	12.9	7.6	7	10	34	28	23	41
Power to liquid via the Fischer Tropsch route (per 1 kW or 1 MWh CH ₄ HHV)	1556	1143	673	54	40	24	29.5	21.7	12.8	2	2	6	31	24	19
Power to liquid via High temperature co-electrolysis and Fischer Tropsch (per 1 kW or 1 MWh CH ₄ HHV)	2332	1511	965	163	106	68	54.5	35.3	22.5	111	118	165	165	153	188
Capture CO ₂ from air (Absorption technology) (per 1 tCO ₂)	770	648	335	27	23	12	116.9	98.4	50.8	0.18	0.15	0.17	117	99	51
Capture CO ₂ from air (Adsorption technology) (per 1 tCO ₂)	1260	894	270	44	31	9	191.3	135.8	41.0	0.06	0.08	0.22	191	136	41
CO ₂ Liquefaction plant (per 1 ton CO ₂)	174	174	174	3	3	3	3.2	3.2	3.2	0.01	0.01	0.02	3	3	3

Refuelling technologies	Investment cost per unit of capacity (EUR/kW-output)			Fixed O&M costs (EUR/kW-output)			Capital and fixed cost per unit of output (EUR/MWh-output)			Variable, fuel and emissions cost per unit of output (EUR/MWh-output or per tCO ₂)			Total cost per unit of output (EUR/MWh-output or per tCO ₂)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
H2 compression station (per 1 kW or 1 MWh H2 HHV)	114	102	91	0.4	0.4	0.4	2.3	2.1	1.8	3.6	4.6	5.1	5.9	6.6	7.0
Hydrogen Liquefaction plant (per 1 kW or 1 MWh H2 HHV)	761	635	457	23.0	23.0	23.0	12.1	10.6	8.4	1.1	1.4	1.5	13.2	11.9	9.9
H2 liquid to gas refuelling station (per 1 kW or 1 MWh H2 HHV)	855	759	568	1.6	1.4	1.1	16.9	15.0	11.2	3.7	4.6	5.2	20.6	19.6	16.4
H2 refuelling station Small (per 1 kW or 1 MWh H2 HHV)	1009	867	822	4.1	4.1	4.1	20.3	17.6	16.7	3.6	4.6	5.1	24.0	22.2	21.8
H2 refuelling station Medium (per 1 kW or 1 MWh H2 HHV)	542	412	379	1.7	1.7	1.7	10.8	8.3	7.6	3.6	4.6	5.1	14.5	12.9	12.8
H2 refuelling station Large (per 1 kW or 1 MWh H2 HHV)	325	247	151	0.7	0.7	0.7	6.4	4.9	3.1	3.6	4.6	5.1	10.1	9.5	8.2
ELC recharging points - Semi Fast recharging (per 1 kW or 1 MWh ELC)	240	240	240	9.6	9.6	9.6	5.8	5.8	5.8	0.0	0.0	0.0	5.8	5.8	5.8
ELC recharging points - Fast recharging (per 1 kW or 1 MWh ELC)	900	900	900	36.0	36.0	36.0	21.7	21.7	21.7	0.0	0.0	0.0	21.7	21.7	21.7
CNG compression station (per 1 kW or 1 MWh gas HHV)	89	89	89	5.7	5.7	5.7	2.7	2.7	2.7	1.2	1.5	2.0	3.9	4.2	4.7
CNG refuelling station (per 1 kW or 1 MWh gas HHV)	197	197	197	4.3	4.3	4.3	6.8	6.8	6.8	0.0	0.0	0.0	6.8	6.8	6.8
LNG refuelling station (per 1 kW or 1 MWh gas HHV)	120	120	120	3.9	3.9	3.9	4.5	4.5	4.5	0.0	0.0	0.1	4.5	4.5	4.6

