Power-to-Gas (PtG) in transport
Status quo and perspectives for development

Study in the context of the
scientific supervision, support and guidance of the BMVBS in the sectors Transport and Mobility with a specific focus on fuels and propulsion technologies, as well as energy and climate

Federal Ministry of Transport and Digital Infrastructure (BMVI)

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# Table of Contents

Summary ................................................................................................................................. 4

1 Background and aims of the study .................................................................................. 20

2 Energy policy framework ............................................................................................... 23

3 Power-to-Gas: principles, definitions, development over time ..................................... 26
   3.1 Definition of the term ‘Power-to-Gas’ ...................................................................... 26
   3.2 Principles of Power-to-Gas technology .................................................................. 27
   3.3 Development of Power-to-Gas in transport ............................................................. 30

4 Specific energy use, environmental impacts and costs .................................................. 33
   4.1 Energy chains ......................................................................................................... 33
   4.2 Vehicles ................................................................................................................ 34
   4.3 Results of the fuel chain comparison ...................................................................... 36
   4.4 Hydrogen costs and competitive hydrogen pricing .................................................. 46
   4.5 Profitability of Power-to-Gas .................................................................................. 49
   4.6 Technical potential of CO$_2$ supply from renewable sources .................................. 50

5 Scenarios for the utilisation of PtG in transport ............................................................... 57
   5.1 Background ........................................................................................................... 57
   5.2 Parameters and assumptions ................................................................................ 58
   5.3 Results of the scenario calculations ...................................................................... 61

6 Stakeholders ...................................................................................................................... 69
   6.1 Electricity industry – sufficient potential for energy storage in centralised and distributed settings ........................................................................................................... 69
   6.2 Passenger cars – hydrogen and fuel cells cut energy demand in half .................... 70
   6.3 HDVs – methane offers potential for short-term fuel diversification in long-distance transport ......................................................................................................................... 73
   6.4 Crude oil industry – application of knowledge on process technology .................... 74
   6.5 Natural gas industry – a natural gas grid is already in place, including storage ...... 74
   6.6 Chemical industry – advance hydrogen infrastructure, reduce GHG- emissions ..... 76
   6.7 Aspects of Power-to-Gas utilisation across sectors ................................................ 77

7 Activities ............................................................................................................................ 79
   7.1 Germany .................................................................................................................. 79
7.2 Europe ..............................................................................................................................82
7.3 Global ...............................................................................................................................83

8 Recommendations for action .............................................................................................84
  8.1 Need for R&D ................................................................................................................84
  8.2 Preparation of the market ..............................................................................................86
  8.3 Political measures ..........................................................................................................87

Appendix I: Detailed assumptions on the energy chains investigated in this study ........91
  Petrol and diesel fuel from crude oil .................................................................................91
  CNG from natural gas .......................................................................................................92
  Compressed hydrogen (CGH₂) from steam methane reforming on-site at the
  refuelling station ..............................................................................................................94
  Compressed RE methane from renewable electricity via electrolysis and methanation ....96
  Compressed hydrogen (CGH₂) from renewable electricity via on-site electrolysis
  at the refuelling station .....................................................................................................98
  Compressed hydrogen (CGH₂) from renewable electricity via centralised electrolysis
  at a salt cavern and hydrogen distribution via pipeline ..................................................100

Appendix II: Scenario assumptions .....................................................................................104

Appendix III: Detailed descriptions of demonstration projects .......................................105
  Activities in Germany .......................................................................................................105
  Activities in Europe ..........................................................................................................118
  Activities world-wide .......................................................................................................123

References ..............................................................................................................................127
Summary

Background

The transport sector is dependent on an energy supply distinguished by long-term stability, efficiency and affordability simultaneous emphasising environmental protection and mitigation of climate change. Modern transport is in need of alternatives to fossil, petroleum-based fuels, not least to render the German Energy Transition (Energiewende) a success. For the transport sector, the energy concept of the German Federal Government stipulates targets of a 10% reduction of energy demand by 2020 and 40% by 2050 in reference to the year 2005. In this context, the Mobility and Fuels Strategy (MFS) has identified a number of options that promise to be relevant for energy supply in transport until 2050. One of these options is the Power-to-Gas technology. Its potentials, opportunities and limitations are subjects of this study.

Power-to-Gas (PtG) is defined as the production of a high-energy density gas via electrolysis of water. The first product in this process is power-to-hydrogen which can be subsequently converted to synthetic methane via methanation, a process requiring the feed-in of CO₂. If the processes are carried out exclusively with renewable electricity (RE), the product is labelled renewable Power-to-Hydrogen or renewable Power-to-Methane, respectively. In the context of the increasing implementation of renewable energy, i.e. mainly fluctuating electricity production, PtG may be an option for the transport sector to comply with the targets and goals of the Energy Transition (substantial greenhouse gas reductions, reduction of the dependency on fossil fuels). Increasing vehicle efficiency is still of vital importance, yet efficiency increases alone will not be sufficient in light of the transport growth trajectory predicted, particularly in freight transport.

To date, considerations regarding the transport sector are typically independent from those for other energy systems. This is one of the reasons that the debate on potentials and the temporal or quantitative contributions of different options for the integration of renewable energies is still in its infancy. Furthermore, technological and social innovations in transport and mobility play a pivotal role due to their influence on fuel demand and composition. Transport fuel demand could reinforce current dynamics of the Energy Transition in the electricity sector, thus supporting future renewable electricity implementation with the perspectives of system services provision. Thus, the introduction of PtG into the transport sector could act as a crucial driver and provide leverage for the continued development of (fluctuating) renewable energies in the framework of the Energy Transition.
**Topics and questions addressed**

The findings from the present study aim to contribute to answer questions on how, when and to what extent PtG-derived fuels could be utilised in the transport sector with special attention to their potential impact on climate change and the environment. Furthermore, due consideration is given to the challenges and opportunities for the energy sector associated with the implementation of PtG.

**Results of the scenarios**

The present short study explored three scenarios for road transport and inland navigation in the year 2050:

1. high market penetration with methane-operated internal combustion engines, but no PtG;
2. high market penetration with methane-operated internal combustion engines, fuel demand entirely covered with PtG; and
3. considerable shares of both methane-operated internal combustion engines and fuel cell electric engines, fuel demand entirely covered with PtG.

Despite the projected growth in transport performance and mileage, the final energy demand of the transport modes under investigation is expected to decrease in all three scenarios due to increased engine efficiencies. However, only a shift in focus towards battery or fuel cell electric vehicles will allow to achieve the German Federal Government target, i.e. a 40% reduction of final energy consumption in transport by 2050 in reference to 2005 (-34% in scenario 3). As a consequence, full compliance with the target despite increasing transport performance and mileage would require an ambitious integration of electric vehicles into the fleet.

![Final energy consumption in road transport and inland navigation](image-url)
At the same time, the utilisation of PtG and battery electricity is likely to prompt a shift in energy demand from the vehicle to the electricity/fuel supply pathways. In consequence, the transport sector (excluding aviation, maritime navigation and rail transport) in the scenarios 2 and 3 would be associated with an electricity demand on the same order of magnitude as all other sectors combined (industry, private households, commerce, trade and service sectors).

![Figure: Electricity demand in the scenarios 1–3 (for the demand of the other sectors, the current electricity demand was extrapolated to 2050)](image)

The conservative estimate for the technical sustainable potential of renewable energy produced from wind, photovoltaics, water and geothermal power sources in Germany available for all sectors amounts to approx. 1000 TWh per annum (see MFS study ‘Renewable Energies in Transport’). This amount would be slightly exceeded in scenario 2. In the event that additional subsectors of transport (e.g. PtL fuel for aviation) are to be supplied from renewable energies, future options would in all likelihood include the exploitation of additional energy sources, such as import of renewable electricity or renewable fuels. In scenario 3 with an increased share of battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs), this effect could be mitigated to some degree.

**Energy policy goals**

In the event that by 2050 the majority of road transport with continuously increasing transport performance is operated with PtG energy carriers, increases in the overall electricity demand of about 50% to more than 100% may be the consequence in comparison with current demand levels. Coverage of this electricity demand with renewable energies would be associ-
ated with enormous planning, economic and infrastructure efforts. It is therefore vital to explore all available options for the reduction of energy demand and increase of vehicle efficiencies.

In comparison with the use of methane in internal combustion engines, the use of hydrogen in FCEVs is distinctly more energy-efficient for technological reasons. This would promote a more efficient utilisation of renewable energies. However, today hydrogen and fuel cells are associated with further technological development needs and the need of economies of scale both for vehicles and infrastructure compared to current systems. Concluding, future energy policy measures should favour renewable hydrogen in FCEVs over the utilisation of renewable methane in internal combustion engines, particularly in settings that do not allow for the operation of BEVs.

Development of the electricity grid alone is unlikely to be sufficient to achieve full supply with renewable energies in Germany in the long-term. Energy storage capacities in batteries (short-term storage) and in the form of PtG for longer-term storage will be required as additional options. In the medium-term, energy service providers regard PtG as an option for mitigating grid bottlenecks which, for instance, may currently arise from poor public acceptance of grid development efforts. Renewable electricity fuel production may support the electricity system by providing grid services in the medium- and long-term in both centralised and distributed conceptual approaches.

**Climate goals**

The scenario analysis in this study reveals that even considerable efficiency increases, particularly for passenger cars with internal combustion engines (scenario 1), will merely result in greenhouse gas (GHG) emission reductions of about 24% between 2010 and 2050.

Moreover, the scenario results illustrate that utilisation of fossil energy-based hydrogen from natural gas with application in FCEVs may reduce GHG emissions of passenger cars by almost 25% compared with the direct utilisation of natural gas in internal combustion engine vehicles (CNG). The energy requirements of steam methane reforming are overcompensated by the high efficiency of fuel cells. However, for long-distance heavy-duty vehicles (HDVs), this advantage is reduced to about 5% due to the high efficiency of diesel-fuelled engines over long distances. However, it should be noted that this pathway is associated with considerable investments into steam methane reforming facilities and its profitability is linked to the natural gas price trajectory. Moreover, potential greenhouse gas reductions are limited when using fossil natural gas compared to those of renewable energy pathways.
The application of PtG technology in 2050 in scenario 2 (methane-operated internal combustion engines, energy demand covered entirely with PtG from renewable electricity) is associated with a GHG emission reduction of 73% in reference to 1990. An additional decrease in electricity demand due to a broad implementation of BEVs and FCEVs (scenario 3) operated with 100% renewable energy results in GHG emissions reduced by about -82% in reference to 1990. The remaining emissions are caused by the operation of vehicles powered by fossil fuels.

Figure: GHG emissions in road transport and inland navigation

CO₂ required for methanation may be obtained from biogenic or industrial processes, or via extraction from ambient air with additional energy efforts. The current annual theoretical CO₂ potential in Germany amounts to approx. 17 million t (biogenic) or 20 million t (from industrial processes). Thus, approx. 185 TWhₗₙₑₙₑ methanee could be generated. This output has to be seen in contrast to a demand for renewable Power-to-Methane of 350 TWhₗₙₑₙₑ in scenario 2 or 140 TWhₗₙₑₙₑ in scenario 3, respectively. It is evident that the CO₂ demand in a transport scenario dominated by renewable methane (scenario 2) distinctly exceeds the available CO₂ supply (biogenic and industrial). As a consequence, additional CO₂ potentials would have to be developed, e.g. by extracting CO₂ from ambient air.
Costs

The analyses in Chapter 4 reveal that the utilisation of PtG is associated with two decisive cost factors, namely electrolysis investment costs and the costs for electricity. In the medium-term, an economically attractive production of hydrogen from PtG for the transport sector appears feasible. Thus, hydrogen could act as a driver for PtG, promoting technologies and development of the electrolysis infrastructure. Due to the fact that cost recovery of PtG in transport is going to be achieved earlier than in other sectors, the development of hydrogen and methane production could accelerate economies of scale, which in turn could be to the benefit of other sectors.

In principle, the CO$_2$ neutral production is one of the advantages of power-to-methane as an alternative fuel option. However, as long as this benefit is not reflected in the pricing, no single PtG application can contribute to establish a market. This correlation equally applies to the transport sector: the profitability of methane pathways from PtG compares unfavourably to that of hydrogen from PtG across all fields of application due to substantial efficiency losses along the supply chain from renewable electricity to the kilometre driven. In the case of methane production from PtG, the unlimited use of existing natural gas infrastructure is a clear advantage. In contrast, the distribution of hydrogen would require an infrastructure development almost from the ground up.

Following the German Energy Economy Act (Energiewirtschaftsgesetz) §118 Absatz 6, PtG plants generating hydrogen via electrolysis of water, or methane via electrolysis and subsequent methanation, have been exempted from grid use fees for the next 20 years. In contrast to other storage technologies, there is no requirement to return absorbed electric energy back to the grid. Furthermore, according to §9a of the German Electricity Taxation Act (Stromsteuergesetz), electricity consumed for electrolysis is exempt from energy taxation. At present, both exemption from end user fees as well as a financial reflection of potential flexibility services PtG installations are prerequisites for any potential business opportunities. Thus, PtG technology could make relevant contributions to the reduction of greenhouse gas emissions. Looking ahead, the further development of facilities for the production of renewable electricity is inevitable. In principle, the transport sector may be expected to contribute to the funding of those facilities as appropriate to support its specific needs.
Key messages on the perspectives for PtG

The results of this study reveal PtG as a favourable option to achieve the following policy goals in the transport sector:

- diversification of the primary energy basis, thus reducing dependency on petroleum imports,
- significant reduction of GHG emissions,
- introduction of renewable electricity into the transport sector,
- facilitation of market penetration with alternative drive trains,
- taking advantage of the current dynamics of the Energy Transition, coupled with additional long-term support potential for the Energy Transition through provision of system services.

In the near to mid-term, the exploitation of PtG potentials in the transport sector is associated with three main fields of action:

1. Firstly, to achieve technological maturity, targeted research, development and validation is required.
2. Secondly, a successful development of the market needs to be preceded by the identification of economically attractive applications for PtG technology. Business models giving consideration to synergies with other energy sectors should be developed.
3. Thirdly, the policy framework should be adapted to support business models that aim to promote goals of the political agenda regarding PtG.

From an energy system angle, clear preferences for the application of PtG are identified:

- Among the options for long-term energy storage, only chemical energy storage in the form of hydrogen or methane has sufficient potential to make available stored energy in the required quantities given a high share of renewable energies in the grid.
- In the medium-term, PtG offers business opportunities for the application of hydrogen as a fuel for the transport sector only. In all other sectors (electricity, gas, industry, methane as fuel) PtG is unlikely to be an economic option even in the long-term.
- In consequence, the transport sector plays a pivotal role as a forerunner and initiator for hydrogen-based PtG pathways as well as for the establishment of the corresponding hydrogen infrastructure. The overall energy systems and all energy sectors are likely to benefit from such development.
R&D

- Efforts to improve efficiency and reduce costs of different electrolysis techniques should be systematically pursued.
- To promote user acceptance, a greater diversity of CNG vehicle models available as well as the continued development of HDV engines are required.
- Technical regulations, codes and standards for grid operation should be revised and adapted where applicable, particularly to allow hydrogen feed-in into the natural gas grid as well as the operation of individual grid parts with fluctuating hydrogen blend quotas.

Preparation of the market

- Preparation of the market requires additional detailed economic analysis exploring the application of hydrogen in different markets.
- Economic analyses should pay special attention to the assessment of indirect effects of PtG (e.g. provision of grid services) as currently, relevant data are scarce.
- Dialogue between relevant stakeholders should be further advanced to identify synergies early on and promote cooperation among them.
- Another crucial pillar may be found in distributed PtG concepts, e.g. directly located at hydrogen refuelling stations. Moreover, distributed solutions offer opportunities for renewable electricity integration at low-voltage distribution grid level and may be utilised for the supply of distributed stationary applications.
- In addition to the technical questions, relevant business models need to be developed, particularly for the initiation, development and operation of PtG infrastructure (grid and refuelling stations).
- Synergies and funding sources must be assessed to identify opportunities for shared infrastructure investments already planned in the medium-term, e.g. in the context of the EU Directive Clean Power for Transport.
- In this context it is vital to utilise established structures for European cooperation (Hydrogen Infrastructure for Transport – HIT) and international cooperation (International Partnership for Hydrogen in the Economy – IPHE). A German national stand-alone effort for the establishment of a hydrogen refuelling station infrastructure will be prone to failure.
Policy measures

- Development of a PtG roadmap across sectors to identify economic options for shared use of hydrogen infrastructure revealing the required quantity and cost structures.
- Integration of PtG into fuel legislation.
- The scope of a PtG strategy for the transport sector based on renewable energies should seek an upward adjustment of existing national development targets for renewable electricity. Furthermore, mechanisms enabling the coupling of renewable energy development to PtG fuel demand in transport should be devised.
- Commitment to unambiguous, binding targets for GHG emissions reductions in the transport sector in the period up to 2050 (as already established in other sectors).
- Mandatory requirements for PtG fuels versus reference fuels with regard to GHG emission reductions.
- Special benefits or incentives, e.g. for market preparation purposes (such as multiple crediting towards the biofuel quota) should be designed degressively and adjustable, and should be applied for a limited period of time only.
- Multiple crediting of PtG fuels: the EU Renewables Directive (RED) seeks to achieve a 10% share of renewables of the final energy consumption in transport by 2020. In case of multiple crediting of PtG fuels under this quota, the credited PtG quantity should be determined equivalent to the share of renewable electricity used. Furthermore, hydrogen and methane have to be considered separately. In the case of hydrogen, multiple crediting can be justified by the higher efficiency of fuel cell engines.
- Communication on political levels should seek to establish cooperation with other countries with similar conditions for PtG establishment or similar general interests (e.g. the Netherlands in Europe and internationally Japan).

A successful PtG strategy requires securing:

- an optimal mix of BEVs, FCEVs and conventional vehicles under consideration of financial, environmental and user aspects;
- the availability of required renewable supply capacities (under economically, technologically and ecologically sustainable conditions, considering both domestic production and imports);
- the coverage of arising electricity demand with renewable energies wherever possible (even minor contributions of fossil electricity may impair the climate balance considerably), as well as
- promotion of additional measures for the reduction of transport energy demand (such as logistical optimisation and reduction of transport volumes).
List of Figures

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Figure 1:</td>
<td>Feed-in levels of renewable power plants installed in Germany (Source: LBST based on [DGS 2014])</td>
<td>24</td>
</tr>
<tr>
<td>Figure 2:</td>
<td>Illustration of PtG and PtL energy chains</td>
<td>27</td>
</tr>
<tr>
<td>Figure 3:</td>
<td>Illustration of energy flows for the utilisation of PtG in different energy sectors (Source: LBST)</td>
<td>28</td>
</tr>
<tr>
<td>Figure 4:</td>
<td>Fuel supply pathways explored in this study</td>
<td>34</td>
</tr>
<tr>
<td>Figure 5:</td>
<td>Primary energy use of LDVs well-to-wheel, 2030 (for details see Appendix)</td>
<td>37</td>
</tr>
<tr>
<td>Figure 6:</td>
<td>Primary energy use of HDVs well-to-wheel, 2030 (for details, see Appendix)</td>
<td>38</td>
</tr>
<tr>
<td>Figure 7:</td>
<td>Greenhouse gas emissions from LDVs well-to-wheel, 2030 (based on: renewable electricity, for details see Appendix)</td>
<td>39</td>
</tr>
<tr>
<td>Figure 8:</td>
<td>Greenhouse gas emissions well-to-wheel HDVs, 2030 (based on: renewable electricity, for details see Appendix)</td>
<td>40</td>
</tr>
<tr>
<td>Figure 9:</td>
<td>Greenhouse gas emissions well-to-wheel per km for LDVs in correlation with electricity mix or associated CO₂ intensity</td>
<td>41</td>
</tr>
<tr>
<td>Figure 10:</td>
<td>Acidification potential resulting from SO₂ and NOₓ emissions from LDVs well-to-wheel, 2030</td>
<td>43</td>
</tr>
<tr>
<td>Figure 11:</td>
<td>Acidification potential resulting from SO₂ and NOₓ emissions from HDVs well-to-wheel, 2030</td>
<td>43</td>
</tr>
<tr>
<td>Figure 12:</td>
<td>Fuel production costs for LDVs well-to-wheel, 2030</td>
<td>45</td>
</tr>
<tr>
<td>Figure 13:</td>
<td>Fuel production costs for HDVs well-to-wheel, 2030</td>
<td>45</td>
</tr>
<tr>
<td>Figure 14:</td>
<td>Hydrogen production costs for 2030 and cost ranges for competing solutions by market sector from Table 2</td>
<td>49</td>
</tr>
<tr>
<td>Figure 15:</td>
<td>Sites of biogas upgrading and feed-in facilities in operation in Germany including upgrading capacity (Nm³biomethane/h) [DBFZ et al. 2013]</td>
<td>53</td>
</tr>
<tr>
<td>Figure 16:</td>
<td>Regional distribution of solid biomass CHP plants and wood gas generators by postal area code in Germany [DBFZ et al. 2013]</td>
<td>55</td>
</tr>
<tr>
<td>Figure 17:</td>
<td>Final energy consumption in road transport and inland navigation</td>
<td>62</td>
</tr>
</tbody>
</table>
Figure 18: Electricity demand of the scenarios 1–3. For the demand of the other sectors, the current electricity demand was extrapolated to 2050........63

Figure 19: GHG emissions from road transport and inland navigation ..................65

Figure 20: Map of Power-to-Gas projects in Germany (Source: LBST)...................81

Figure 21: General structure of a CGH₂ refuelling station ....................................95

Figure 22: Electrolyser at power plant Niederaußem, Germany (Source: RWE) ....106

Figure 23: Compact biogas plant 'EUCOline' in Schwandorf
(Source: MicrobEnergy GmbH) ........................................................................107

Figure 24: PtG plant at the ZSW in Stuttgart, Germany (Source: ZSW Stuttgart) ..109

Figure 25: ENERTRAG PtG plant in Prenzlau, Germany (Source: ENERTRAG) ....111

Figure 26: Hydrogen refuelling station with PV in Freiburg, Germany
(Source: LBST) ........................................................................................................117

Figure 27: PtG plant in Corsica, France
(Source: McPhy Energy, Photo by: Sebastien Aude, Balloide Photo) ........120
List of Tables

Table 1: Fuel consumption and emissions of vehicles tank-to-wheel 2025-2030 ......36
Table 2: Competitive hydrogen production costs for different markets ....................47
Table 3: Estimate of theoretical CO₂ potentials from biogas in Germany based on existing stock in 2012 .................................................................52
Table 4: Estimate of theoretical CO₂ potentials from biomass CHP plants based on the existing stock in 2012 ...............................................................54
Table 5: CO₂ from industrial processes (million t/a) .............................................56
Table 6: CO₂ potentials and resulting potentials for synthetic methane production in Germany .................................................................56
Table 7: Assumptions on fleet structure and energy carriers utilised ........................59
Table 8: Energy carrier shares of mileage (passenger cars) or transport performances (HDVs and inland vessels) in the scenarios .................60
Table 9: PtG share in the scenarios .......................................................................60
Table 10: Energy use and emissions from petrol and diesel supply from crude oil in 2010 ..................................................................................91
Table 11: Costs for petrol and diesel fuel (excl. tax) .............................................92
Table 12: Energy flows and emissions from natural gas production and upgrading ....92
Table 13: Technical and economic data for a typical CNG refuelling station ..........93
Table 14: Energy flows and emissions from hydrogen production via steam methane reforming ...........................................................................94
Table 15: Technical and economic data for a CGH₂ refuelling station (in combination with on-site steam methane reforming) .........................96
Table 16: Energy and material flows for the production of methane from H₂ and CO₂ .98
Table 17: Technical and economic data for a typical CGH₂ refuelling station (in combination with on-site electrolysis) ..............................................100
Table 18: Technical and economic data for a typical salt cavern including facilities above ground .................................................................................101
Table 19: Technical and economic data on H₂ pipeline grid ................................102
Table 20: Technical and economic data for a typical CGH₂ refuelling station (in combination with H₂ delivery via pipeline) ...............................103
Table 21: Hydrogen refuelling stations in operation in Europe (excl. Germany) with on-site hydrogen production

Table 22: Hydrogen refuelling stations in operation world-wide (excl. Europe) with on-site hydrogen production
Abbreviations

bbl  barrel (of crude-oil)
BEV  Battery electric vehicle
CGH₂  Compressed gaseous hydrogen
CHP  Combined heat & power
CH₄  Methane
CNG  Compressed natural gas
CO  Carbon monoxide
CO₂  Carbon dioxide
DC  Direct current
DE  Diesel equivalent
€/kg₂H₂  Euro per kilogramme of hydrogen
FCEV  Fuel cell electric vehicle
g CO₂ eq/kWh  Representative of climate-harming emissions as CO₂-equivalent emissions per kilowatt-hour
GHG  Greenhouse gas
GJ  Gigajoule (= 1 billion Joule)
GVW  Gross vehicle weight
GWh  Gigawatt hour (= 1 million kWh)
H₂  Hydrogen
HDV  Heavy-duty vehicle¹
HIT  Hydrogen Infrastructure for Transport (TEN-T Program)
HTE  High-temperature electrolysis (steam electrolysis)
IFEU  Institut für Energie- und Umweltforschung Heidelberg
km  Kilometre

¹ WtW analyses in this study assumed a GVW of 40 t for HDVs, scenarios included all HDVs of the N3 category with GVWs ranging between 12–40 t.
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>kWh</td>
<td>Kilowatt hour</td>
</tr>
<tr>
<td>LBST</td>
<td>Ludwig-Bölkow-Systemtechnik</td>
</tr>
<tr>
<td>LDV</td>
<td>Light-duty vehicle (i.e. passenger cars and small panel vans)</td>
</tr>
<tr>
<td>LHV</td>
<td>Lower heating value</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied natural gas</td>
</tr>
<tr>
<td>MFS</td>
<td>Mobility and Fuels Strategy</td>
</tr>
<tr>
<td>MJ</td>
<td>Megajoule (= 1 million Joule)</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour (= 1000 kWh)</td>
</tr>
<tr>
<td>NEDC</td>
<td>New European Driving Cycle</td>
</tr>
<tr>
<td>Nm³</td>
<td>Standard cubic metre</td>
</tr>
<tr>
<td>NMVOC</td>
<td>Non-methane volatile organic compounds</td>
</tr>
<tr>
<td>NOₓ</td>
<td>Nitric oxides</td>
</tr>
<tr>
<td>N₂O</td>
<td>Nitrous oxide</td>
</tr>
<tr>
<td>PEM</td>
<td>Proton exchange membrane</td>
</tr>
<tr>
<td>PtCH₄</td>
<td>Power-to-Methane</td>
</tr>
<tr>
<td>PtG</td>
<td>Power-to-Gas</td>
</tr>
<tr>
<td>PtH₂</td>
<td>Power-to-Hydrogen</td>
</tr>
<tr>
<td>PtL</td>
<td>Power-to-Liquids</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>RE PtCH₄</td>
<td>Renewable Power-to-Methane</td>
</tr>
<tr>
<td>RE PtH₂</td>
<td>Renewable Power-to-Hydrogen</td>
</tr>
<tr>
<td>RE</td>
<td>Renewable electricity</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam Methane Reforming</td>
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<td>SNG</td>
<td>Synthetic Natural Gas</td>
</tr>
<tr>
<td>SO₂</td>
<td>Sulphur Dioxide</td>
</tr>
<tr>
<td>t</td>
<td>Metric ton</td>
</tr>
<tr>
<td>TREMOD</td>
<td>Transport Emission Model</td>
</tr>
<tr>
<td>TWh</td>
<td>Terawatt hour (= 1 billion kWh)</td>
</tr>
<tr>
<td>VDE</td>
<td>German Association for Electrical, Electronic &amp; Information Technologies</td>
</tr>
<tr>
<td></td>
<td>Description</td>
</tr>
<tr>
<td>----</td>
<td>-----------------</td>
</tr>
<tr>
<td>vol%</td>
<td>Percent by volume</td>
</tr>
<tr>
<td>WtT</td>
<td>Well-to-Tank</td>
</tr>
<tr>
<td>WtW</td>
<td>Well-to-Wheel</td>
</tr>
</tbody>
</table>
1 Background and aims of the study

Background

Only in recent years has the energy sector begun to focus on the subject of energy storage as a means of extended flexibility for the introduction of renewable, i.e. fluctuating, electricity. Among the initiators was the VDE study on energy storage [VDE 2008]. This study established high-energy density gases and hydrogen in particular as the only storage means with sufficient potential for the storage of substantial quantities of excess electricity production over periods of several weeks. After 2011, the announcement of ambitious development plans for renewable energies (RE) by the German Federal Government prompted PtG technology with electricity storage in the form of hydrogen and/or synthetic methane to become the focus of a number of in-depth analyses [dena 2012], [ISE 2012], [ISE 2013], [VKU 2013], [Bayern 2013], [IWES 2014]. The transport sector has not been given any specific attention to date in any of the analyses, in particular due to the fact that the terms ‘Power-to-Gas’ and ‘Power-to-Methane’ are used as synonyms [Öko-Institut 2014].

It was only later, in the context of multiple system studies, that PtG was identified as a relevant short-term business opportunity for utilisation as fuel in the transport sector. Both the utilisation of methane gas in the form of CNG in natural gas-fuelled vehicles equipped with internal combustion engines and hydrogen in fuel cell electric vehicles (FCEVs) were investigated. Both concepts are currently explored in numerous demonstration projects primarily located in Germany.

Thus, the potential relevance of PtG across the entire energy market was realised. Joint utilisation of natural gas and hydrogen infrastructure may even attribute the PtG process the role of a crucial link between energy sectors. Similar to the currently widespread application of methane in form of natural gas, the energy sectors of the future may utilise hydrogen from renewable electricity. In other words, hydrogen could become universally attractive as a potential fuel, chemical feedstock, for cogeneration concepts via fuel cells or for the provision of private households with electricity and heat.

However, the PtG concept is not a complete novelty for the transport sector, albeit not in the current terminology. In transport, the application of renewable electricity via electrolysis to produce hydrogen as gaseous fuel for the operation of high-efficiency FCEVs has already been part of the Mobility and Fuels Strategy of the German Federal Government for a number of years [MKS 2004].
Objective

The present study aims to promote a better understanding of the technological and economic parameters, environmental impacts and potentials of the application of PtG in the transport sector comparing the two available options hydrogen and synthetic methane. Similar to other fuel or engine alternatives, the reasons for the application of PtG in the transport sector are derived from the following political objectives:

- Reduction of mobility dependency on primarily imported crude oil and
- Compliance with greenhouse gas reduction targets in transport under assumption of substantial projected growth trajectories, particularly in freight transport.

Given the increasing scarcity of energy and material resources, these objectives are inextricably linked with the efficient use of renewable electricity as a resource.

The present study explores the application of hydrogen and synthetic methane gas from PtG with a special focus on mobility. Differences in the application of PtG in other energy sectors are considered where applicable. Thus, this study explores the following questions:

- What are the costs associated with hydrogen and methane production from PtG in 2030 (earliest broad market launch) in comparison with reference system costs?
- How do fuel production costs per kilometre for passenger cars and heavy-duty vehicles (HDVs) compare for operation of hydrogen-fuelled FCEVs and methane-fuelled internal combustion engines?
- Which environmental impacts are associated with the production and utilisation of hydrogen and methane in comparison with diesel and petrol or CNG?
- What are the consequences of continued use of hydrogen and methane from electricity for overall electricity demand and greenhouse gas emissions in Germany?
- Which stakeholders within the energy and transport sectors have shown interest in the subject of PtG, and what contributions could these parties make?
- In comparison with the situation in other countries, which activities, i.e. demonstration projects, are currently under way in Germany and which role does Germany play concerning PtG in transport?
- Which specific recommendations for action may be derived from the analyses above?

The analyses presented here were based on the current state of the art in industry and science, identifying the need for additional research or recommending strategies for action where appropriate.

Chapter 3 provides an introduction to terminology and history, followed by a presentation of the technological and economic status quo including an environmental impact analysis for passenger cars and HDVs in reference to conventional energy carriers in Chapter 4.
Chapter 5 assesses the impacts of increased PtG use in transport on electricity demand and GHG emissions in several scenarios. Current views on PtG by relevant stakeholders (Chapter 6) are followed by a presentation of current pilot projects (Chapter 7), concluding with recommendations for action in science, economy and politics (Chapter 8).
2 Energy policy framework

An energy system dominated by fluctuating renewable energy sources is faced with the challenge of balancing energy supply and demand. Power-to-Gas (PtG) may play a pivotal role due to its inherent qualities such as flexible production and storage capacity. PtG is particularly suitable for long-term storage and thus for the balancing of long-term fluctuation in overall energy supply.

At what point does Power-to-Gas in the grid qualify as a favourable storage option?

Available simulations of the electricity grid modelling different levels of renewable energy utilisation reveal a requirement for long-term storage of electricity only in the case of high shares of renewable energies (from approx. 60-70%) [VDE 2012], [DLR 2012], [NEP 2013]. However, these models are based on simplified assumptions (e.g. grid modelled as a copper plate, focus on transmission network level, sole consideration of the electricity sector excluding links to other consumer sectors such as fuel production for transport).

The debate on potentials and associated temporal and quantitative contributions of different possible options for RE integration is in its infancy. Currently opposing estimates are expected to converge in the foreseeable future only if a common consensus on medium to long-term RE development targets may be established. Technological and social innovation in transport and mobility are expected to play a major role in this context due to their potential influence on fuel demand and composition. There is evidence that in the short-term, the integration of fluctuating renewable energies through measures such as grid expansion, demand side management and energy storage could extend the scope of operating inflexible thermal power plants and electricity trading [VDE 2012], [Gerbaulet 2013], [eclareon 2012]. However, in-depth analyses of grid expansion trajectories are not subject of the present study. Therefore, we adopt results for the BMU-Leitstudie 2011 [DLR 2012].

According to the Energy Concept of the German Federal Government, a share of 65% of renewable energies in the grid is intended for the year 2040. The BMU-Leitstudie 2011 (scenario A) projects the achievement of this goal around ten years earlier. From the perspective of the German electricity system as a whole, demand for long-term storage capacity (covering periods of weeks or months) is unlikely to act as a driver for the application of PtG technology over the next 20 years. At the same time, excess electricity is already a common occurrence in the production of renewable electricity negatively impacting the energy exchange rate. However, economically feasible production of PtG in the electricity sector is currently out of the question due to limited excess electricity and low guaranteed capacity (see Chapter 4). In this context, the question arises whether demand for hydrogen or methane from the
transport sector could act as a driver for the implementation of PtG (primarily due to differences in cost structures in transport). Moreover, synergies with the electricity sector could be exploited.

The analyses in Chapter 4 reveal profitability of fuel production from PtG for the transport sector in the medium-term. The economic benefits associated with PtG may act as drivers for technologies and the development of electrolysis infrastructure.

However, economic operation of electrolysers requires a minimum of 3000 to 5000 full load hour equivalents (cf. [DVGW 2013-1]). The sole use of ‘excess electricity’ (with very low or negative electricity prices) will be insufficient for this purpose. High electrolyser loads at economically relevant prices may be achieved with the purchase of energy exchange electricity during periods of low pricing. These periods usually correlate with high shares of renewable energy, thus promoting RE integration.

**Storage infrastructure particularly attractive for the electricity distribution grid**

From a technological viewpoint, distributed exploitation of PtG is particularly favourable due to the fact that over 90% of fluctuating RE electricity production capacity is connected to the distribution grid (see Figure 1). In a concerted effort with other RE integration measures, PtG may ease the pressure on distribution and higher-level transmission grids. Such distributed PtG production sites could provide future perspectives for local fuel production.

![Image: Feed-in levels of renewable power plants installed in Germany](data:image/png;base64,iVBORw0KGgoAAAANSUhEUgAAA...)

**Figure 1:** Feed-in levels of renewable power plants installed in Germany (Source: LBST based on [DGS 2014])
Preference of direct electricity utilisation over intermediate storage

The energy efficiency of direct utilisation of renewable electricity without intermediate storage or intermediate stages and its application in battery electric vehicles (BEVs) is distinctly higher. In consequence, direct utilisation is preferable to intermediate storage. However, future BEVs are expected to continue to be unsuitable for long-distance and heavy-duty transport. For these subsectors, PtG (hydrogen or methane) may be a convenient solution that is being advanced but the automotive industry (see subchapter 3.3).

High greenhouse gas savings and high transport performance unfeasible without PtG

Transport is the only sector associated with significant increases in GHG emissions over the past 20 years. The principal reason for this is the overall increase in road freight transport with further growth expected in the future [Intraplan 2007]. In this context, transport performance is mainly defined as long-distance road freight transport that remains unsuitable for electrification with batteries in the foreseeable future for energy storage density reasons.

PtG from renewable electricity, for instance via methane/LNG, could qualify as a solution for these technological challenges for the HDV sector in particular. PtG may be a key strategy enabling the freight sector to contribute to the realisation of the climate change mitigation goals of the German Federal Government (GHG savings -55% in 2030 and -80% in 2050 in reference to 1990).
3 Power-to-Gas: principles, definitions, development over time

In June 2013, the ‘Mobility and Fuels Strategy (MFS) – New pathways for energy’ of the German Federal Government specified the following renewable fuel options as promising [MKS 2013]:

- Sustainable biofuels (limited by potential),
- Electricity (in battery electric or battery plug-in hybrid vehicles),
- Hydrogen from electricity (in FCEVs),
- Methane from electricity (in internal combustion engines in combination with natural gas – CNG for passenger cars, buses and HDVs as well as LNG for HDVs and ships) and
- Electricity-derived liquid fuels (Power-to-Liquids).

The list of these fuels is based on findings from the first Mobility and Fuels Strategy of the German Federal Government [MKS 2004]. The relevance of renewable energies (electricity and biomass) as an important future option is evident.

3.1 Definition of the term ‘Power-to-Gas’

The study was based on the following definitions:

- **Power-to-Gas (PtG):** Production of a high-energy density gas via the electrolysis of water. The first intermediate product is Power-to-Hydrogen (PtH₂) that may be converted into synthetic methane gas Power-to-Methane (PtCH₄) in a subsequent methanation process requiring the feed-in of CO₂. In the case that exclusively renewable electricity is used, the product is labelled RE PtH₂ or RE PtCH₄.

- **Power-to-Liquids (PtL):** Production of liquid carbon based energy carriers from electricity via the electrolysis of water. Hydrogen is the intermediate product and is further converted in a consecutive synthesis from synthesis gas by adding CO₂ to synthetic gasoline (PtGasoline), Diesel fuel (PtDiesel) or kerosene (PtKerosene).

In principle, the term PtG does not convey any information on the origins of electricity used for the production of hydrogen and subsequently methane. To emphasise the fact that PtG is particularly relevant for energy systems primarily based on renewable electricity, Figure 3 exclusively focuses on renewable pathways for Power-to-Hydrogen and Power-to-Methane. The required electricity may be produced and utilised locally (on-site) or certified green electricity is applied.
3.2 Principles of Power-to-Gas technology

The principles and energy flows for the production and utilisation of PtG are illustrated in Figure 3. The process is divided into the stages ‘gas production (Power-to-Gas)’, ‘gas infrastructure’ and ‘gas utilisation’.

The production of hydrogen and methane from renewable electricity reflects the achievement of the long-term goal of future GHG-neutral supply of gaseous or liquid energy carriers or fuels. In contrast to renewable Power-to-Methane, the term ‘Power-to-Methane’ is applied to a product synthesised under application of grey electricity produced by conventional plants with fossil or nuclear input. The same principle applies to (renewable) Power-to-Hydrogen. The advantage of PtG approaches over direct electricity utilisation lies in the superior capacity of high-energy density gases, i.e. for longer periods of time and high energy density. In consequence, hydrogen and methane are sometimes labelled storage gases. An overview of the principal electricity-based fuel supply options and the integration of PtG is given in Figure 2.

**Figure 2:** Illustration of PtG and PtL energy chains

Nonetheless, during the initial PtG introduction period, the use of non-renewable electricity may be relevant to facilitate an affordable development of key infrastructure, thus ensuring the minimum required load for an economic electrolyser operation. However, in that case environmental impact analysis needs to consider fossil supply pathways, e.g. if electricity is supplied by the public grid (grey electricity) and billed according to energy exchange prices. The shares of renewable electricity must be documented for verification.

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\(^{2}\) In principle, it may be expected that favourable energy exchange prices important for the economic operation of PtG are bound to coincide with periods of oversupply of renewable electricity. However, to prevent a shift in the balance from RE electricity to PtG production, additional criteria are required.
3.2.1 Electrolysis

Electrolysers are the key technology for the concept of PtG due to their role in the production of hydrogen from electricity. In principle, several concepts are available for the catalytic decomposition of water into hydrogen and oxygen under application of an electric current. The best tried and tested technology is alkaline electrolysis (AEL) carried out at low temperatures (< 100 °C) and moderate pressure (atmospheric … 3 MPa). The AEL process is robust and affordable, yet start/stop operation and increased dynamics require adjustments based on the requirements of individual projects.