Distribution technologies	Investment cost per unit of capacity (EUR/kW-output)			Fixed O&M cost per unit of capacity (EUR/kW-output)			Variable Cost EUR/MWh			Levelized cost per unit of product transported (EUR/MWh-output)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
NGS Transmission Network (per MWh) (per MWh)	126	126	126	5	5	5	0.7	0.7	0.7	2.7	2.7	2.7
NGS Distribution Network (per MWh)	552	552	552	22	22	22	3.2	3.2	3.2	19.2	19.2	19.2
H2 pipeline 60bar (per MWh H2 HHV)	178	173	166	7	7	7	1.0	1.0	1.0	3.8	3.7	3.6
H2 pipeline 10 bar (per MWh H2 HHV)	723	723	723	29	29	29	4.1	4.1	4.1	25.2	25.2	25.2
CO ₂ Transmission network (per tCO ₂)	Investment cost per unit of capacity (EUR/ton CO ₂ per year)			Fixed O&M cost per unit of capacity (EUR/ton CO ₂ per year)			Variable Cost EUR/kWh			Levelized cost per unit of product transported (EUR/ton CO ₂)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
CO ₂ Transmission network (per tCO ₂)	23	23	23	1.3	1.3	1.3	1.0	1.0	1.0	4.3811	4.3811	4.3811
	Investment cost per unit of capacity (EUR/kW-output)			Fixed O&M cost per unit of capacity (EUR/kW-output)			Variable Cost EUR/kWh			Levelized cost per unit of product transported (EUR/ton CO ₂)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Road transport of liquid H2	74	68	55	7	7	7	0.3	0.3	0.3	3.0	2.8	2.5
Road transport of gaseous H2	344	324	284	58	58	58	3.6	3.6	3.6	19.0	18.5	17.5

Storage technologies	Investment cost per unit of energy stored per year (EUR/MWh)			Fixed O&M costs (EUR/kW)			Variable, fuel and emissions cost per unit of stored energy (EUR/MWh)			Total cost per unit of stored energy (EUR/MWh)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Compressed Air Energy Storage (per 1 kW or 1 MWh electricity)	125000	112500	110931	38.5	34.7	34.2	0.0	0.0	0.0	225	203	200
Flywheel (per 1 kW or 1 MWh electricity)	1750000	1575000	1553029	52.5	47.3	46.6	0.0	0.0	0.0	1127	1015	1000
Large-scale batteries (per 1 kW or 1 MWh electricity)	600000	253000	225484	40.5	15.0	13.1	0.0	0.0	0.0	311	122	108
Small-scale batteries (per 1 kW or 1 MWh electricity)	270000	114000	101619	16.9	6.3	5.5	0.0	0.0	0.0	74	31	27
Pumping (per 1 kW or 1 MWh electricity)	100000	90000	88745	22.5	20.3	20.0	0.0	0.0	0.0	155	140	138
Underground Hydrogen Storage (per 1 kW or 1 MWh H ₂)	7200	7200	7200	0.0	0.0	0.0	0.6	0.7	0.8	4.7	4.9	5.0
Pressurised tanks - Hydrogen storage (per 1 kW or 1 MWh H ₂)	6000	4800	4659	0.0	0.0	0.0	0.6	0.7	0.8	3.0	2.7	2.7
Liquid Hydrogen Storage - Cryogenic Storage (per 1 kW or 1 MWh H ₂)	8455	6800	4000	0.0	0.0	0.0	0.7	0.9	1.0	4.1	3.6	2.6
Metal Hydrides - Hydrogen Storage (per 1 kW or 1 MWh H ₂)	12700	11430	11271	0.0	0.0	0.0	0.5	0.7	0.8	5.7	5.3	5.3
Thermal Storage Technology (per 1 kW or 1 MWh Heat)	100000	90000	88745	100.0	97.2	95.8	0.0	0.0	0.0	78.6	70.7	69.7
LNG Storage Gas (per 1 kW or 1 MWh Gas)	135	135	135	0.0	0.0	0.0	0.6	0.7	0.8	1.9	2.1	2.1
Underground NGS Storage (per 1 kW or 1 MWh Gas)	33	33	33	0.0	0.0	0.0	0.6	0.7	0.8	4.4	4.5	4.6
	Investment cost per ton CO ₂ stored per year (EUR/tCO ₂)			Investment cost per ton CO ₂ (EUR/tCO ₂)			EUR/tCO ₂ liquefaction cost			EUR/tCO ₂		
Liquid CO ₂ storage tank	1000	1000	1000	15	15	15	3.18	3.18	3.18	4.14	4.43	4.02