A promising alternative for high energy density and consequently, reduced space requirements for installation, considerable system dynamics and low series manufacturing costs (due to synergies with PEM fuel cells) may be realised by applying PEM electrolysis technology (PEMEL = proton exchange membrane electrolysis). PEM electrolysis also operates at low temperatures, yet the pressure applied may be slightly higher (< 10 MPa). This technology particularly recommends itself for on-site operation at refuelling stations or distributed PtG concepts due to modest space requirements, notable tolerance towards dynamic energy sources and its modularity. However, mature technology with low-cost series manufacturing is not expected before 2020.
In contrast, high-temperature electrolysis (HTE or steam electrolysis) is still at a R&D stage. Operation of HTE is highly energy-efficient when high-temperature waste heat is available in excess. In consequence, very cost-effective operation may be possible under these constraints. High-temperature processes are frequently found in fossil, nuclear or concentrated solar power (CSP) plants. However, these operations are unlikely to play a major role in future renewable electricity production. For these reasons, HTE was excluded from the present study.

Again, the production of hydrogen is unique to all PtG pathways. The material and economic aspects of the electrolysis by-product oxygen are usually ignored due to the fact that oxygen transport is generally considered expensive. However, utilisation of by-product oxygen may in some cases be associated with economic benefits, for instance in sewage treatment plants as a substitute for oxygen from air separation.

3.2.2 Infrastructure

The element essential to all PtG concepts is the gas infrastructure. Its purpose is either the transport of pure hydrogen in dedicated hydrogen grids, or the blending of hydrogen (up to certain limits in the blend) or synthetic methane into existing infrastructure for transport, distribution or storage of natural gas. Figure 3 summarises the infrastructure pathways for hydrogen and synthetic methane simplifying them into one pathway for ‘storage gas’.

The blending of hydrogen into the existing natural gas grid is currently only partly feasible, i.e. for limited quantities with low fluctuations to avoid local H\textsubscript{2} concentration peaks. At present, maximum blends of 2-10 vol\% are being considered. Some facilities such as porous reservoirs or gas turbines may be unsuitable for H\textsubscript{2} utilisation altogether [DVGW 2013-3]. In principle, higher blend quotas are feasible assuming adequate upgrading measures. This was demonstrated in the nationwide utilisation of coal gas with > 50% H\textsubscript{2} content in Western and Eastern Germany in the 1950s.

The transport of pure hydrogen in pipelines or pipeline systems in Germany is limited to an established infrastructure for industrial hydrogen. Such infrastructure is found in North Rhine-Westphalia (240 km), in the industrial region of Leuna/Bitterfeld (135 km) and in Schleswig-Holstein (Heide/Brunsbüttel) (43 km) [R2H 2007], [ChemCoast 2013]. The conversion of former natural gas distribution grid segments for operation with 100% hydrogen has not been investigated in great detail [SWM 1999], [NaturalHy 2007], [Lolland 2013]. However, such rededication may become increasingly relevant in an energy system with growing distributed energy production. Additional analyses and field studies are needed here.

Concluding, PtG via natural gas and hydrogen infrastructures would essentially be available for the electricity sector (bulk storage demand, control energy market), chemical industry
(demand for green hydrogen, supply of existing hydrogen pipe infrastructure and storage) and for the energy supply of the transport sector.

3.3 Development of Power-to-Gas in transport

This chapter provides a brief overview of the trajectory of the use of gaseous alternative fuels (methane/natural gas and hydrogen) for mobility purposes that were instrumental in the development of the vehicles and infrastructure currently available. Two separate technology pathways are pursued for the transport sector:

- **Methane**: The short-term relevance of natural gas in road transport in the form of compressed methane (CNG) was already established in the first Mobility and Fuels Strategy of the German Federal Government [MKS 2004]. Potential utilisation of methane via PtG in CNG vehicles thus represents an obvious extension of this option. Overall, the same technological requirements apply for vehicles operated with natural gas or synthetic methane gas.

- **Hydrogen**: The production of hydrogen via electrolysis and renewable electricity with subsequent use in transport, particularly in fuel cells, have been recognised by German automotive and energy industries as a relevant long-term solution since 2001 [VES 2001]. However, early on, the term PtG was not applied in this context. Additional hydrogen sources explored included steam methane reforming or biomass gasification. In the long-term, only the production of hydrogen from renewable energies remains on the agenda.

3.3.1 Vehicles

**Natural gas vehicles**

Natural gas vehicles are currently available on the market with about 96,500 vehicles in operation in Germany [GVR 2013]. However, it was not until 2012 that AUDI proposed the operation of CNG vehicles with methane from renewable electricity via PtG [Schober 2012]. This concept is currently explored in a PtG demonstration project in Werlte under participation of AUDI. The synthetic methane gas generated by the PtG plant (based on biomass) is fed into the existing gas grid and marketed as an emission-free option for CNG-fuelled internal combustion engine vehicles.
**Fuel cell electric vehicles (FCEVs)**

After many years of research on the development of internal combustion engine vehicles fuelled with hydrogen (e.g. [Feucht 1998]), Daimler commenced to explore the technological feasibility of fuel cell systems for commercial utilisation in motor vehicles in 1992. In consequence, Japanese (above all Toyota) and later American (GM and Ford) and since 2006 also Korean (Hyundai) manufacturers were spurred into action to discover advantages of this technology.

Since the advent of its industrial development in 1992, the evolution of hydrogen-based E-mobility using fuel cell engines has been full of optimism. The rapid breakthroughs in fuel cell engine technology development have been demonstrated in a collaborative study by the international automotive industry [EU Coalition Study 2010]. Initial announcements by car manufacturers herald the market launch of serial FCEVs in 2015. The hydrogen infrastructure agenda of industry and politics is currently preparing roadmaps for the establishment of an adequate infrastructure aiming for 400 hydrogen refuelling station in Germany by 2023.

### 3.3.2 Infrastructure and storage

In the context of an increasingly ambitious RE strategy, the electricity industry has been giving attention to the future necessity of storage options for substantial quantities of electric energy since 2008. Energy in storage serves to balance periods of low electricity production of fluctuating electricity from wind and photovoltaics [VDE 2008]. It became apparent that chemical energy storage is the sole option sufficient to supply the required large-scale energy storage potentials in Germany.

In representation of the automotive industry, GM/Opel was the first company to suggest the concept of a joint utilisation of a hydrogen fuel infrastructure by both the electricity and transport sector [GM 2010]. However, GM/Opel did not proceed to advance the concept in greater detail. Volkswagen also addressed the issue in a study based on realistic assumptions developing the idea of a joint hydrogen infrastructure utilisation across sectors, yet also

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3 The use of fuel cell engines for passenger cars was already explored by GM in the 1960ies with a delivery van. An overview of the evolution of fuel cell technologies for passenger cars may be found in [Brinkmann 2012].

4 The improvement is primarily found in the engine (performance density, system integration of all engine components with comparable volume and weight in reference to conventional engines) and the benefits to buyers (versatility through highly dynamic driving performance, mileage, load and refuelling time).
did not further pursue the approach [Volkswagen 2012]. The most important insight was the finding that cooperation of different energy sectors reduces infrastructure costs.

Parallel to these efforts and independently, the natural gas industry endeavoured to identify new end user markets due to declining demand for natural gas for heating and hot water supply in private households [BMWi 2013] and for electricity generation. One potential option identified was the support of the electricity sector through transport and storage of large quantities of chemical energy in the existing natural gas grid, including large-scale natural gas storage facilities. [ZWS 2009] and [IWES 2009] developed the required process technology and simultaneously managed to bridge the gap with the application of PtG in transport building on methanation of hydrogen with CO$_2$ using the synthetic methane being produced in CNG vehicles.
4 Specific energy use, environmental impacts and costs

The following chapter summarises technological and environmental baseline data for fuel infrastructure and vehicles. Based on these data, the (a) energy efficiency / energy use, (b) specific greenhouse gas emissions, (c) acidification potential and (d) specific costs per kilometre driven were calculated for relevant fuel supply and vehicle options. All calculations in this chapter are in reference to the time horizon 2030. This timeframe was chosen due to the fact that it represents the earliest wide introduction of PtG pathways into transport, i.e. the introduction of vehicles in numbers relevant for the market.

4.1 Energy chains

The comparison of different PtG chains for road transport purposes (passenger cars and 40 t HDVs) included several steps. Initially, relevant fuel supply chains composed of well-to-tank (fuel supply) and vehicle (passenger car and HDV) aspects were defined:

- Conventional best-practice reference pathways for internal combustion engine vehicles based on petrol or diesel (LDV: hybrid, HDV: Otto or diesel engine),
- Conventional reference pathway for fuel cell electric engines based on hydrogen from steam methane reforming,
- Natural gas (as CNG) in internal combustion engines (LDV: hybrid, HDV: petrol engine),
- PtG (synthetic methane) in internal combustion engines (LDV: hybrid, HDV: Otto engine), distinguishing the concepts (1) CO₂ from ambient air, (2) CO₂ from wood-fired CHP plant flue gas and (3) CO₂ from biogas upgrading, and
- PtG (hydrogen) in fuel cell electric engines.

The vehicle comparison in 2030 included the most relevant engine types, respectively. In principle, the selection and data followed the findings of the JRC/EUCAR/CONCAWE analyses and database [JEC 2013], as well as current assumptions from TREMOD. All data were either adopted from the Fuel Matrix under development in the context of the MFS or used to update the matrix in case of new data.

The PtG chains thus modelled were exclusively based on renewable energy.

The natural gas pathway for passenger cars and HDVs (CNG vehicles) and the hydrogen pathway from natural gas (FCEVs) were included for comparative assessment of PtG methane pathways. PtG pathways excluded CO₂ from fossil energy carriers and focussed on CO₂ from biogas upgrading, combustion of biomass (here: wood chips) and CO₂ from ambient air. These assumptions are considered appropriate for PtG scenarios with 100% renew-
able electricity. The use of fossil CO₂ sources would rely on a continued operation of fossil power plants, which is counterproductive to pursuing a growing renewable electricity supply.

For the hydrogen pathway from PtG, it was distinguished between centralised hydrogen supply and supply on-site at the refuelling station. Thus, the influence of a future hydrogen distribution infrastructure on costs and environmental impacts could be assessed in detail.

The energy chains investigated in this study are compiled in Figure 4.

![Energy chains](image)

**Figure 4:** Fuel supply pathways explored in this study

### 4.2 Vehicles

**Passenger cars (LDVs)**

The consumption levels of future passenger cars in 2030 used in the well-to-wheel analyses were adopted from [JEC 2013], [ICCT 2012] as well as derived from own modelling. The data for the New European Drive Cycle (NEDC) from [JEC 2013] were modified (+21%) following [ICCT 2012] to reflect additional consumption not factored into the model (e.g. air conditioning) and more dynamic driving. Moreover, hybrid plug-in vehicles with internal combustion engines will benefit more strongly from the NEDC compared to conventional vehicles with
internal combustion engines. According to [JEC 2013], hybrid consumption in 2020+ will be reduced by 35% (petrol) or 25% (diesel) in comparison with non-hybrid reference vehicles. The engine technology development potential was based on these assumptions.

Modelling efforts by IFEU with actual drive cycles reveal that such advantages in consumption appear realistic in inner-city settings. However, inner-city driving accounts for only about 30% of the average driving profile. In motorway driving, the consumption advantage is essentially compensated for by the additional vehicle weight. In consequence, the actual consumption increase for hybrid vehicles, adopted to adjust long-term assumptions published in [JEC 2013] for a vehicle in the year 2030, was approximately doubled in reference to non-hybrid vehicles (+42%). The actual consumption of petrol hybrid vehicles still holds a 23% advantage over non-hybrid reference vehicles. For diesel hybrid passenger cars, the savings in comparison with conventional cars amount to 13%.

CNG passenger cars equipped with internal combustion engines were also compared to those with hybrid engines to avoid discrepancies between the stages of technological evolution represented in the comparisons. In contrast to [JEC 2011], the recent [JEC 2013] no longer reports consumption data on CNG hybrid vehicles. In consequence, fuel consumption of CNG hybrid vehicles was adapted to petrol hybrid vehicles reflecting the ratio of consumption\(^5\).

**Heavy-duty vehicles (HDVs)**

The fuel consumption of a diesel-fuelled HDV with a gross vehicle weight of 40 t in 2030 was adopted from TREMOD, Version 5.3 (2025). The fuel consumption of the CNG HDV was derived from the ratio between the current consumption of a CNG HDV and a diesel HDV, multiplied by the expected fuel consumption of a diesel HDV in 2030.

Due to the scarcity of literature data, the extrapolation for fuel cell electric HDVs followed similar principles. A conservative consumption level of the current diesel vehicle was assumed to reflect the larger development potential of alternative engine technologies. Data assumed for fuel consumption and emissions of reference vehicles are reported in Table 1.

\(^5\) Consumption of CNG hybrid passenger car = (consumption of CNG car / consumption of petrol car) * consumption of petrol hybrid car
### Table 1: Fuel consumption and emissions of vehicles tank-to-wheel 2025-2030

<table>
<thead>
<tr>
<th></th>
<th>Consumption</th>
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<th>Exhaust emissions</th>
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<tr>
<td></td>
<td>MJ/km</td>
<td>CO₂ (g/km)</td>
<td>CH₄ (g/km)</td>
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<tr>
<td><strong>LDV (Hybrid)</strong></td>
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<tr>
<td>Petrol</td>
<td>1.326</td>
<td>97</td>
<td>0.006</td>
</tr>
<tr>
<td>Diesel</td>
<td>1.243</td>
<td>91</td>
<td>0.0090</td>
</tr>
<tr>
<td>CNG</td>
<td>1.351</td>
<td>74</td>
<td>0.0130</td>
</tr>
<tr>
<td>Fuel cell</td>
<td>0.652</td>
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<td>0</td>
</tr>
<tr>
<td><strong>HDV (40 t)</strong></td>
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</tr>
<tr>
<td>Diesel</td>
<td>9.78</td>
<td>717</td>
<td>0.0005</td>
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<tr>
<td>CNG</td>
<td>12.71</td>
<td>699</td>
<td>0.0007</td>
</tr>
<tr>
<td>Fuel cell</td>
<td>7.82</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

For passenger cars, the efficiency of the FCEV is approximately doubled in comparison with petrol and diesel-fuelled internal combustion engines. For HDVs with 40 t GVW, the fuel consumption of the FCEV is only about 20% lower than that of the diesel-fuelled internal combustion engine vehicle. Technological and operational advances have resulted in the very high energy conversion efficiency of modern HDV diesel engines as applied here.

In Table 1, the 30% difference of fuel consumption between CNG HDVs (2030) and comparable diesel HDVs is noticeable. The high consumption in CNG HDVs derives from the fact that future CNG HDVs will exclusively rely on Otto engines. Diesel engines operated in combination with CNG would fail to comply with methane emission targets and other restrictions (refer to parallel MFS study⁶ [LNG 2014]). However, the cycle efficiency of Otto engines is distinctly unfavourable.

#### 4.3 Results of the fuel chain comparison

##### 4.3.1 Energy use / energy efficiency

Figure 5 and Figure 6 illustrate the comparison of primary energy use for passenger car and HDV fuel supply chains analysed here in detail, distinguished into fossil and PtG energy pathways and including fossil and renewable energy sources.

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⁶Diesel-based CNG engines are operated with so-called dual-fuel technology. Diesel is added to CNG via pilot injection. German HDV manufacturers expect that these engines will in all likelihood fail to comply with the methane emission reduction targets stipulated in the EURO VI standard that came into effect in January 2014. Dual-fuel engines are no longer operable as dedicated diesel engines in secondary markets. Thus, the resale of used HDVs is not economically viable. These economic aspects may explain the hesitant attitude of HDV manufacturers towards this engine technology.
The distance-specific primary energy use of LDVs does not significantly differ for petrol, natural gas and diesel fuel. However, future CNG internal combustion engines in HDVs are expected to be Otto engines. In consequence, their primary energy use is almost 25% higher than that of current diesel-fuelled diesel engines.

Shares of renewable energies in the fossil-based energy chains (e.g. in the form of auxiliary energy) may be considered negligible.

![Figure 5](image)

**Figure 5:** Primary energy use of LDVs well-to-wheel, 2030 (for details see Appendix)
Figure 6: Primary energy use of HDVs well-to-wheel, 2030 (for details, see Appendix)

FCEVs fuelled with hydrogen from steam methane reforming reduce primary energy demand by approx. 25% in comparison with conventional cars operated with fossil fuels. The reason is the doubling in energy conversion efficiency apparent from the comparison of fuel cell engines with internal combustion engines.

Diesel engines in HDVs are primarily operated under nominal load with very high energy conversion efficiency. In consequence, fuel cell engines in HDVs are not associated with any advantages regarding primary energy use. In comparison with CNG-fuelled internal combustion engines, fuel cell engines may provide an energy conversion efficiency advantage of 10% due to the assumed operation of petrol-fuelled internal combustion engines.

As stipulated in the assumptions, PtG pathways are exclusively modelled with renewable electricity.

The comparison of methane and hydrogen-based PtG pathways reveals marked energy conversion efficiency advantages for fuel supply (additional methanation) and vehicle propulsion (fuel cells replacing internal combustion engines). Depending on the CO₂ source for methanation from hydrogen and CO₂, the energy use of LDVs may be two to three times higher for methane pathways compared with hydrogen pathways. For HDVs, the difference is limited to a factor 2 due to reasons explained above. Energy-intensive CO₂ supply from air is associated with the highest primary energy demands.
4.3.2 Greenhouse gas emissions

Grouped into fossil and PtG pathways and separated by process stages, Figure 7 and Figure 8 illustrate specific GHG emissions in g CO₂ equivalent per kilometre driven for LDVs and HDVs, respectively. Again, the fuel supply pathways selected were those introduced in Chapter 4.1.

Life cycle analyses involving transportation fuels frequently use the terms ‘Well-to-Tank’ (WtT) and ‘Tank-to-Wheel’ (WtW). For the holistic comparison of energy chains in transport, it is common to differentiate between two parts of the energy chain. The first stage characterises the energy chain from energy source (well) to fuel in the vehicle (tank) (well-to-tank), whereas the second stage considers the fuel in the tank to the vehicle wheel (tank-to-wheel), thus exclusively focusing on the vehicle. In the case that both parts of the energy chain are combined, the analysis is often labelled well-to-wheel, i.e. from primary energy used to transport service, the kilometre driven.

![Figure 7: Greenhouse gas emissions from LDVs well-to-wheel, 2030 (based on: renewable electricity, for details see Appendix)](Image)
Figure 8: Greenhouse gas emissions well-to-wheel HDVs, 2030 (based on: renewable electricity, for details see Appendix)

The analyses reveal that operation of passenger cars with CNG from natural gas is associated with 10-15% reductions of GHG emissions in comparison with petrol or diesel from crude oil. In contrast, specific CO\textsubscript{2} emissions of CNG HDVs (Otto engine) are slightly higher than those of diesel HDVs.

To prove one of the most important points in favour of fuel cell technology for road vehicles that might also be instrumental in promoting PtG pathways, the supply of LDVs and HDVs with hydrogen from steam methane reforming was included in the analysis. The results reveal that greenhouse gas emissions could be reduced by almost 25% if hydrogen from fossil natural gas via steam methane reforming was favoured over direct utilisation of natural gas in CNG cars. The high efficiency of the fuel cell engine is responsible for the GHG savings. Additional losses associated with steam methane reforming are thus overcompensated by highly efficient final energy use. For HDVs, the savings amount to a mere 5% due to the previously mentioned high efficiency of internal combustion diesel engines over long distances.

However, only the complete elimination of fossil primary energy sources reveals the enormous climate change mitigation potential of the PtG pathways explored here with respect to the transport sector. Apart from minimal CO\textsubscript{2} emissions from the supply of auxiliary energy, the CO\textsubscript{2} emissions of all explored fuel supply pathways are reduced to almost zero, independent of the PtG supply pathway, i.e. via hydrogen or synthetic methane.
The grey bar represents the range of GHG emissions for the operation of a petrol or diesel-fuelled passenger car.

Consumption after Chapter 4.2.

Figure 9: Greenhouse gas emissions well-to-wheel per km for LDVs in correlation with electricity mix or associated CO₂ intensity

Generally speaking, and based on the formal definition, the supply of gaseous energy carriers or fuels with PtG may utilise electricity of unspecified origin. In addition to the renewable electricity that our analyses were based on, nuclear or fossil electricity could be part of the electricity mix in principle. Many current analyses expect that to ensure profitability, electrolyser electricity input from renewable sources may have to be supplemented with inexpensive electricity, e.g. from the energy exchange EEX, for an extended transition period [HyUnder 2014]. The following circumstances are responsible:

- The capital costs for electrolysers are substantial. Thus, it is economically desirable to operate them to their maximum potential per annum.
- ‘Excess electricity’ in renewable energy plants that may not be utilised is expected to be available for no more than a few hundred hours per annum⁷. This is insufficient for the economically viable operation of electrolysers.
- In consequence, the selective purchase of ‘grey electricity’, i.e. energy exchange electricity from renewable, fossil and nuclear sources, was assumed, particularly at times

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⁷ The curtailment of renewable electricity volume in Germany (that could be integrated via PtG) does not exceed 0.1% of the German electricity consumption at present [BNA 2013].
of low electricity pricing. Periods with low energy exchange prices are likely to coincide
with high shares of RE electricity. Thus, the resulting fuel costs are decreased, and
electricity is utilised when overabundant (thus the discounted price) and likely derived
from renewable sources. In this scenario, economic advantages are combined with a
stabilising impact on the overall energy system.

An important point in favour of the introduction of PtG into transport is the reduction of
greenhouse gas emissions. The origin and verifiability of electricity used in PtG production
are pivotal in this context. Of particular importance is the development of a customised
methodology for the certification of renewable electricity in transport.

For demonstration purposes, the grey bar in Figure 9 allows the calculation of a CO₂ factor
for the utilisation of PtG fuels in passenger cars. This factor is derived from the specific
greenhouse gas emission of petrol/diesel dependent on the electricity mix (x-axis). Thus, it is
revealed that with both the current electricity mix and even the electricity mix expected for
2030, the GHG balance of synthetic methane compares unfavourably with that of petrol and
diesel vehicles. However, in light of the projected continued development of renewable ener-
gies and resulting changes to the electricity mix in the period to 2050 [DLR 2012], this situa-
tion will turn around after 2030. In consequence, the production of synthetic methane will
provide GHG advantages in reference to the kilometre driven. In the case of hydrogen, the
turnaround is expected already after 2020 due the higher overall energy conversion efficien-
cy along the entire fuel supply chain.

4.3.3 Acidification of soils and waters

The acidification potential (NOₓ, SO₂) was analysed to exemplify pollutant emissions from
fuel supply and use, and to ascertain that no detrimental environmental impacts from the
reduction of greenhouse gas emissions via PtG are overlooked. Acidification is associated
with a number of environmental impacts, e.g. damage to the ecology of vegetation and water
bodies.

Figure 10 and Figure 11 illustrate the acidification potential resulting from SO₂ and NOₓ emis-
sions. The results are reported identifying the individual process stage and presented sepa-
rately for the supply and utilisation of petrol and diesel from crude oil, CNG from natural gas,
CGH₂ from steam methane reforming, CNG from renewable electricity and CGH₂ from re-
newable electricity.
Figure 10: Acidification potential resulting from SO$_2$ and NO$_x$ emissions from LDVs well-to-wheel, 2030

Figure 11: Acidification potential resulting from SO$_2$ and NO$_x$ emissions from HDVs well-to-wheel, 2030
SO\textsubscript{2} and NO\textsubscript{x} emissions and the associated acidification potential are distinctly lower for CNG and CGH\textsubscript{2} from natural gas in comparison with petrol and diesel from crude oil. Acidification from hydrogen-derived renewable Power-to-Methane, via electrolysis and methanation with renewable electricity, arises mainly from vehicle NO\textsubscript{x} emissions during fuel combustion. FCEVs operated with hydrogen from renewable electricity distinguish themselves by very low acidification potential. Thus, PtG in transport makes a major contribution for substantial reductions of environmental impacts associated with NO\textsubscript{x} and SO\textsubscript{2}.

### 4.3.4 Specific costs per kilometre driven

The comparison of specific fuel production costs\textsuperscript{8} associated with the operation of passenger cars and HDVs with different technologies (in €/km) excluded vehicle costs. This omission was based on the assumption that costs for vehicles with alternative engines are unlikely to differ substantially from current engines in the medium-term. This is consistent with findings from the EU Coalition Study that allowed the international automotive industry to draw seminal conclusions for BEVs and FCEVs [EU Coalition 2010].

Figure 12 illustrates specific fuel production costs for passenger cars in €/km for the respective fuel and engine options. Figure 13 reports specific fuel production costs for HDVs, keeping all other assumptions constant.

The results of a sensitivity analysis on PtG costs depending on increasing petrol/diesel prices as a consequence of global scarcity of crude oil are included in Figure 12 and Figure 13 with an additional grey bar. This bar illustrates specific costs/km for an oil price range between 93 €/bbl after [IEA 2013, S. 491, ‘New Policies Scenario’] and 188 €/bbl after [German-Hy 2008] (upper limit). The average electricity price of 8.5 Cent/kWh was adopted from the Leitstudie [BMU 2012].

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\textsuperscript{8} Specific fuel production costs: Costs arising during the production of a fuel from a certain energy or energy mix along one or several conversion process chains in reference to kilometre driven.
Figure 12: Fuel production costs for LDVs well-to-wheel, 2030

Figure 13: Fuel production costs for HDVs well-to-wheel, 2030
The lower oil price threshold results in 70-100% increases in km-specific costs of FCEVs in comparison with conventional reference vehicles. However, in case the oil price more than doubles by 2030, costs per kilometre driven level out for FCEVs and petrol/diesel LDVs.

The costs of alternative HDV engines are higher than those of diesel-fuelled internal combustion engines in both price scenarios, although to a lesser extent in the case of operation with fuel cell and hydrogen. Again, the reason may be found in the very high energy conversion efficiency of HDV diesel engines. In consequence, the conversion efficiency difference between fuel cell electric and diesel engines for long-distance HDVs is reduced.

In the case of synthetic methane, equal costs with conventional fuels would not be achieved even with very high crude oil prices.

4.4 Hydrogen costs and competitive hydrogen pricing

The following chapter focuses on the comparison of hydrogen production costs with the market prices on the respective markets (fuel for mobility, industrial feedstock, reconversion for the electricity sector, utilisation/storage in natural gas grid by the natural gas industry) in 2030. Following the methodology of other studies [Stiller 2010], [Volkswagen 2012], both

- the costs for hydrogen supply via PtG and
- the expected market prices derived from comparison with the respective alternatives

were calculated based on the assumptions from the present study. The comparison considers energy equivalents, i.e. energy conversion efficiencies of engines or conversion pathways, of novel technologies and reference concepts (e.g. internal combustion engine vehicles in comparison with FCEVs). The following reference definitions were applied:

**Fuel for mobility:** The reference vehicle is a petrol/diesel-fuelled passenger car (C-segment e.g. VW Golf) with hybrid internal combustion engine. It is compared to a hydrogen-fuelled FCEV compact LDV of similar size (with assumptions on infrastructure costs including refuelling station and fuel taxation).

The focus of the analysis was the level that hydrogen production costs employing current production techniques should not exceed to compete economically. The analysis was based on the consumption data introduced above. The assumptions on hydrogen production, storage and distribution are detailed in Chapter 4.1 (Energy chains).

**Industrial feedstock:** The reference is the current hydrogen production technique from centralised methane steam reforming exclusive of distribution infrastructure. Instead, it is expected that the PtG plant is located on or in close proximity to industrial areas, e.g. oil refineries. Investment and operation costs are included in the calculations (natural gas supply, maintenance costs, costs for CO₂ emission certification).
Utilisation or storage in the natural gas grid by the natural gas industry (downstream): The reference is the natural gas price for customers inside the industry applying the assumptions of the present study (energetic coupling to the crude oil price: 80%; see Chapter 4.1 ‘Energy chains’).

Reconversion for the electricity sector: Here, competitive hydrogen production costs are based on the assumption that electricity produced in a natural gas power plant serves as a reference that is comparable to the technical data for a gas turbine power plant for the re-conversion of hydrogen. The natural gas price is defined according to the assumption for the gas industry.

Table 2 summarises all assumptions underlying the calculation of competitive hydrogen production costs for the year 2030. Petrol and diesel prices were based on assumptions outlined in Chapter 4.1.

Table 2: Competitive hydrogen production costs for different markets

<table>
<thead>
<tr>
<th>Market</th>
<th>Reference</th>
<th>Key assumptions (2030)</th>
<th>Max. H₂ costs permitted [€/kg₇₂]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel for mobility</td>
<td>Diesel/ petrol in internal combustion engine LDVs</td>
<td>Petrol price w/o tax: 0.65-1.22 €/l&lt;br&gt;Diesel price w/o tax: 0.74-1.39 €/l&lt;br&gt;Diesel: 3.46 l/100km&lt;br&gt;Petrol: 4.12 l/100km&lt;br&gt;H₂: 0.54 kg/100km (fuel cell)</td>
<td>4.7 - 9.3</td>
</tr>
<tr>
<td>Industrial feedstock</td>
<td>Natural gas for steam reforming in refinery</td>
<td>Natural gas price: 47-94 €/MWh&lt;br&gt;H₂ production capacity: 844 MW&lt;br&gt;Energy conversion efficiency: 76%.&lt;br&gt;Operational lifespan: 25 years&lt;br&gt;Interest: 8%&lt;br&gt;Annual full load equivalent operation hours: 7000 h&lt;br&gt;Investment: 262 M€&lt;br&gt;CO₂ emissions certificates: 29.13 €/t CO₂</td>
<td>2.5 - 4.5</td>
</tr>
<tr>
<td>Utilisation/storage in natural gas industry</td>
<td>Mean natural gas price</td>
<td>Natural gas price: 47-94 €/MWh</td>
<td>1.6 - 3.1</td>
</tr>
<tr>
<td>Reconversion for electricity sector</td>
<td>Mean electricity price from natural gas CCGT plant</td>
<td>Assumption: electricity produced from natural gas</td>
<td>1.6 – 3.1</td>
</tr>
</tbody>
</table>
Based on the assumptions defined in Chapter 4.1 (Energy chains), the production price for hydrogen from electrolysis with renewable electricity and bulk storage in a typical salt cavern amounts to 7.3 € per kg hydrogen (excl. H₂ pipeline grid and refuelling station)\(^9\).

These costs were compared with the hydrogen production costs based on energy exchange prices (grey electricity) reported in [Stiller 2010]. According to several analyses, hydrogen production costs via electrolysis modelled in wind energy-hydrogen scenarios (incl. dynamic electrolysis, bulk storage in a typical salt cavern and electricity supply from the energy exchange\(^10\) currently amount to approx. 4.5 to 6.5 €/kg (e.g. [Stiller 2010]). If electricity for electrolysis was available at 0 €/kWh, the resulting hydrogen fuel would be priced between 2.2 and 3.6 €/kg.

Hydrogen utilisation in industry, natural gas industry or in the electricity sector is exempt from costs for transport, distribution and fees due to the close spatial proximity of production plants to storage facilities. However, for the supply of road transport, these factors need to be considered. In the case that electrolysis is carried out on-site at the refuelling station, hydrogen transport is not applicable. Under consideration of costs for refuelling stations and assuming centralised electrolysis with the associated requirement for hydrogen transport pipelines, the hydrogen price at the fuel pump amounts to about 9.6 €/kg (before tax). This calculation is based on an annual operation time of approx. 4000 hours (with electrolyser costs of approx. 700 €/kW\(_{el}\)).

For the year 2030, Figure 14 reveals a potentially profitable implementation of hydrogen in the transport sector given the assumptions of the present study, even in case of hydrogen fuel taxation. However, the current assumptions discourage applications for the industry, reconversion or utilisation in the natural gas grid due to a lack of economic viability. In these cases, the production costs would be distinctly higher than expected market returns.

The present analysis does not consider socio-economic effects related to positive side benefits for the electrical energy system associated with storage. Among those are the avoidance of grid extension measures or the balancing of fluctuating production that would otherwise

\(^9\) The analysis is designed to provide an initial appraisal of the gap between hydrogen production costs and respective expected market returns. Inaccuracies may arise from the fact that data on the reference concepts, e.g. petrol or diesel fuel, include price margins, whereas the hydrogen production costs calculated here do not.

\(^10\) Dynamic electrolysis operation makes use of the lowest prices for electricity traded on the energy exchange. Studies to date have assumed a correlation between low electricity prices and high share of renewable electricity on the market, particularly in Northern Germany. It is debatable whether this assumed correlation is going to hold in the medium to long-term. The extent to which renewable Power-to-Hydrogen is CO\(_2\) neutral remains to be determined.
require regulatory action for the grid. However, these effects remain irrelevant for business economics until appropriate regulatory measures associate them with financial benefits.

In consequence, the implementation of PtG, or the utilisation of the resulting hydrogen as reported in country-specific case studies in the European HyUnder Project [HyUnder 2014], is associated with an obvious mismatch concerning its economic benefits for the energy system:

- on the one hand, there is common consensus on the fact that only chemical energy storage (hydrogen or methane) is associated with sufficient potential to supply the required energy storage volumes with high shares of renewable energies in the grid (> 50%) in the long-term, whereas
- on the other hand, all available models predict an economically viable implementation of hydrogen as fuel only in transport. For all other sectors (electricity, gas, industry, methane as fuel), PtG remains uneconomical in the long-term.

In consequence, the transport sector is in a pivotal position as a forerunner and initiator for hydrogen PtG pathways.

![Figure 14](image)

**Figure 14:** Hydrogen production costs for 2030 and cost ranges for competing solutions by market sector from Table 2

### 4.5 Profitability of Power-to-Gas

As long as the kWh rate for gas remains distinctly lower than that for electricity, methane from PtG will only be able to compete in the case of high fees for CO₂ emissions certificates. In turn, the loss-making production of methane from expensive renewable electricity will inev-
itably increase costs in comparison with natural gas. The advantage of synthetic methane lies in its inherent potential for CO$_2$ neutral fuel supply. However, as long as there is no financial reward, there is no market for any of the applications introduced here.

Similar principles apply to the transport sector. The profitability of methane pathways from PtG is lower compared with hydrogen from PtG due to distinct losses in energy efficiency along the entire supply chain for RE electricity to the kilometre driven (methanation, CNG instead of FCEVs). Thus, an elaborate analysis was omitted from the present study for reasons detailed above.

Nonetheless, the low profitability of methane pathways may be partly offset by the fact that the development of a dedicated distribution infrastructure is not required. In the case of methane production via PtG, the existing natural gas infrastructure may be utilised without restrictions. For hydrogen, this infrastructure would have to be raised from the ground up. Profitability analyses would be necessary, yet these are complex due to unpredictable market trajectories. Additional detailed analyses on both renewable hydrogen and renewable methane-based PtG areas of application are required for market preparation purposes. These should include socio-economic aspects, i.e. consideration of additional hydrogen infrastructure costs and expected advantages for all consumer sectors.

The partners of the industrial consortium H$_2$ Mobility play a vital role in the establishment of collaborations with other energy sectors aiming to explore economic synergies. Thus, allocation of costs for methane and hydrogen infrastructure may allow utilisation in the respective markets.

4.6 Technical potential of CO$_2$ supply from renewable sources

Methanation of hydrogen requires CO$_2$ as a feedstock that may be obtained from a number of sources. In addition to fossil sources, e.g. flue gas from fossil power plants, CO$_2$ from biogenic sources, other industrial processes and from ambient air may be utilised.

A long-term sustainable production of Power-to-Methane dictates the utilisation from equally sustainable sources. The debate on the term ‘sustainable CO$_2$’ is still under way. A broad definition identifies three categories of CO$_2$ sources which differ in sustainability:

- Fully sustainable: biogenic CO$_2$ (e.g. biogas upgrading, flue gas from wood combustion and wood CHP plants) or CO$_2$ from ambient air,
- Partly sustainable: industrial processes that may be substituted in part (e.g. concrete production) and
- Non-sustainable: fossil-based industrial processes (e.g. coal-fired power plants, steel works).
The following subchapter explores the availability of CO$_2$ from the first two categories. The industrial processes included represent those that may be expected to reliably supply CO$_2$ in the long-term, i.e. in case of distinct shortages or without the availability of fossil energy.

All quantities discussed in the following are simplifications presented for overall guidance. Exact calculation of technical CO$_2$ potentials and the determination of technical and economic CO$_2$ potentials of biogenic origin would require elaborate additional analyses. Factors to be investigated include, among others, distribution of feedstocks, feedstock properties, operation facility size and categories as well as their specific features (e.g. energy conversion efficiency). Moreover, an assessment of the technological and economic exploitation of potential quantities is required to identify the available and realisable potential.

### 4.6.1 Biogenic CO$_2$ potential

Under consideration of spatial and temporal availability, CO$_2$ from processing and combustion of biomass represents one option$^{11}$. Therefore, both the technical potentials of CO$_2$ from biogas upgrading to biomethane and from the combustion of biomass are examined.

**CO$_2$ from biogas**

The DBZF and their collaboration partners submit an annual report to the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety reporting on the development and quantities of electricity supply from biomass. In addition to a number of further data sources, the present study analysed the results of the annual operator survey. According to this survey, on 31.12.2012, about 120 facilities for the production of biomethane with a feed-in capacity of approx. 72,000 m$^3$/h were in operation [DBFZ et al. 2013]. Crude biogas contains between 25-55% CO$_2$ (depending on feedstock, among other things), yet a maximum of 6% may remain in biomethane [DVGW 2004], [DVGW 2008]. Assuming an annual biomethane production of 560 million Nm$^3$/a, the arising CO$_2$ volume totals at approx. 330 million Nm$^3$/a$^{12}$. This would be sufficient for the production of 11 PJ of synthetic methane, which in turn would supply fuel for the operation of about 600,000 CNG hybrid vehicles (consumption: 1.35 MJ/km; mileage: 14,000 km/a).

The conversion of biogas plants with prior on-site electricity generation and their extension to include methanation facilities (and feed-in) is more elaborate than the upgrading of opera-

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$^{11}$ Spatial aspect: locations of biogas facilities and PtG plants distributed across Germany should be matched. Temporal aspect: operation profiles should be synchronised.

$^{12}$ Assumptions: 8000 full load hours per annum, extraction of 30 vol.% CO$_2$ from crude biogas
tions that are already fitted with biogas upgrading facilities for the feed-in of methane into the natural gas grid\textsuperscript{13}. The conversion of biogas plants should therefore not be considered below outputs of $< 1 \text{ MW}_{\text{el}}$ [Stockel 2013]. Independent of individual local conditions, the maximum theoretic potential for CO$_2$ from biogas is not expected to exceed approx. 625 million Nm$^3$/a (see Table 3). This would be sufficient for the production of about 22 PJ synthetic methane fuelling about 1.2 million CNG hybrid passenger cars. The technical or economic potential is distinctly lower (e.g. no conversion of plant utilising heat).

### Table 3: Estimate of theoretical CO$_2$ potentials from biogas in Germany based on existing stock in 2012

<table>
<thead>
<tr>
<th>Plant size</th>
<th>Biomethane</th>
<th>Biogas (optional)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant size</td>
<td>&lt; 350 Nm$^3$/h</td>
<td>350-700 Nm$^3$/h</td>
</tr>
<tr>
<td>Number of plants</td>
<td>24</td>
<td>83</td>
</tr>
<tr>
<td>Total capacity</td>
<td>ca. 71,700 Nm$^3$/h CH$_4$</td>
<td>600 MW$_{\text{el}}$</td>
</tr>
<tr>
<td>CO$_2$ potential</td>
<td>ca. 330 million Nm$^3$/a$^{12}$</td>
<td>ca. 625 million Nm$^3$/a$^{14}$</td>
</tr>
</tbody>
</table>

Number of plants, plant size and capacity after [DBFZ et al. 2013]

Figure 15 reveals an aggregation in spatial arrangement of facilities for production and feed-in of biomethane primarily in Eastern Germany. In analogy, the average installed output [kW$_{\text{el}}$] of biogas plants is unusually high in the eastern German Federal States and in Lower Saxony [DBFZ et al. 2013].

\textsuperscript{13} The revision of the German Renewable Energies Act in preparation does not apply due to the fact that our analysis focused on existing plants only. Furthermore, it was expected that legislation will continue to provide incentives for the production of electricity from biogas in the future, particularly in combination with (bio) gas storage to maintain greater flexibility for electricity feed-in. Thus, it is expected that existing operations will continue to be used for electricity production in the future.