Value Chains Levelized costs EUR/MWh of CH ₄	Hydrogen feedstock			Methanation			CO ₂ captured			CO ₂ emission			Total		
	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate
Fossil natural gas										1.4	6.2	103.2	23.2	33.1	132.0
Synthetic Gas (via Steam Reforming Natural Gas)	60.8	76.6	237.2	23.3	12.7	5.7	11.9	14.6	16.2	1.9	8.0	132.1	98.0	111.9	391.2
Synthetic Gas (via PEM Electrolysis)	137.9	108.3	115.2	23.3	12.7	5.7	23.4	19.7	10.2	0.0	0.0	0.0	184.6	140.7	131.2
Synthetic Gas (via Alkaline Electrolysis)	117.9	113.8	115.7	23.3	12.7	5.7	23.4	19.7	10.2	0.0	0.0	0.0	164.6	146.2	131.6
Synthetic Gas (via SOEC Electrolysis)	236.1	190.0	138.5	23.3	12.7	5.7	23.4	19.7	10.2	0.0	0.0	0.0	282.8	222.3	154.4
Levelized costs EUR/MWh of Liquid fuel	Hydrogen feedstock			Methanol route			CO ₂ captured			CO ₂ emission			Total		
	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate
Fossil diesel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	8.2	137.2	45.2	82.1	220.6
Synthetic Liquid via Methanol (via PEM Electrolysis)	150.6	118.3	125.8	28.0	22.8	41.4	29.6	24.9	12.9				208.2	166.0	180.1
Synthetic Liquid via Methanol (via Alkaline Electrolysis)	128.7	124.3	126.3	28.0	22.8	41.4	29.6	24.9	12.9				186.3	172.0	180.5
Synthetic Liquid via Methanol (via SOEC Electrolysis)	257.8	207.4	151.2	28.0	22.8	41.4	29.6	24.9	12.9				315.4	255.2	205.4
Synthetic Liquid via Fischer-Tropsch (via PEM Electrolysis)	150.6	118.3	125.8	31.4	24.2	18.9	29.6	24.9	12.9				211.6	167.3	157.6
Synthetic Liquid via Fischer-Tropsch (via Alkaline Electrolysis)	128.7	124.3	126.3	31.4	24.2	18.9	29.6	24.9	12.9				189.7	173.3	158.0
Synthetic Liquid via Fischer-Tropsch (via SOEC Electrolysis)	257.8	207.4	151.2	31.4	24.2	18.9	29.6	24.9	12.9				318.8	256.5	182.9
Synthetic Liquid via High temperature co-electrolysis and Fischer Tropsch							54.5	45.9	23.8				219.8	198.9	211.7

Distribution of Hydrogen															
LCOE EUR/MWh distributed hydrogen	Electrolyzer			H2 Compression			H2 pipeline HP			H2 pipeline LP&MP			Total		
	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate
Distribution of gaseous H2	92	89	90	5.9	6.6	7.0	3.8	3.7	3.6	25.2	25.2	25.2	127	125	126
LCOE EUR/MWh distributed hydrogen	Electrolyzer			H2 Liquefaction			Liquid H2 truck and Liquid H2 Tank			Liquid H2 terminal and refuelling			Total		
	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate
Distribution of Liquid H2	92	89	90	13.2	11.9	9.9	3.0	2.8	2.5	20.6	19.6	16.4	129	123	119
LCOE EUR/MWh distributed hydrogen	Electrolyzer			H2 Compression			H2 Tube and H2 pressurized tank			Compressed H2 terminal and refuelling			Total		
	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate	2015	2030	Ulti- mate
Distribution of Compressed H2	92	89	90	5.9	6.6	7.0	19	19	18	14.5	12.9	12.8	132	127	128

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