\textsuperscript{14} Assumptions: 7650 full load hours per annum [DBFZ et al. 2013], \(\bar{\Omega}\) energy conversion efficiency 33 \%, biogas: 5.5 kWh/m$^3$ with 55 \% CH$_4$, extraction of 30 vol.% CO$_2$ from crude biogas.
Figure 15: Sites of biogas upgrading and feed-in facilities in operation in Germany including upgrading capacity (Nm³/biomethane/h) [DBFZ et al. 2013]

The CO₂ potentials from biogas facilities reported in Table 3 suffice for the annual production of approx. 955 million Nm³ or about 9.5 TWh (34 PJ) synthetic methane. This is equal to about 1.6% of the current fuel consumption in Germany (excluding aviation).

CO₂ from biomass CHP plants

In Germany, facilities for the combustion of solid biomass are compensated according to the German Renewable Energies Act. At the end of 2012, about 540 biomass CHP plants (excluding co-incineration plants) were operated with an electrical output of about 1560 MW. Of the total, about 200 plants had an installed electric capacity of > 1 MW (96% of total output). CO₂ extraction from arising flue gas would yield a theoretic CO₂ potential total of approx. 8 billion Nm³ or 7.7 billion Nm³ (see Table 4).
Table 4: Estimate of theoretical CO\textsubscript{2} potentials from biomass CHP plants based on the existing stock in 2012

<table>
<thead>
<tr>
<th>CHP plants\textsuperscript{15} in the Renewable Energies Act</th>
<th>Fuel</th>
<th>Fuel volume</th>
<th>CO\textsubscript{2} potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Paper and pulp industry, excluded from the Renewable Energies Act</td>
<td>wood\textsuperscript{16}</td>
<td>8.7 million t\textsubscript{st}</td>
<td>ca. 8 billion Nm\textsuperscript{3} \textsuperscript{17}</td>
</tr>
<tr>
<td>Electricity production plants</td>
<td>liquor\textsuperscript{18}</td>
<td>21.2 PJ (wood eq. \textasciitilde 1.2 million t\textsubscript{st})</td>
<td>\textsuperscript{19}</td>
</tr>
<tr>
<td>Biogenic household waste</td>
<td>biogenic household waste</td>
<td>87.7 PJ\textsuperscript{20}</td>
<td>\textsuperscript{19}</td>
</tr>
</tbody>
</table>

Fuel volume after [DBFZ et al. 2013]

The regional distribution of solid biomass CHP plants is characterised by a distinct north-south divide (see Figure 16). The total installed plant capacity is greatest in the German Federal States of Bavaria (approx. 235 MW\textsubscript{el}), North Rhine-Westphalia (approx. 215 MW\textsubscript{el}) and Baden-Württemberg (approx. 170 MW\textsubscript{el}).

\textsuperscript{15} Incl. wood gasification plants and CHP plants of the paper and pulp industry usually compensated under the Renewable Energies Act

\textsuperscript{16} 56% scrap wood, 27% residual wood from forestry and landscaping, short rotation coppice, 17% scrap wood from wood, paper and pulp industries (industrial waste wood, bark, lye)

\textsuperscript{17} Assumptions: carbon content scrap wood 50 weight.-% in reference to dry weight, 99% conversion of carbon into CO\textsubscript{2}, 1% carbon loss via ash residues not available as CO\textsubscript{2}

\textsuperscript{18} Mostly co-incineration, i.e. combined use of fossil fuels

\textsuperscript{19} For the quantification of the CO\textsubscript{2} potential, reliable data on the elementary composition are required.

\textsuperscript{20} Deviation in reference year: 2011
Figure 16: Regional distribution of solid biomass CHP plants and wood gas generators by postal area code in Germany [DBFZ et al. 2013]

The 7.7 billion Nm³ CO₂ from CHP plants with an electric output exceeding 1 MW may be converted into approx. 7.7 billion Nm³ or about 77 TWh (276 PJ) synthetic methane per annum. This is equal to about 12.9% of the current fuel consumption in Germany (excluding aviation) and suffices for the operation of 14 million CNG hybrid passenger cars.

4.6.2 CO₂ from industrial processes

There is debate on whether CO₂ from industrial processes may be used for methanation. At present, CO₂ from industrial processes commonly arises from the combustion of fossil fuels. However, this source was deliberately excluded from this study. The intention is an overall reduction of CO₂ emissions in Germany instead of redistribution between the sectors. In consequence, the potential assessment included only CO₂ emissions unavoidable for maintenance of constant production output.

CO₂ may be supplied from industrial processes including concrete and steel industries. The quantities of CO₂ from industrial processes and potentials for their reduction were derived from [Herrmann et. al. 2012].
Table 5 illustrates the CO$_2$ potential from industrial processes before and after exploitation of potentials for the reduction of CO$_2$ emissions from fossil fuels. CO$_2$ from ammonia production (7.4 million t in 2008) was excluded due to the fact that the required hydrogen could be produced from renewable sources in principle.

**Table 5: CO$_2$ from industrial processes (million t/a)**

<table>
<thead>
<tr>
<th>Process</th>
<th>2008</th>
<th>Process related*</th>
<th>Top gas recycling in blast furnace process</th>
<th>Iron and steel via direct reduction with renewable hydrogen, inert anodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concrete production</td>
<td>21.0</td>
<td>13</td>
<td>13.7</td>
<td>13.7</td>
</tr>
<tr>
<td>Lime burning</td>
<td>7.5</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
</tr>
<tr>
<td>Iron and steel</td>
<td>52.3</td>
<td>52.3</td>
<td>34.0 (-35%)</td>
<td>0</td>
</tr>
<tr>
<td>Aluminium</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>81.6</td>
<td>72.8</td>
<td>54.5</td>
<td>19.7</td>
</tr>
</tbody>
</table>

* Excluding combustion of fossil fuel to cover the energy demand of the plant.

Under the assumption that future iron and steel production via direct reduction, carried out with renewable hydrogen and aluminium production, switches to inert anodes, 20 million t of CO$_2$ emissions per annum (approx. 10 billion Nm$^3$/a) remain. Thus, 99 TWh of synthetic methane could be produced annually, which equals about 16.6% of overall fuel consumption in Germany (excluding aviation). The result is based on the assumption that the output of concrete, lime, iron, steel and aluminium will remain constant in reference to 2008.

**4.6.3 Total CO$_2$ potentials**

Table 6 summarises CO$_2$ potentials and resulting potentials for the production of synthetic methane.

**Table 6: CO$_2$ potentials and resulting potentials for synthetic methane production in Germany**

<table>
<thead>
<tr>
<th>CO$_2$ potential</th>
<th>Unit</th>
<th>Biogas upgrading</th>
<th>Biomass CHP plant</th>
<th>Industrial processes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Million Nm$^3$/a</td>
<td>0.955</td>
<td>7.7</td>
<td>10.0</td>
</tr>
<tr>
<td>Methane potential</td>
<td>Million Nm$^3$/a</td>
<td>0.955</td>
<td>7.7</td>
<td>10.0</td>
</tr>
<tr>
<td></td>
<td>TWh/a</td>
<td>9.5</td>
<td>76.6</td>
<td>99.5</td>
</tr>
<tr>
<td></td>
<td>PJ/a</td>
<td>34</td>
<td>276</td>
<td>358</td>
</tr>
<tr>
<td>Total methane potential</td>
<td>PJ/a</td>
<td></td>
<td></td>
<td>667</td>
</tr>
</tbody>
</table>

In sum, CO$_2$ from biogas upgrading, flue gas from biomass CHP plants and from industrial processes amounts to about 186 TWh (668 PJ) synthetic methane per annum. This is equal to 31% of the current fuel consumption in Germany (excluding aviation) and allows for the operation of approx. 35 million CNG hybrid passenger cars.
5 Scenarios for the utilisation of PtG in transport

5.1 Background

The analyses in the preceding chapters illustrate that PtG theoretically presents a renewable energy alternative, e.g. by means of fuel cells or CNG/LNG internal combustion engines, for those parts of the transport sector where direct utilisation of electricity or operation with batteries is not an (economic) option. Thus, substantial GHG reductions may be achieved.

Three scenarios are chosen to explore the extent of PtG application (hydrogen, methane) in 2050 required to achieve substantial reductions of GHG emissions from road transport and inland navigation of around 80% in reference to 1990. Moreover, the required quantities of electricity for the PtG pathway are calculated. Based on the results of the analysis, opportunities and challenges in the energy and transport sectors associated with transport energy supply from PtG are discussed.

For the scenarios, the time horizon 2050 was adopted due to the fact that the following conditions have to be established for a significant share of PtG fuels in transport:

- Commercial supply of PtG requires substantial technical development (particularly with respect to costs and operation characteristics of electrolysers).
- Vehicle technology is not yet available for all vehicle types (especially in the HDV sector) and currently not competitively priced.
- Even after a successful market launch of the respective vehicles, it will take some time for them to contribute a substantial share to the total vehicle stock.
- Economically attractive supply of renewable electricity outside peak times is a prerequisite for the economic operation of PtG plants.

Due to these reasons, it is currently not realistic to assume that PtG fuels will be able to markedly contribute to the aims of the Mobility and Fuels Strategy by the year 2030. In consequence, the following chapter focuses on scenarios for the year 2050.
5.2 Parameters and assumptions

5.2.1 Transport parameters

The scenarios focus exclusively on road transport and inland navigation. Air transport is excluded due to the fact that it is expected to continue to rely on liquid fuels for the time being. In consequence, power-to-liquid (PtL) fuels may be an alternative; however, these are not included in the scope of the present study. Rail transport in Germany has generally been switched to operation with electricity already. In consequence, there is limited potential for the application of PtG, and rail transport was thus omitted here. GHG emissions considered include the entire production and use chains of the energy carriers, respectively.

The impacts of the application of PtG (methane, hydrogen) in road transport and inland navigation on GHG emissions, electricity consumption and final consumption of energy are calculated in three scenarios, see Table 7.

The baseline scenario assumes a fleet development trajectory based on the CNG vehicle development that represents a prerequisite for extended renewable Power-to-Methane utilisation. Scenario 2 is derived from the baseline scenario and anticipates CNG vehicles to be operated exclusively with renewable methane. In scenario 3, these vehicles are in part substituted by hydrogen FCEVs. Comparison of the results of the individual scenarios illustrates the impacts of extended application renewable Power-to-Hydrogen and renewable Power-to-Methane on energy consumption and GHG emissions in road transport and inland navigation. All scenarios are based on detailed modelling input data on the vehicle fleet, vehicle mileage and PtG production. Thus, a valid assessment of the associated electricity consumption is ensured.

21 Previous analyses and trials by Airbus, Dornier and Tupolew among others included liquid hydrogen (LH$_2$) as an alternative fuel for future air transport. However, this option is currently not widely considered.

22 Analysis of the switch from diesel or petrol fuels or engines is not subject of this study.
Table 7: Assumptions on fleet structure and energy carriers utilised

<table>
<thead>
<tr>
<th>Scenario 1: ‘CNG / LNG without PtCH$_4$’ (baseline scenario)</th>
<th>The focus in this scenario is on efficiency improvements for conventional internal combustion engines. From 2030, natural gas (blended with 10% biomethane) will be increasingly utilised as fuel, particularly in HDVs and inland waterway vessels. Thus, extensive penetration of the existing fleet with CNG/LNG vehicles is possible by 2050. The vehicle stock for battery electric vehicles reaches the 3 million mark in 2030 with subsequent stagnation of new registrations.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 2: ‘CNG / LNG with PtCH$_4$’</td>
<td>In contrast to scenario 1, here natural gas is successively replaced by renewable Power-to-Methane by 2050. In addition, plug-in hybrid passenger cars completely switch to CNG propulsion by 2050 (so that they also may be operated with renewable Power-to-Methane). Thus, this scenario illustrates the influence of the introduction of PtG technology in contrast to scenario 1 while other general assumptions remain largely constant.</td>
</tr>
<tr>
<td>Scenario 3: ‘RE PtCH$_4$ + FCEVs’</td>
<td>Similar to the previous scenarios, by 2030 CNG/LNG engines have become established outside a niche market. However, electric engines are also distinctly on the rise. It is expected that FCEVs will be competitive by 2030, assuming establishment of the corresponding hydrogen infrastructure with adequate coverage. Thus, particularly the percentage of FCEVs is expected to increase. Simultaneously, battery electric vehicles register substantially increased market shares, partly due to technological synergies with the development of FCEVs. Methane and hydrogen are generated from renewable electricity.</td>
</tr>
</tbody>
</table>

The mileage development trajectory in the scenarios was adopted from the TREMOD base scenario [Knörr 2012], which in turn is based on the traffic forecast for 2025 [Intraplan 2007]. The TREMOD base scenario assumes mileage increases of 13% in passenger transport and 49% in freight transport (in reference to 2010). The trajectory to 2050 for freight transport was adopted from [ProgTrans 2007] which corresponds to a mileage increase of 84% in comparison with 2010. Due to the trend to larger vehicles in road freight transport, the assumed growth in transport performance (in tkm) is even higher with +130%. In passenger transport, mileage is expected to remain constant after 2030 due to the expected decline in population. Transport performance of inland waterway vessels after [ProgTrans 2007] is assumed to increase by 60% in comparison with 2010.

The assumptions regarding the shares of the respective energy carriers on mileage and transport performance as well as the CNG and PtG percentages may be found in the following tables. Assumptions on vehicle technology are briefly illustrated in Appendix II and are identical with those applied in the scenarios ‘internal combustion engine’ and ‘fuel cell’, respectively, in the MFS short study ‘Renewable Energies in Transport’. 

Page 59 of 137
Table 8: Energy carrier shares of mileage (passenger cars) or transport performances (HDVs and inland vessels) in the scenarios

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1: ‘CNG / LNG without RE PtCH₄’</th>
<th>Scenario 2: ‘CNG / LNG with RE PtCH₄’</th>
<th>Scenario 3: ‘RE PtCH₄ + fuel cell vehicles’</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2050</td>
<td>2050</td>
<td>2050</td>
</tr>
<tr>
<td>Car Petrol/diesel</td>
<td>46.7%</td>
<td>43.3%</td>
<td>27.4%</td>
</tr>
<tr>
<td>CNG</td>
<td>28.8%</td>
<td>32.1%</td>
<td>10.0%</td>
</tr>
<tr>
<td>H₂ in fuel cell</td>
<td>5.7%</td>
<td>5.7%</td>
<td>35.9%</td>
</tr>
<tr>
<td>Electricity from grid</td>
<td>18.9%</td>
<td>18.9%</td>
<td>26.7%</td>
</tr>
<tr>
<td>HDV²</td>
<td>Diesel</td>
<td>12%</td>
<td>12%</td>
</tr>
<tr>
<td></td>
<td>CNG / LNG</td>
<td>80%</td>
<td>80%</td>
</tr>
<tr>
<td></td>
<td>H₂ in fuel cell</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>Electricity from grid</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Inland vessel</td>
<td>Diesel</td>
<td>50%</td>
<td>50%</td>
</tr>
<tr>
<td></td>
<td>LNG</td>
<td>50%</td>
<td>50%</td>
</tr>
</tbody>
</table>

Table 9: PtG share in the scenarios

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1: ‘without RE PtCH₄’</th>
<th>Scenario 2 + 3: ‘with RE PtCH₄’</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2050</td>
<td>2050</td>
</tr>
<tr>
<td>Share RE PtCH₄ of total H₂</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Share RE PtCH₄ of total CNG/LNG</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

5.2.2 PtG processes and electricity supply

Hydrogen production is assumed to be carried out with 100% electrolysis in all scenarios. Additional pathways like steam methane reforming or coal gasification do not qualify for the purpose of substantial GHG reductions and are thus excluded. Surplus ‘waste hydrogen’ from the industry does not arise in sufficient quantities to be relevant in the long-term. It may

²³ The proportional transport performances in the HDV segments N1, N2 and N3 were included in the scenario with separate assumptions; these were aggregated in this table for simplification purposes. Detailed information on the assumptions may be found in the MFS study ‘Renewable energies in transport’.
be considered for the transition period but the future mass market renders this source negligible.

Electricity supply for battery-powered or electric vehicles is modelled assuming the electricity mix in 2050 after the Leitstudie 2011 [DLR 2012]. Electricity supply for PtG (hydrogen, methane) is assumed 100% renewable in the scenarios. In addition, a sensitivity analysis explores changes in GHG emission if the 100% renewable energy supply for PtG is substituted by the electricity mix in 2050.

In the PtG scenarios (scenarios 2 and 3), a distinct increase in energy efficiency is assumed for all PtG processes between the years 2030 and 2050 (assumptions for 2030 were made in Chapter 4.2). This is due to the fact that commercial PtG production is expected to benefit from major technical innovations. Following [DLR 2012], the total energy conversion efficiency in reference to the lower heating value for H₂ electrolysis in 2050 is assumed to amount to 76%, whereas the total energy conversion efficiency for conversion of electricity into methane gas is expected to be 61%.

5.3 Results of the scenario calculations

5.3.1 Final energy demand

Despite the increase in transport performance and volume of traffic in all scenarios, the final energy demand in the sectors under investigation decreases due to efficiency improvements. In scenario 1, the energy demand by 2050 is reduced by 9% in reference to 2005. Scenario 2 explores substitution of fossil natural gas with renewable Power-to-Methane, which has no further effect on final energy demand. Only the introduction of larger quantities of FCEVs and BEVs with increased final energy efficiency results in additional energy demand reductions of 24%. Thus, in this scenario (3) a reduction of 33% is achieved in reference to 2005. The target stipulated by the German Federal Government, i.e. a 40% reduction of final energy consumption in transport by 2050 in reference to 2005, is attainable only with a distinct transition towards electric-powered vehicles. Detailed consideration of the data on hand shows that the final energy consumption of passenger transport in scenario 3 is substantially decreased (by 57% in comparison with 2010). However, increased engine efficiency in freight transport is unlikely to balance the expected increase in transport performance volume. In consequence, the final energy consumption in road freight transport is estimated to increase by 28%. Please note that introduction of PtG fuels would partly shift energy consumption to the fuel supply stage (H₂ or methane).
Figure 17: Final energy consumption in road transport and inland navigation

5.3.2 Electricity demand

Widespread introduction of PtG would essentially shift a major part of current energy demand for fossil fuels towards the electricity sector. The utilisation of PtG (methane and hydrogen) and BEVs would thus cause a considerable rise in the electricity demand of the transport sector. In scenario 2, the production of energy carriers utilised in transport (road transport/inland navigation) requires 614 TWh of electricity. In this case, the electricity demand of the transport sector (excluding the sectors air/railway transport and maritime navigation) would exceed demands of all other sectors combined (industry, private households, trade, commerce and service sectors). In scenario 3, the energy demand is considerably lower due to efficient fuel cells and BEVs; in consequence the electricity demand amounts to only 447 TWh assuming constant transport performance.
The sustainable potential of renewable electricity generation in Germany (under consideration of economic, technical and ecological constraints) available for all sectors amounts to the conservative estimate of 1000 TWh per annum (see MFS study ‘Renewable energies in transport’). This quantity would be slightly exceeded in scenario 2. In the case that additional transport sectors (e.g. PtG-fuelled air transport) are included in the supply with renewable energy, additional sources are required. For instance, the import of RE electricity or RE fuels may be an option. However, this approach is associated with both technical challenges and major strategic implications which should be given due consideration early on in the process. A higher share of battery electric engines and fuel cells (scenario 3) could potentially alleviate the situation.

Moreover, scenario 2 would require the establishment of a PtG capacity of approx. 150 GW electrolysis output (under assumption of 4000 peak load hours per annum). This would be associated with substantial financial investment. Investment costs would again be distinctly lower in scenario 3, particularly in view of the fact that the required plant capacity for methanation would also be much lower.
5.3.3 GHG emissions

In addition to consumption, GHG emissions from road transport and inland navigation today are primarily related to the carbon content of the fossil energy carriers diesel and petrol. In contrast, in the explored scenarios the efficiency of energy production (e.g. electrolysis)\textsuperscript{24} and the electricity mix play the most prominent role.

Despite a substantial energy efficiency increase in scenario 1, particularly for cars with internal combustion engines, the reduction of GHG emissions between 2010 and 2050 will not exceed 24% without the application of renewable energy carriers\textsuperscript{25}. Reasons include the limited CO\textsubscript{2} reduction potential associated with the utilisation of fossil CNG/LNG in the HDV sector and the expected increase in transport performance. HDV emissions in this scenario are projected to rise by 43% between 2010 and 2050. This increase nearly offsets the considerable reductions achieved in the passenger car sector (-53%) in the same period of time.

The application of PtG technologies to generate methane from entirely renewable electricity (scenario 2) is associated with GHG emissions reductions of 73% in reference to 1990. If the electricity demand is further decreased through the increasing utilisation of BEVs and FCEVs (scenario 3), application of 100% renewable energies further reduces GHG emissions to -82% in reference to 1990.

Simulation modelling of the electricity market shows that under certain circumstances, the use of PtG system for interim storage in energy systems with high RE shares may lead to an increased utilisation of fossil base load power plants with associated increased GHG emissions [VDE 2012, Pehnt 2010]\textsuperscript{26}. Hence, a sensitivity analysis explored resulting effects on reductions in the transport sector for the case that PtG was generated employing the projected electricity mix in 2050. Emissions factors (incl. fuel chains well-to-tank) were calculated based on the scenario A of the BMU- Leitstudie 2011 that assumes an RE share of 85% in 2050.

\textsuperscript{24} For simplification purposes, calculations assumed the CO\textsubscript{2} required for methanation to be of biogenic origin or surplus ‘waste CO\textsubscript{2}’, thus not affecting the balance. The potential of biogenic CO\textsubscript{2} is reported in Chapter 4.6.

\textsuperscript{25} Equivalent to a 23% reduction in reference to 1990.

\textsuperscript{26} In principle, accelerated grid development may also be associated with higher CO\textsubscript{2} emissions due to the opportunities for exploitation of these capacities by fossil power plants.
At 112 g CO$_2$ equivalent/kWh, the specific GHG emissions from electricity generation then are expected to be much lower than current levels. Nevertheless, the overall CO$_2$ emissions of road and ship transport would more than double in this case, and the reduction in reference to 1990 would be reduced to a mere 35% (scenario 2) or 55% (scenario 3). Thus, even scenario 3 would clearly fail to achieve the reduction target of 80%. However, please note that the magnitude of demand for PtG is expected to affect the structure of electricity generation in any case. Thus, the consideration of the electricity mix 2050 after the BMU Leitstudie 2011 may serve as an indicator only.

The scenario is based on the current traffic forecast for 2025 that projects significant increases of transport performance particularly in freight transport. In the case that transport performance and especially road freight transport increases less rapidly, the demand for PtG will also be attenuated.

### 5.3.4 Availability of CO$_2$ for methanation

CO$_2$ required for methanation may be obtained from biogenic or industrial processes, or via energy-intensive extraction from ambient air. Present parameters translate into a theoretical
potential of approx. 17 million t (biogenic) and 20 million t (from industrial processes\textsuperscript{27}) per annum in Germany. This would be sufficient to generate approx. 185 TWh\textsubscript{chem} of renewable Power-to-Methane (see Paragraph 4.6.3).

This output is available to satisfy a demand for renewable Power-to-Methane of 350 TWh\textsubscript{chem} in scenario 2 or 140 TWh\textsubscript{chem} in scenario 3. It is evident that the CO\textsubscript{2} demand in a transport scenario based on renewable Power-to-Methane (scenario 2) distinctly exceeds the available supply (biogenic and industrial). To generate the required 350 TWh\textsubscript{chem} renewable Power-to-Methane domestically, either the import of biogenic CO\textsubscript{2} (e.g. in the form of biomass) would be necessary or CO\textsubscript{2} extraction from ambient air would be further increase electricity demand. In contrast, in scenario 3 with higher shares of fuel cell vehicles, the demand for CO\textsubscript{2} could be fully covered with domestic sources.

5.3.5 Conclusions from the scenario analysis

In principle, PtG presents an option for the transport sector to achieve high GHG reductions while simultaneously reducing dependence on fossil energy carriers. In light of the current projections for transport growth rates, particularly in freight transport, increased vehicle efficiency will be insufficient. Only the utilisation of renewable energy in BEVs or via PtG in the form of methane or hydrogen in fuel cells or combustion-engine vehicles allows an ambitious GHG reduction of 80% by the year 2050 in reference to 1990.

In a transport system with a high share of LNG and CNG vehicles fuelled with renewable Power-to-Methane, the energy conversion efficiency chains result in an electricity demand of approx. 600 TWh. This electricity demand is higher than the current overall total (across all sectors) in Germany and would more than double the 2050 electricity demand anticipated in many studies. Thus, the sustainably generated potential of renewable electricity in Germany would in all likelihood be fully exhausted. A distinctly lower electricity demand may be achieved through the substitution of renewable Power-to-Methane-fuelled LNG and CNG vehicles with FCEVs and BEVs. This is due to higher energy conversion efficiencies both during fuel production and supply and fuel utilisation in the vehicle.

\textsuperscript{27} A decisive factor for the environmental assessment of CO\textsubscript{2} from industrial processes is the existence of a causal link between CO\textsubscript{2} generation and subsequent use for methanation.
Excursus: Grid services through Power-to-Gas in transport

In both cases, i.e. with a high share or renewable Power-to-Methane or renewable Power-to-Hydrogen, substantial quantities of hydrogen (and subsequently methane) are required to supply the transport sector. Scenario 2 requires 350 TWh (chemical) renewable Power-to-Methane annually, which is much more than the capacity of the currently installed storage capacity of the German natural gas grid of 220 TWh. In the case that the monthly road transport demand of approx. 29 TWh (chemical) is stored within the gas grid, the required quantity equals about 15% of the volume of the current natural gas storage capacity.

The electricity demand of the transport sector is flexible in time. In principle, this temporal flexibility, in combination with development of additional renewable energy plants, presents an opportunity to act as a further buffer for renewable energies through the additional volumes of hydrogen/methane in storage. PtG plants for fuel production may employ part of the renewable Power-to-Hydrogen or renewable Power-to-Methane for the supply of so-called guaranteed capacity. The quantities of energy that would have to be made available are minor, yet they could secure electricity supply even in situations with high fluctuations of renewables in the system.

The central component for the production of PtG is the electrolysis step. In all likelihood, the earlier break-even of PtG in transport would facilitate the development of hydrogen and methane production for the transport sector, thus reducing costs through mass production.

PtG fuel production may be technically realised in production facilities of all magnitudes. Provision of grid service such as reactive power control, load management or the supply of guaranteed capacity (in combination with reconversion) may be carried out in centralised or distributed units. Thus, great flexibility for the development of future renewable energy systems in the electricity and fuel sectors is achieved.

For these reasons, the transport sector may hold a key position in the energy transition due to the supply of storage capacity and grid services. This pivotal role should be explored in great detail under consideration of the relevant technical and economic parameters. Particular attention should be paid to the question at which points in time certain technologies should be applied in certain sectors to ensure maximum benefit.
Thus, timely consideration is required to ensure that

- an optimal combination of electricity-powered vehicles, FCEVs and conventional LDVs is achieved under consideration of financial, environmental and user aspects;
- required renewable production capacities are in place (assuming economically, technologically and environmentally sustainable conditions; considering both domestic production and imports where appropriate);
- arising demand is satisfied with additional renewable energies wherever possible (even minor contributions of fossil electricity may impair the climate balance considerably, see Figure 9), as well as
- additional measures for the reduction of transport energy demand are promoted (e.g. logistical optimisation and reduction of transport volumes).
6 Stakeholders

A number of industrial branches may potentially show interest in the utilisation of PtG. However, reasons for such interest may differ from sector to sector and primarily focus on hydrogen or synthetic methane, respectively. To learn about different motivations and interests and highlight opportunities for joint development of shared gas infrastructures, the following chapter illustrates the prevailing points of view. The topic is currently subject to intense debate, thus interests among stakeholders may be developing or actively changing at the time of writing. The sectors/industries portrayed here include the electricity industry, the transport sector with the automotive and crude oil industries, the natural gas industry as well as the chemical industry.

6.1 Electricity industry – sufficient potential for energy storage in centralised and distributed settings

The electricity industry was the first to suggest PtG utilisation for energy storage purposes, specifically in analyses on large-scale energy storage in the form of hydrogen [VDE 2008]. Two aspects were of particular importance:

- The development of commercial storage options for fluctuating renewable electricity (utilisation of increasing quantities of excess renewable electricity, optimisation of grid operation and development, participation in the ancillary services power energy market) and
- The utilisation of electricity for the production of an energy carrier suitable for utilisation in other energy consumer sectors. The diversification of business portfolios and the opening up of new markets could be the consequence.

The increasing RE production capacity, particularly for on- and off-shore wind energy in Northern Germany, leads to both interest in the use of inexpensive excess electricity and the need for measures preventing grid shortages. For electricity production, these measures may include the use of excess electricity lost to the grid for the production and storage of hydrogen. For electricity end use, measures may include the supply of electricity (guaranteed capacity) from stored hydrogen in cases of electricity supply bottlenecks.

Grid development frequently lacks public acceptance. In consequence, energy suppliers regard PtG as a medium-term option to alleviate grid bottlenecks (e.g. [VKU 2013]). However, there is common consensus on the fact that PtG does not replace the need for general expansion of the electricity grid. Nonetheless, it could be instrumental to reduce the extent of grid development measures [Bayern 2013]. It is important to distinguish between grid expansion and storage, as the two measures address fundamentally different functions. Grid ex-
pansion permits greater spatial distances between production and consumption site, whereas storage promotes temporal decoupling. A combination of both measures may help to prevent certain grid bottlenecks.

Reconversion of hydrogen from electrolysis on a grand scale is not economically viable in the short- or medium-term due to low energy conversion efficiency (see subchapter 4.4). For climate change mitigation, the option is also relatively unfavourable. Greater emission savings may be achieved through the replacement of ‘grey’ hydrogen for industrial purposes in the near future, or through the operation of hydrogen-fuelled FCEVs in the medium-term. However, local grid shortages may be prevented with storage depots. Further research will be needed here.

In the long-term, or in regard of capacity mechanisms, the reconversion of electricity will be an inherent system component of a primarily renewable energy strategy. Capacity mechanisms should strive to employ renewable concepts in the context of the overall RE development. There are no technological impediments to switch applications currently operated with fossil primary energies to renewable sources. Among the flexible electricity production capacities are gas and steam turbines, gas turbines, gas engines and fuel cells. All of those may be fuelled with renewable energy carriers in the future, thus contributing to guaranteed capacity (in addition to other options). The debate on the required energy industry framework and adequate political measures is just starting to gather momentum.

In addition to hydrogen refuelling stations in demonstration projects, the electricity industry has investigated regional aspects of a hydrogen infrastructure in a number of studies [EnBW 2011]. After the potentials for large-scale storage of hydrogen in salt caverns in Northern Germany were sufficiently explored, initial findings on regional or local storage of hydrogen in Southern Germany are now available. However, economic viability from an overall system perspective, i.e. assuming joint utilisation of several sectors, has not been investigated to date (see Chapter 6.7).

6.2 Passenger cars – hydrogen and fuel cells cut energy demand in half

The automotive industry is currently pursuing a number of strategic PtG approaches. The majority of manufacturers develop hydrogen-fuelled FCEVs, whereas AUDI further supports the development of a PtG project for the production of CNG as vehicle fuel.

The development of hydrogen-fuelled FCEVs is addressed in a considerable number of projects by established car manufacturers with a current focus on Asia. Hyundai was the first car manufacturer to commence the serial production of FCEVs in the summer of 2013 [Hyundai 2013]. The proposed output target amounts to 1000 vehicles in 2015 with an additional 10,000 vehicles following soon after [Hyundai 2013]. Daimler postponed the planned intro-
duction by two years until 2017, and launched a research cooperation on fuel cell development with Ford and Nissan in the spring of 2013. Series production is expected to commence in 2017. Starting in 2017, the three manufacturers intend to launch an initial FCEV series with an output of at least 100,000 vehicles based on a common automobile platform. These plans correspond to 30,000 vehicles per annum and 10,000 vehicles per annum and respective manufacturer. BMW in collaboration with Toyota announced the start of FCEV series production beginning in 2020 [BMW 2013].

Volkswagen (with AUDI) pursues technology development and vehicle demonstrations in preparation for an eventual market launch. Current publications date the introduction to the market after 2020 (Volkswagen acknowledges the advantages of FCEVs in general, however, the company maintains that the existing vehicle fleet is equipped with hybrid and diesel engines able to comply with EC CO₂ standards until at least 2020. In consequence, there is no urgent need for an earlier series launch).

Individual smaller manufacturers like Mitsubishi have not engaged in any FCEV development projects to date (due to lack of funds). Other manufacturers like Fiat (with Chrysler) and PSA have dismissed prior FCEV development strategies. Renault may access novel technology with ease through its corporate link with Nissan due to the fact that Nissan is among the world leaders in this sector. Suzuki is in a similar position due to the corporate investment of GM.

The development pathways for fuel cell technology of individual manufacturers may occasionally appear less than straightforward, and postponed market launch dates may delay broad commercialisation to date. Nonetheless, the genuine long-term continuity in the strategic commitment to fuel cell development should not be overlooked. Although the actual figures have not been made public, the investment of the automotive industry in research and development of fuel cell technology in all likelihood exceeds several billion Euros. Further funds are invested into material, component and process development.

Probably the most important challenge for the marketing of FCEVs for the automotive industry and others is found in the development of a nationwide hydrogen refuelling infrastructure. Daimler is the only manufacturer actively engaging in the ‘H₂ Mobility Initiative’. This initiative

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28 The three manufacturers announced their intentions to produce a six-digit number of first-generation vehicles, i.e. 100,000 vehicles minimum: ‘To achieve competitiveness for FCEVS, Daimler, Ford and Nissan intend to lower engine costs to the level of diesel-hybrid engines, without further specifications. All in all, the three manufacturers aim to produce a six-digit number of vehicles, in collaboration and across the entire lifecycle of the respective vehicles.’ [Daimler 2013]
aims to establish 400 hydrogen refuelling stations across Germany by 2023 [H₂ Mobility 2013]. Most manufacturers see the responsibility for the establishment of a hydrogen infrastructure with the fuel industry (participation in CEP and earlier stages of H₂ Mobility). However, Volkswagen has recently engaged in research on infrastructural basics such as analyses on large-scale storage of hydrogen in salt caverns in Northern Germany [Volkswagen 2012] [NOW 2013-1].

The only manufacturers actively pursuing the production and utilisation of renewable Power-to-Methane to date is AUDI. For the novel natural gas vehicle A3 G-tron, AUDI offers a wind gas package for a premium, i.e. the supply with synthetic methane from renewable electricity. These premium customers receive methane derived from renewable Power-to-Hydrogen from an offshore wind park in an ETOGAS plant (methanation with CO₂ from biomass). The methane produced by ETOGAS is fed into the natural gas grid. However, according to AUDI, the current legislation on end user fees for electricity consumers renders the projects unsustainable at present.

The use of renewable Power-to-Hydrogen blended into natural gas utilised to fuel CNG vehicles is currently not feasible due to the fact that the hydrogen content in CNG for motor vehicles complying with current regulations for engine and tank is limited to 2% at present.

In comparison with BEVs, CNG-fuelled vehicles or FCEVs are associated with a distinct advantage for the automotive industry. In case of sufficient infrastructure, their mileage is not markedly limited, which strongly improves user acceptance. In contrast, the fact that the renewable benefits associated with renewable methane fuel well-to-tank are not credited in the calculation of direct emissions for fleet standards is a disadvantage for the automotive industry. Thus, renewable Power-to-Methane does not contribute to the compliance with emission standards. Similar disadvantages apply for the blending of renewable Power-to-Hydrogen into CNG for passenger cars, in the case that future CNG vehicles will be equipped with technology allowing higher hydrogen contents. The range of CNG models on offer is currently relatively narrow. Whether manufacturers intend to change this situation remains to be seen.

29 Pressure tanks in natural gas vehicles have not been approved for hydrogen contents exceeding 2 vol% to date.
30 In the future, operators may ask for crediting of RE gas as ‘eco-innovation’ according to Article 12 EC/443/2009.
6.3 HDVs – methane offers potential for short-term fuel diversification in long-distance transport

In contrast to passenger cars, the methane-fuelled operation of HDVs is associated with mileage constraints. Therefore, liquefied methane (LNG) is preferable over CNG due to its higher energy density. At present, there are several LNG vehicles on the market. Some of these are fitted with dual-fuel technology\(^3\) (i.e. a certain diesel content is required, see Chapter 4.2). Manufacturers are striving to increase efficiency in these engines as well as reduce pollutant emissions (particularly in dual-fuel engines).

The operation of city buses with CNG is very common. Advantages include low local pollutant and noise emissions, and the natural gas pressure tank may be installed on the bus roof with ease. Abundant space on top of buses facilitates installation in comparison with HDVs. In mid-2013, 1500 city buses and about 90 natural gas-fuelled medium- to heavy-duty vehicles were in operation in Germany [NGVAE 2014].

The benefits of alternative fuels in buses are even stronger in favour of fuel cell city buses (virtually free of pollutant and noise emissions, roof integration of storage tanks). More than 100 of the buses have been test-driven for millions of kilometres in pilot projects by a number of manufacturers. Series introduction by 2020 is intended.

Manufacturers and their activities:

CNG- and LPG-fuelled HDVs are offered by a number of manufacturers. CNG-HDVs are already available on the market for transport services and waste management, communal and specialised applications. Manufacturers include Daimler, Iveco, MAN, Renault, Scania and Volvo. Virtually all of these vehicles are equipped with Otto engines.

In long-distance road freight transport particularly in the Netherlands and the United Kingdom, pilot fleets of several hundred LNG-HDVs have been introduced. Dual-fuel engines with EURO V-standard were introduced by e.g. Volvo and Hardstaff (conversion of e.g. MB Actros). Iveco specialises in Otto engine HDVs for long-distance transport but does not engage in development of dual-fuel technology.

At present, there is virtually no information on the development of potentially hydrogen-fuelled HDVs. In the USA, a small number of fuel cell-equipped HDVs in container haulage and distribution are operated in the port of Los Angeles. These vehicles were converted by

\(^3\) Methane and diesel.
Vision Motors (‘Tyrano’) [Vision 2013]. Data on these vehicles were used in the present study.

Fuel cell electric buses are currently developed by Daimler/Evobus (Germany), Hino/Toyota (Japan), SAIC (China), Solaris (Poland), TuttoTransporti (Brazil), Van Hool (Belgium) and VDL/Phileas (Netherlands) and tested in pilot fleets.

6.4 Crude oil industry – application of knowledge on process technology
The crude oil industry has an impressive command of process technology concerning the industrial handling of natural gas for both the inexpensive production of hydrogen from natural gas and subsequent use for hydration of long-chain hydrocarbons. Moreover, the crude oil industry is the primary operator of refuelling stations for conventional fuels. It was instrumental in the introduction of CNG fuel into existing trade structures.

A number of enterprises in the crude oil industry have turned their knowledge on process technology into expertise for the development and operation of hydrogen refuelling stations [Total 2012]. This expertise may be crucial for PtG concepts in the search for long-term business models outside of the supply of conventional, i.e. fossil, or biomass-derived fuels. Consumers would benefit from continued supply via established fuel infrastructures, extended by the supply of the fuel alternatives CNG and hydrogen.

However, the crude oil industry currently positions itself on the periphery of the PtG debate. The future trajectory of hydrogen demand in transport is uncertain, and renewable Power-to-Methane is not expected to be competitive with natural gas in the foreseeable future as long as the current framework remains in place. Nonetheless, opportunities for multiple crediting of PtG under the biofuels quota could substantially increase the interest of the crude oil industry.

6.5 Natural gas industry – a natural gas grid is already in place, including storage
Natural gas sales for the supply of private households in Germany have been in distinct decline since 2003 with the exception of 2010 [ARGE 2013]. This trend is sustainable as demonstrated by the trajectory of heat supply in new buildings. In 2000, about 77% of heating appliances were operated with natural gas. In 2012, this figure had dropped to 48% in favour of electric heat pumps, district heating and pellet stoves [BDEW 2012]. The natural gas industry strives to keep specific natural gas distribution costs in the established grid low. In consequence, the natural gas industry recognises PtG as a novel market and an additional option for an alternative use of the grid. Without delay, PtG may be instrumental in support-
ing the electricity sector in its strive for greater flexibility of electricity supply from renewable energies.

The storage capacity of the natural gas grid offers the potential to use the grid in collaboration with partners from the electricity industry, thus allowing the development of joint business opportunities for easing the strain of the electricity grid. The two industries frequently operate as joint ventures (e.g. E.ON, EnBW, EWE, Thüga). The electricity industry has substantial transport capacities, yet it lacks storage capacity. Current hydro-pumped storage stations in Germany are equipped with an energy storage capacity of only about 38 GWh, whereas recent natural gas storage depots may contain approx. 220 TWh.

There are several options for the integration of PtG into the natural gas industry. The first two options have already been analysed in great detail for implementation within Germany [DVGW 2013-2] or joint analyses have been initiated at the European level [DVGW 2013-3]:

- **Renewable hydrogen in natural gas blends**: a broad analysis explored the question of maximum hydrogen content for blending into the natural gas grid across all relevant technologies [DVGW 2013-3]. The study revealed that some gas operations may not tolerate any blending at present (reservoir rock, gas turbines), whereas others may accommodate a hydrogen content of 2 vol% (natural gas pressure tanks in CNG-fuelled vehicles). However, the analyses also reveals that minor measures (e.g. conversion, retroactive analysis/certification) may allow higher blends in excess of 10 vol% or more [DVGW 2013-2].

- **Methanation of renewable hydrogen and subsequent feed-in as desired**: from the natural gas grid operator perspective, methanation represents the superior PtG application considering technological, infrastructural and safety aspects. However, a number of disadvantages associated with methanation should not be ignored. For instance, (a) an additional 10% loss in energy conversion efficiency for methanation from hydrogen and CO₂, (b) disqualification for the supply of FCEVs and thus, a major share of transport performance, ignoring that FCEVs are twice as efficient as CNG-fuelled vehicles and (c) the limited renewable CO₂ potentials and thus, limited overall potentials of synthetic methane via PtG.

- Another option not yet analysed in great detail may be the successive conversion of parts of the natural gas grid to operation with 100% hydrogen. Analyses [SWM 1993], [NaturalHy 2009] and current demonstration projects [Lolland 2013] have demonstrated the feasibility of this concept in principle. Moreover, a proof-of-concept was provided for local, distributed energy supply. In the future, interconnected hydrogen pockets could be integrated into the industrial 100% hydrogen grid in advanced development stages or connected to parts of natural gas grid converted to 100% hydrogen. Moreo-
ver, synergies through linkage of hydrogen refuelling stations with distributed supply and stationary energy consumers could arise. However, the natural gas industry is not committed to this approach at present.

In principle, the natural gas industry considers the transport sector a relevant consumer independent of PtG despite the fact that prior collaboration with the automotive industry has not resulted in the desired market penetration with CNG-fuelled vehicles.

6.6 Chemical industry – advance hydrogen infrastructure, reduce GHG-emissions

At present, hydrogen already qualifies as a major feedstock for the chemical industry at a large scale. Although the market volume is difficult to assess, [SRI 201] estimated a turnover of approx. 9 Mt/a in Europe with the major part used for the hydration of long-chain hydrocarbons. Hydrogen consumption in Germany amounts to approx. 2700 to 3600 kt/a, representing a disproportionately large share among the hydrogen-consuming industries across Europe. The energy contained in these quantities of hydrogen amounts to approx. 90 to 120 TWh. This is equal to about 10-13% of the energy content of the total natural gas consumption in Germany in 2012 [BDEW 2013]. Out of the overall total, 56% are consumed in refineries that generally produce hydrogen on-site. In light of these considerable quantities, the industry in question would be eligible in principle to participate in PtG concepts for the production of hydrogen from renewable electricity, or its storage by providing existing hydrogen infrastructures and operational know-how.

Industrial demand for hydrogen is currently supplied from inexpensive fossil energy (e.g. via steam reforming from natural gas or partial oxidation of heavy fuel oil (HFO)) and thus associated with CO₂ emissions. Future pricing of CO₂ emissions certificates may render the commercial renewable production of hydrogen from excess wind electricity via electrolysis economically viable. The chemical industry would be very receptive to such renewable hydrogen. As a first step, the chemical industry in the Germany Lower Elbe region collaborated on an analysis of technical and economic potentials [ChemCoast 2013].

Climate change mitigation efforts would greatly benefit from the substitution of ‘grey’ hydrogen with renewable hydrogen in the chemical industry due to the considerable GHG reduction potential. In the Lower Elbe region alone, industrial production/demand was quantified to amount to 230 kt hydrogen per annum. Extrapolated to the nationwide demand in Germany, the hydrogen substitution potential of the industry in principle equals the total overall demand for hydrogen of 90 to 120 TWh/a.

A number of chemical processes generate hydrogen as a by-product or waste material. At present, its recovery and utilisation as a chemical is not always profitable, thus excess hy-
drogen is sometimes merely utilised for heat generation in gas turbines. Increased hydrogen
demand, e.g. for FCEVs, could result in a lucrative market for the sale of waste hydrogen,
which in turn would lead to substitution of heat energy with natural gas\textsuperscript{32}. However, waste
hydrogen in a hydrogen economy may generally be considered negligible due to the fact that
the chemical industry primarily qualifies as a hydrogen consumer.

In addition to established hydrogen production pathways (steam methane reforming or coal
gasification, partial oxidation of HFO) and RE electrolysis, further novel technologies could
emerge in the future. The Linde Company is currently developing a concept for the produc-
tion of hydrogen from glycerine, a by-product of biodiesel production\textsuperscript{33}. However, similar to
by-product hydrogen, quantities of ‘waste glycerine’ are also limited and would support no
more than a six-digit number of FCEVs in Germany.

Finally, there are additional approaches for the production of chemical base materials from
electricity: Evonik is currently testing a process for the separation of methane into hydrogen
and acetylene ($\text{C}_2\text{H}_2$) under application of electricity [Markowz 2013]. In combination with a
gas power plant that could reconvert the hydrogen produced into electricity on demand, a
greater variety of operational modes and a potentially higher utilisation of the plant could be
achieved. The electricity demand could be adapted to the current renewable energy supply.

\section*{6.7 Aspects of Power-to-Gas utilisation across sectors}

Socio-economic studies to date based on current assumptions reveal that profitable produc-
tion of hydrogen from electrolysis may only be expected with utilisation in the transport sector
(see subchapter 4.4). There was no evidence for profitability in the short- or medium-term for
all other energy sectors (industry, electricity, natural gas economy). The same outcome ap-
plies to the use of synthetic methane via PtG.

However, future profits could increasingly depend on an intersectoral use of hydrogen pro-
duction and infrastructure elements (transport/distribution and storage). These advantages
are not readily accessible and require long-term coordination between sectors and relevant
stakeholders. At present, even the relevant process scales are lacking. Moreover, there is
hardly any definitive information on market trajectories or policy measures defining sector-
specific energy and emissions targets. In consequence, the development of a joint energy

\textsuperscript{32} \url{http://www.zeit.de/auto/2012-02/brennstoffzelle-wasserstoff/seite-3}
\textsuperscript{33} \url{http://www.heise.de/tr/artikel/Wasserstoff-marsch-1726680.html}
infrastructure will require coordinated efforts of all sectors. These are currently emerging, although at a very early stage.

One such effort for the case of synthetic methane via PtG is exemplified by the joint methanation project of AUDI in collaboration with the natural gas industry in Werlte, Germany. Another example may be found in the collaboration of companies from several energy sectors for the application of hydrogen-based PtG in the hybrid power plant project located at the future Berlin Airport (BER). Practical implementation in small-scale projects should be run in parallel with dedicated analyses demonstrating the profitability of novel business opportunities and future collaborations.

A detailed overview of all PtG demonstration projects currently under way may be found in Chapter 7 and in Appendix III.
7 Activities

The following chapter portrays PtG activities in Germany, Europe and around the world. A list of all relevant studies would be very elaborate, thus we decided to focus on the representation of demonstration projects. We consider these as reliable indicators for the individual level of activity. We included both renewable Power-to-Methane and renewable Power-to-Hydrogen projects with special attention to links to the transport sector as applicable.

7.1 Germany

Activities for the demonstration of hydrogen production via electrolysis from solar electricity in Germany commenced in 1985 with the HySolar Project in a collaboration of the German Federal State Baden-Württemberg and Saudi Arabia. In 1987, the Solar Wasserstoff Bayern Project followed. Further projects with on-site hydrogen production and hydrogen refuelling stations (primarily for test vehicles in public transport) were carried out at Munich Airport, in Berlin and Hamburg. The motivation behind the projects changed over the years. Early efforts were initiated in response to the oil crises of the 1970s and the nuclear accidents in the 1980s. Subsequent demonstration projects were launched when announcements of the automotive industry heralded the development of hydrogen vehicles and associated refuelling infrastructure in the early 1990s.

The present study identified 27 individual projects currently in preparation or under way, including eight with an explicit connection to the transport sector. Figure 20 illustrates the distribution across Germany. Projects with a transport sector connection are denoted by dispenser icons; the project in Werlte is providing PtCH₄ as transportation fuel by feeding it into the natural gas grid and selling certificates to CNG refuelling stations. All projects are presented in detail in the Appendix. The compilation is structured to distinguish between renewable Power-to-Methane, renewable Power-to-Hydrogen and project relevant to the transport sector.

Whereas PtG projects with renewable Power-to-Methane connection are usually born from the idea to be immediately applicable and close to the market, the ambitions and driving forces behind renewable Power-to-Hydrogen-based projects fall into two categories:

34 The nuclear accident at Three-Mile Island took place in 1979, at the end of the 1970s.
35 The demonstration plants of MicrobEnergie are exploring the profitability of biogas plant upgrading by increasing energy output through utilisation of local excess wind energy. The SolarFuel (now ETO-
Renewable Power-to-Hydrogen for the production of fuels for the transport sector including the option for distributed supply of hydrogen for stationary purposes,

- Utilisation of inexpensive excess wind electricity or other favourable local conditions\textsuperscript{36}, to demonstrate the concept of an energy future rich in renewables in distributed total energy supply approaches. The ENERTRAG hybrid power plant project has political support and may serve as a role model here.

The German strategy on PtG has been stated in the strategic paper of the National Innovation Programme Hydrogen and Fuel Cells (Nationales Innovationsprogramm Wasserstoff und Brennstoffzellen (NIP)) in June 2013 [NOW 2013-2]:

\textit{Hydrogen can be simply produced from renewable sources and then stored. Fuel cells enable highly efficient and emission-free conversion to electricity and heat. In addition, with new products, services and applications, they contribute to securing added value and employment in Germany and to reducing the import of fossil fuels as a significant cost driver in today’s energy supply. This technology will therefore assume an important bridging function in the interlinking of hitherto separate systems for electricity generation (from renewable energies) and fuel supply for transport.}

\textsuperscript{36}E.g. the projects Reußenköge and ENERTRAG hybrid power plant are making use of existing biogas infrastructure whereas the WESpe project utilises an underground salt cavern close by.
Figure 20: Map of Power-to-Gas projects in Germany (Source: LBST)
7.2 Europe

The current wealth of demonstration projects, technology and economy analyses and events on Power-to-Gas suggests that Europe, with Germany as the forerunner, is leading the way at present. The main driving forces in all involved countries are the agendas for the development of renewable energies, particularly for renewable electricity. These are expected to lead to substantial increases of renewable electricity shares in the long run, thus prompting a debate on long-term storage solutions. In this context, there is currently no alternative to PtG (except in countries where topographic conditions allow large-scale pumped hydro storage capacity, e.g. Norway). A detailed discussion of the relevance of both the spatial imbalance between energy production and energy demand, and the temporal periods that require bridging may be found in [SFV 2013]. Outside of energy storage, the bridging of these temporal gaps may be only partly achieved with other flexibility measures, or only in the case of limited renewable electricity quantities in the grid. In particular, the limits of potential additional demand side management and likely obstacles for grid expansion (costs, acceptance) are pointed out.

Similar debates are under way in countries with high shares of renewable energies (e.g. Denmark, Spain) or pronounced energy dependency (e.g. Japan), although the dispute there is less heated. In Denmark, a number of options are under consideration. For instance, in the wind hydrogen project Lolland (see Appendix), the application of hydrogen from wind energy for feed-in into the gas grid to supply households with small fuel cells is demonstrated in everyday use. Moreover, the coupling of wind hydrogen plants for energy storage at hydrogen refuelling stations is currently studied.

The European research project HyUnder aims to investigate the applicability of German findings that identify underground large-scale hydrogen storage as a vital component for the success of PtG for other European countries or regions. This project confirms Germany as the forerunner leading the PtG field. In addition to Germany offering expertise and competence in analysis, Spain, the Netherlands, France, the United Kingdom and Romania are participating in the project. Essential industry partners from different branches (energy, processing, automotive) and regional representatives are part of the project either as full (12) or supporting (17) partners [HyUnder 2014]. Results for presentation to the general public are expected for spring 2014. An interim result of the project identifies similar conditions and op-

37 http://www.lg-action.eu/fileadmin/template/projects/lg-action/files/it/LG_Ac
ction_case_Lolland_climate_plan_DE.pdf
portunities for underground storage of substantial natural gas and hydrogen volumes in salt caverns particularly in the Netherlands. The Dutch energy market and the local energy infrastructure are also very similar to those in Germany. Thus, close collaboration between Germany and the Netherlands on PtG applications is highly recommended.

The present study identified 11 PtG projects that are reported separately for renewable Power-to-Hydrogen and renewable Power-to-Methane in the Appendix. Furthermore, 14 hydrogen refuelling station projects are included. In principle, these would allow PtG fuel supply, i.e. there is a connection to the transport sector. The projects reported here only include hydrogen refuelling stations with on-site electrolysis.

7.3 Global

Outside of Europe, four further PtG projects were identified, although there is no record of any methanation projects. Moreover, 27 hydrogen refuelling station projects are listed. Hydrogen is produced on-site, and could in principle be used for other PtG applications. Further details on these projects may be found in the Appendix.

Japan’s attitude towards PtG is particularly interesting. In 2009, the Research Association of Hydrogen Supply Utilization Technology (HySUT) was founded38 by notable players from the industry. This institution investigates the use of hydrogen as a novel energy carrier for stationary and mobile applications. It is noteworthy that in addition to all ingredients for the utilisation of hydrogen (Gas), the ‘Power-to-’ aspect appears to be of minor importance. In consequence, Japan is approaching the PtG supply from a different angle altogether. All aspects of the currently growing Japanese interest in fossil and renewable PtG electricity pathways are subsumed under the term PtG. Recent announcements of the Japanese automotive industry report another interesting development. Home refuelling of FCEVs from solar sources has long been researched and demonstrated in Japan and California39. However, it has been shown recently that parked FCVEs are able to supply households in emergency black-out situations with electricity for several days40. It may be assumed that these intended developments are motivated by the specific environmental conditions (seismic hazard area), particularly since the events in and around Fukushima in 2011.

38 http://hysut.or.jp/en/index.html
40 “Fully fueled, the vehicle can provide enough electricity to meet the daily needs of an average Japanese home (10 kWh) for more than one week.” http://www.toyota-global.com/innovation/environmental_technology/fuelcell_vehicle/
8 Recommendations for action

For the exploitation of Power-to-Hydrogen and Power-to-Methane potentials (PtG) in the transport sector, three major fields of action are relevant in the immediate and foreseeable future:

Firstly, technological maturity may only be reached with additional dedicated research, development and validation efforts.

Secondly, preparation of the market includes the identification of economically attractive applications for PtG technology and the development of relevant business models. Synergies with other energy sectors should be integrated wherever possible.

Thirdly, the political framework has to be modified to support business models in line with the political PtG agenda and the targets specified there.

8.1 Need for R&D

Hydrogen production is the key technology for PtG. Further improvement of efficiency increases and cost reduction potentials for the respective electrolysis technologies is paramount and should be the central focus.

The conversion of hydrogen with CO and CO$_2$ to methane via methanation has been commercially available for more than 50 years, e.g. the conversion of coke oven gas to methane. However, additional validation data are required for the operation of methanation plants with fluctuating renewable energies, taking extended idle periods and associated heat management strategies into account.

The utilisation of biogenic CO$_2$ is favourable in the ecologically sustainable conversion of hydrogen to methane, e.g. via separate methanation or in-situ fermentation within the biogas plant. Universal supply of the transport sector with Power-to-Methane is not achievable with the national biogenic potentials analysed here. Additional CO$_2$ potentials need to be developed and assessed in an ecological and economic context.

The situation for vehicle engines varies depending on the individual drive concept:

CNG-fuelled internal combustion engines have been available on the market for both passenger cars and HDVs for some time. Whereas user acceptance of passenger cars could be improved with greater model diversity, HDV engines require further development. Moreover, CNG-fuelled vehicles could potentially achieve efficiency optimisations similar to those in petrol-fuelled vehicles. The optimisation potential should be fully exploited. In compliance with EURO VI standards, hybridisation of CNG-fuelled engines may be interpreted as a stage of the evolution towards electrification of vehicle engines.
In contrast, **fuel cell electric engines** for passenger cars are as yet only on the verge of commercial production. Major progress has been made concerning the improvement of service life, power density and cost reductions. Moreover, the tank weight could be considerably reduced. Additional substantial cost reductions are required for commercial series production, analogous to photovoltaic cells and modules. As a perspective for city buses and future HDVs, fuel cell electric engine development should be advanced, in particular with respect to improved service life. Due to the fact that FCEVs are classified as hybrid vehicles, they benefit from progress in battery development for BEVs and supercapacitors for stationary energy storage purposes.

Increasing shares of (fluctuating) renewable electricity continue to shift the focus on interfaces and synergies between different energy sectors and their respective infrastructure components. Novel conceptual approaches required here are not limited to a mere need for technology development. In fact, they are subject to a long-standing strategic debate and call for a suitable regulatory framework. In this context, issues demanding attention include the modularisation of facilities and their integration into the energy or electricity markets. The integration of distributed PtG plants in the context of both electricity sector and fuel supply should be analysed in greater detail to identify synergy potentials for energy and transport.

Moreover, **technical standards and regulations** for grid operation should undergo review and potentially revision, particularly regarding the feed-in of hydrogen into the natural gas grid or the operation of individual grid sections with fluctuating hydrogen blend quotas. Additional technological and economic analyses exploring options for the potential conversion of natural gas grid sections to dedicated hydrogen use are needed here, along with in-depth investigation of infrastructure synergies with existing industrial hydrogen grids. There is further need for research and development on hydrogen refuelling stations to simplify and standardise approval, and optimise both single components and the overall operation of the systems.

The successful introduction of PtG into the transport sector combined with other sectors could raise the demand for renewable electricity to an extent that sustainable domestic potentials are exceeded. In this case, the development of additional international capacities and as a consequence, renewable energy imports have to be ascertained. In principle, transport in the form of electricity via high-voltage direct current (HVDC), or hydrogen or methane may be considered.
8.2 Preparation of the market

The preparation of the market requires further detailed analyses on the economic viability of hydrogen use in different markets. The consideration of indirect impacts of PtG and their economic significance is crucial, yet these aspects have been largely ignored to date. From a socio-economic perspective, the identification of infrastructure synergies is paramount due to the fact that hydrogen and methane may be offered on different markets. For instance, they may be applied as energy carriers in transport, chemical feedstocks for the industry; they may further guarantee capacity via reconversion etc. In this context, several time horizons should be considered.

A number of effects of PtG use in transport require further analyses to investigate economic aspects of a long-term strategy for the introduction of PtG. Among these effects are cost reductions associated with greater flexibility for electricity demand, savings from avoiding conventional peaking power plants and potential cost reductions for the electricity grid development resulting from an overall energy system optimisation. Moreover, synergies and funding opportunities for PtG from infrastructure investments already scheduled for the medium-term should be explored, e.g. in context of the EU Alternative Fuels Infrastructure Directive Clean Power for Transport (Status 12/2013: draft).

It is essential that measures for market preparation build on insights from pilot projects already realised or in the planning stage. Stakeholders in the different regions may aid the process by spearheading analyses on local conditions to facilitate the introduction of PtG. The dialogue between stakeholders should be encouraged to identify synergies early on and promote stakeholder collaborations. Moreover, international PtG activities should be monitored with great care, particularly in other European countries and in Japan.

Market preparation of centralised PtG plants should be mindful of the fact that considerable lead time may be required, e.g. for the construction of salt cavern storage that takes up to ten years from decision making to a fully operational facility. In consequence, another important pillar may be found in distributed PtG concepts, e.g. directly connected to hydrogen refuelling stations. Moreover, distributed solutions may promote RE integration at low-voltage distribution grid level and may be utilised for the supply of distributed stationary applications.

In addition to the technological questions that need answering, business models for development, expansion and operation of PtG infrastructures (grid and refuelling stations) are required. Synthetic methane benefits from an established natural gas grid and refuelling station infrastructure. For hydrogen refuelling stations, the first steps towards commercialisation have been made. Here, initial findings from business models need to be assessed and compared to alternative approaches in the near future. In this context, full advantage should be taken of established structures for European and international collaboration (Hydrogen Infra-
structure for Transport – HIT, and International Partnership for Hydrogen in the Economy – IPHE, respectively). A German national stand-alone effort for the establishment of a hydrogen refuelling station infrastructure is unlikely to succeed.

8.3 Political measures

The scenarios in this study reveal PtG as a favourable option for the transport sector:

- to significantly reduce GHG emissions,
- to minimise oil import dependency through fuel diversification,
- to promote market penetration with alternative drive concepts and
- to accommodate the dynamics of the Energy Transition, and support future RE development with the provision of system services.

With the introduction of PtG, the transport sector could act as an essential driver for the continuing development of (fluctuating) renewable energies. To realise the full PtG potential, the following aspects are pivotal for design of the framework.

Stipulation of GHG emissions targets

The development of a definitive strategy for the introduction of PtG into the transport sector challenges politics to stipulate unambiguous targets for the reduction of GHG emissions from transport in the timeframe to 2050, as already established for other energy sectors.

Establishment of prerequisites for the realisation of environmental benefits of PtG

GHG savings in transport due to implementation of PtG are only feasible if electrolysis is operated at least partly with additional renewable energies or excess electricity quantities from future renewable energies that would otherwise be lost to the grid. PtG plants may facilitate the integration of RE electricity into the electricity grid with system services. Clarification is needed on the acceptability of partial use of ‘grey’ electricity obtained from the general electricity market in the market preparation stage. In any case, instruments for the reliable quantification of GHG savings potentials associated with PtG fuels should be developed as soon as possible. Based on these instruments, an appropriate framework for subsidies and incentives should be devised, including regulatory measures, quotas etc.
Integration of PtG into fuel legislation

At present, the German dena platform ‘Power to Gas’\textsuperscript{41} demands multiple crediting under the German Biofuels Quota, thus highlighting an opportunity to support renewable PtG in transport. A number of aspects need to be considered or clarified in this context:

- GHG reductions targets for PtG fuels should be defined in comparison with the conventional reference fuel. In the process, electricity supply pathways and impacts on the energy system need to be factored in. The goal should be the incorporation of targets for different PtG pathways into the EU Renewables Directive (RED) (transparent crediting methodology, reliable verification procedure).

- The designation of energy quantities classified as ‘CO\textsubscript{2} neutral’ should be transparent and obvious for end users. Evidence for additionality resulting from renewable electricity production or for the demonstrated integration of substantial quantities of renewable electricity otherwise lost to the grid should be straightforward.

- Special benefits or incentives, e.g. for market preparation purposes (such as multiple crediting towards the biofuel quota) should be designed degressively and adjustable, and should be applied for a limited period of time only. Ten years of experience under the German Renewable Energies Act may provide guidance on how to balance flexibility for adaptation with reliable planning for all relevant stakeholders.

The EU Renewables Directive (RED) seeks to achieve a 10% share of renewables of the final energy consumption in transport by 2020. In case of multiple crediting of PtG fuels under this quota, the following aspects should be taken into consideration:

- The credited PtG quantity should be determined equivalent to the share of renewable electricity used, comparable to the crediting of directly used electricity for transport.

- Hydrogen and methane have to be considered separately: In the case of hydrogen, multiple crediting can be justified by the higher efficiency of fuel cell engines; BEVs are already subject to similar regulations. In contrast, these criteria do not apply for synthetic methane.

- Multiple crediting as an instrument facilitating market launch should be applied for a limited time only.

\textsuperscript{41} Dena Strategy Platform Power to Gas: „Eckpunktepapier. Der Beitrag von Power to Gas zur Erreichung der energiepolitischen Zielstellungen im Kontext der Energiewende.” Berlin, 04.11.2013
Review of distribution and share of costs

At present, there is a legal dispute on the 20-year exemption of hydrogen from water electrolysis or methane from electrolysis and subsequent methanation from grid end user fees after §118 paragraph 6. The dispute arises from the fact that in the case of PtG, the absorbed electric energy is not necessarily returned to the grid. Reliable exemption from grid end user fees for non-returning PtG plants should be established as a first step.

Relevant contributions of PtG technology to GHG reductions require construction of additional facilities for the production of renewable electricity. In principle, the transport sector may be expected to contribute to the funding of those facilities as appropriate to support its specific needs. Interim exemptions from cost allocation to foster the introduction of PtG should be discussed. This particularly applies to dedicated renewable power plants with direct connection to PtG production sites.

Funding and funding instruments during implementation

A substantial impediment for a transformation leading to a system based on PtG fuels are the considerable up-front costs, i.e. for the establishment of infrastructure or required electrolyzers. If such a transformation is desired, appropriate incentives need to be presented (e.g. a cost allocation system analogous to German Renewable Energies Act). In this context, stimuli from national and international debate should be heeded and brought to the attention of relevant stakeholder groups.

Supply of renewable electricity for PtG in transport

The scope of a PtG strategy for the transport sector based on renewable energies should seek an upward adjustment of existing national development targets for renewable electricity as stipulated in the German Renewable Energies Act early on. The primary focus of the transport sector should be on dedicated expansion of additional capacities for renewable energies.

Distributed PtG for fuel supply allows the development of additional RE capacities without additional grid expansion, which is lacking public acceptance. One conceivable measure would be the equipment of public transport fleets with fuel cell electric engines, particularly in regions with high shares of (fluctuating) renewable energies. Synergies with electricity and heat supply potentially exist, however, cost and benefits (regarding CO₂ savings) in comparison with direct feed-in of the renewable electricity into the grid via grid expansion should be considered carefully.
Optimisation of the transport sector

When considering PtG, FCEVs are superior to methane-operated internal combustion engines with respect to energy efficiency and pollutant emissions. Political support for this field and for the establishment of a hydrogen infrastructure should be sustained and advanced. However, advantages associated with FECVs require documentation in LCAs including the entire supply pathway.

In the case that future transport is operated primarily with PtG energy carriers, the overall electricity demand will increase in magnitudes of 50% to 100% in reference to current electricity demand. This additional demand for renewable electricity is associated with enormous challenges regarding planning, economy and infrastructure. In consequence, all available measures for the reduction of transport energy demand and increase of vehicle efficiency should be exhausted to the maximum possible extent.

Advancement of international collaboration

The use of economic PtG synergies depends heavily on the integration of the transport sector into an overall German energy strategy. A crucial instrument here is the coordination across sectors and political departments. Moreover, politics should strive to initiate and foster collaboration with countries with similar PtG interests and conditions for the implementation of relevant technology (e.g. the Netherlands within Europe, and internationally Japan).
Appendix I: Detailed assumptions on the energy chains investigated in this study

Petrol and diesel fuel from crude oil

Petrol and diesel supply was modelled based on assumptions adopted from [JEC 2013]. Pollutant emissions from crude oil production were derived from [ETSU 1996]; emissions from crude oil transport from [ÖkoInventare 1996] and crude oil refinery pollutants were adopted from [FEA 1999]. In addition, pollutant emissions from fuel distribution including electricity consumption of refuelling stations need to be taken into account. Evaporation losses during storage and vehicle refuelling were calculated after [Krause 2002].

Table 10: Energy use and emissions from petrol and diesel supply from crude oil in 2010

<table>
<thead>
<tr>
<th></th>
<th>Unit</th>
<th>Petrol</th>
<th>Diesel</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy use</td>
<td>MJ_PEFUEL</td>
<td>1.19</td>
<td>1.21</td>
</tr>
<tr>
<td>Emissions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td>g/MJ</td>
<td>13.1</td>
<td>14.6</td>
</tr>
<tr>
<td>CH₄</td>
<td>g/MJ</td>
<td>0.028</td>
<td>0.029</td>
</tr>
<tr>
<td>N₂O</td>
<td>g/MJ</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>NMVOC</td>
<td>g/MJ</td>
<td>0.053</td>
<td>0.025</td>
</tr>
<tr>
<td>NOₓ</td>
<td>g/MJ</td>
<td>0.037</td>
<td>0.040</td>
</tr>
<tr>
<td>SO₂</td>
<td>g/MJ</td>
<td>0.028</td>
<td>0.031</td>
</tr>
<tr>
<td>CO</td>
<td>g/MJ</td>
<td>0.009</td>
<td>0.010</td>
</tr>
<tr>
<td>Dust/ particulate matter</td>
<td>g/MJ</td>
<td>0.001</td>
<td>0.001</td>
</tr>
</tbody>
</table>

PE: Primary energy

The methodology of the JEC Consortium (JRC, EUCAR, CONCAWE) based on the 'marginal' production of gasoline or diesel, i.e. the additional energy consumption and associated GHG emissions for the production of one additional unit of petrol or one additional unit of diesel in a crude oil refinery, results in slightly lower GHG emissions for petrol in comparison with diesel.

The combustion of petrol results in 73.3 g CO₂/MJ fuel, whereas diesel combustion is associated with about 73.2 g/MJ fuel.

The costs for petrol and diesel were calculated based on the assumptions for the price of crude oil in this study, i.e. 124 to 250 US$/bbl (93 to 188 €/bbl or 16.2 to 32.8 €/GJ). The lower threshold for the crude oil price was adopted from [IEA 2013]; the upper threshold was reported in [GermanHy 2008]. The costs for natural gas refineries, the fuel distribution and refuelling stations were derived from [JEC 2007].
Table 11: Costs for petrol and diesel fuel (excl. tax)

<table>
<thead>
<tr>
<th></th>
<th>Unit</th>
<th>Lower heating value</th>
<th>Higher heating value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Petrol</strong></td>
<td>€/l</td>
<td>0.65</td>
<td>1.22</td>
</tr>
<tr>
<td></td>
<td>€/kg</td>
<td>0.87</td>
<td>1.64</td>
</tr>
<tr>
<td></td>
<td>€/kWh\textsubscript{LHV}</td>
<td>0.073</td>
<td>0.137</td>
</tr>
<tr>
<td></td>
<td>€/GJ\textsubscript{LHV}</td>
<td>20.2</td>
<td>38.0</td>
</tr>
<tr>
<td><strong>Diesel</strong></td>
<td>€/l</td>
<td>0.74</td>
<td>1.39</td>
</tr>
<tr>
<td></td>
<td>€/kg</td>
<td>0.89</td>
<td>1.67</td>
</tr>
<tr>
<td></td>
<td>€/kWh\textsubscript{LHV}</td>
<td>0.074</td>
<td>0.139</td>
</tr>
<tr>
<td></td>
<td>€/GJ\textsubscript{LHV}</td>
<td>20.5</td>
<td>38.7</td>
</tr>
</tbody>
</table>

CNG from natural gas

Natural gas is extracted and upgraded directly on-site at the natural gas field. The associated energy demand and GHG emissions were adopted from [JEC 2013]. Air pollutant emissions were derived from [ETSU 1996].

Table 12: Energy flows and emissions from natural gas production and upgrading

<table>
<thead>
<tr>
<th>Natural gas from natural gas field</th>
<th>I/O</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Input</td>
<td>MJ/MJ</td>
<td>1.024</td>
<td></td>
</tr>
<tr>
<td>Output</td>
<td>MJ</td>
<td>1.000</td>
<td></td>
</tr>
<tr>
<td>Emissions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO\textsubscript{2}</td>
<td>g/MJ</td>
<td>1.65</td>
<td></td>
</tr>
<tr>
<td>CH\textsubscript{4}</td>
<td>g/MJ</td>
<td>0.083</td>
<td></td>
</tr>
<tr>
<td>N\textsubscript{2}O</td>
<td>g/MJ</td>
<td>0.000</td>
<td></td>
</tr>
<tr>
<td>NMVOC</td>
<td>g/MJ</td>
<td>0.001</td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>g/MJ</td>
<td>0.005</td>
<td></td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>g/MJ</td>
<td>0.001</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>g/MJ</td>
<td>0.004</td>
<td></td>
</tr>
<tr>
<td>Dust/ particulate matter</td>
<td>g/MJ</td>
<td>0.000</td>
<td></td>
</tr>
</tbody>
</table>

The energy input addresses the lower heating value of the delivered natural gas, i.e. the energy input is inversely proportional to the energy conversion efficiency. The upgraded natural gas is transported via pipeline over a distance of 4000 km from the natural gas field to the EU.

Natural gas transport via pipeline over the distance of 4000 km requires mechanical work of approx. 0.36 MJ/tkm [JEC 2013]. The lower heating value of natural gas amounts to approx. 50 MJ/kg. Natural gas losses due to leakage along the transport route were estimated after [Wuppertal 2004] and [Wuppertal 2008].

The mechanical work for natural gas transport in pipelines is carried out by natural gas-fuelled gas turbines. The energy conversion efficiency of the gas turbine was estimated at
approx. 32%. The energy demand and emissions from the gas turbine were adopted from [GEMIS 2011].

Following [JEC 2013], the average distribution distance for natural gas via the high-pressure grid was 500 km. The average distance for local natural gas distribution via the pipeline grid was 10 km. Methane slip during natural gas distribution via high-pressure grid amounts to approx. 0.0006% per 100 km according to [GEMIS 2002]. The mechanical work required for recompression amounts to approx. 0.003 MJ/MJ natural gas. The energy conversion efficiency for the supply of mechanical work via gas turbine was adapted to 33% for the time horizon from 2020. The pressure of the local natural gas grid connecting the CNG refuelling stations usually amounts to about 0.5 MPa.

The electricity consumption of regular CNG refuelling stations typically amounts to 0.024 MJ/MJ CNG. The required electricity is supplied by the electricity grid (electricity mix Germany 2030, 0.4 kV grid).

The costs for natural gas, including transport to the EU yet independent of distribution, were derived from the crude oil price. Following [JEC 2007], the natural gas price was assumed to amount to 80% of the crude oil price.

The costs for natural gas transport and distribution among the CNG refuelling stations come to about 1.8 €/GJ based on data from [Moosbach 2011]. In addition, the costs for the natural gas refuelling station need to be considered (Table 13). Costs were specified by the manufacturers ([m-tec 2002], [Schwelm 2002]).

**Table 13: Technical and economic data for a typical CNG refuelling station**

<table>
<thead>
<tr>
<th></th>
<th>Today/2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of dispensers (2 filling hoses. 1 gauge)</td>
<td>1</td>
</tr>
<tr>
<td>Fuel turnover</td>
<td>0.6 million l DE/a</td>
</tr>
<tr>
<td>Amortisation period</td>
<td>15 a</td>
</tr>
<tr>
<td>Interest rate</td>
<td>8%</td>
</tr>
<tr>
<td>Investment</td>
<td></td>
</tr>
<tr>
<td>Dispenser</td>
<td>30,500 €</td>
</tr>
<tr>
<td>CNG storage</td>
<td>50,000 €</td>
</tr>
<tr>
<td>Compressor</td>
<td>48,800 €</td>
</tr>
<tr>
<td>Building</td>
<td>20,000 €</td>
</tr>
<tr>
<td>Installation (10% of investment for components)</td>
<td>14,930 €</td>
</tr>
<tr>
<td>Total</td>
<td>164,230 €</td>
</tr>
<tr>
<td>Other expenditure</td>
<td></td>
</tr>
<tr>
<td>Maintenance and repair compressor</td>
<td>4880 /a</td>
</tr>
<tr>
<td>Recurring safety inspection*</td>
<td>1440 /a</td>
</tr>
<tr>
<td>Calibration dispenser</td>
<td>716 /a</td>
</tr>
</tbody>
</table>

*150 € per pressure tank and 5 years; DE: diesel equivalent
CNG refuelling stations operate with well-established technology. Significant cost reductions by 2030 are therefore unlikely.

**Compressed hydrogen (CGH\textsubscript{2}) from steam methane reforming on-site at the refuelling station**

This pathway explores the supply of compressed hydrogen (CGH\textsubscript{2}) via steam methane reforming on-site at the refuelling station. Alternatively, hydrogen could be delivered in CGH\textsubscript{2} pressure tanks from centralised steam methane reforming facilities (e.g. crude oil refineries). Very large hydrogen quantities, e.g. at motorway refuelling stations, would require frequent delivery of fresh supplies (up to several times a day), particularly if HDVs also operated with hydrogen. Large-scale refuelling stations are further located at service areas off the main motorway (Autob\text{"o}fe). In these cases of large-scale demand, on-site production at the refuelling station was assumed.

The assumptions were the same as for pathway ‘GPCH1b’ in [JEC 2013]. The supply of natural gas follows the assumptions made for CNG above. The production of hydrogen via steam methane reforming is carried out on-site at the refuelling station. For the operation of the reforming plant, the natural gas has to be compressed from 0.5 MPa to 1.6 MPa. The electricity demand for compression amounts to 0.006 MJ/MJ natural gas. The technical and economic data applied in this study are based on a quote for a steam reforming plant from Haldor Topsoe in 1998. Table 14 illustrates energy flows and emissions from the production of hydrogen via steam methane reforming on-site at the refuelling station.

**Table 14: Energy flows and emissions from hydrogen production via steam methane reforming**

<table>
<thead>
<tr>
<th>I/O</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Natural gas</strong></td>
<td>Input</td>
<td>MJ/MJ</td>
</tr>
<tr>
<td><strong>Electricity</strong></td>
<td>Input</td>
<td>MJ/MJ</td>
</tr>
<tr>
<td><strong>Hydrogen</strong></td>
<td>Output</td>
<td>MJ</td>
</tr>
<tr>
<td><strong>Emissions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO\textsubscript{2}</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>CH\textsubscript{4}</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>N\textsubscript{2}O</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>NMVOC</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>NO\textsubscript{x}</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>CO</td>
<td>-</td>
<td>g/MJ</td>
</tr>
<tr>
<td>Dust/ particulate matter</td>
<td>-</td>
<td>g/MJ</td>
</tr>
</tbody>
</table>
The investment for the steam reforming plant with a hydrogen output capacity of 560 Nm³ per hour is expected to amount to about 2.2 million € [Haldor Topsoe 1998]. Costs for maintenance and repair are quoted at 1% per annum of the original investment.

The steam methane reformer supplies hydrogen at a pressure of 1.5 MPa. The hydrogen produced is compressed to 30 MPa and stored in bundles of cylinders or tanks. For the filling of high-pressure hydrogen buffer storage and vehicles, the hydrogen is compressed to 45 MPa (for HDVs and buses) or 88 MPA (for passenger cars). In this context, temperature increases during rapid refuelling have to be taken into account to ensure a pressure level of 70 MPa at 15°C in a fully fuelled vehicle tank.

The electricity consumption of the hydrogen refuelling station including hydrogen compression and pre-cooling amounts to about 0.093 MJ/MJ hydrogen for the refuelling of passenger cars, or 0.081 MJ/MJ hydrogen for the refuelling of HDVs and buses. The electricity is supplied via the electricity grid (electricity mix Germany 2030, 0.4 kV grid).

Figure 21: General structure of a CGH₂ refuelling station

For the combination of hydrogen production on-site via steam methane reforming, the stationary hydrogen storage at the refuelling station was assumed to equal 40% of the average daily turnover. The economic input data for the CGH₂ refuelling station (see Table 15) were derived from manufacturer data ([Linde 2000], [Linde 2001] and [Linde 2005]). For 2030, learning curves allowing cost reductions for the different components were assumed.
Table 15: Technical and economic data for a CGH₂ refuelling station (in combination with on-site steam methane reforming)

<table>
<thead>
<tr>
<th>For vehicles with pressure level</th>
<th>Today</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>35 MPa</td>
<td>70 MPa</td>
</tr>
<tr>
<td>Number of dispensers</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Fuel turnover</td>
<td>0.4 million l</td>
<td>0.4 million l</td>
</tr>
<tr>
<td>(120 t H₂/a. 329 kg H₂/d)</td>
<td>DE/a</td>
<td>DE/a</td>
</tr>
<tr>
<td>Amortisation period</td>
<td>15 a</td>
<td>15 a</td>
</tr>
<tr>
<td>Interest rate</td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td>Investment (€)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>H₂ storage (30 MPa)</td>
<td>84,640</td>
<td>84,640</td>
</tr>
<tr>
<td>H₂ buffer storage</td>
<td>5750</td>
<td>16,714</td>
</tr>
<tr>
<td>Compressor (primary)</td>
<td>124,342</td>
<td>124,342</td>
</tr>
<tr>
<td>Compressor (booster)</td>
<td>225,739</td>
<td>327,466</td>
</tr>
<tr>
<td>Pre-cooling</td>
<td>130,000</td>
<td>130,000</td>
</tr>
<tr>
<td>Dispenser, software, piping</td>
<td>92,299</td>
<td>129,795</td>
</tr>
<tr>
<td>Safety inspection</td>
<td>12,650</td>
<td>12,650</td>
</tr>
<tr>
<td>Installation</td>
<td>6353</td>
<td>6353</td>
</tr>
<tr>
<td>Total</td>
<td>681,773</td>
<td>831,960</td>
</tr>
<tr>
<td>Other expenditure (€/a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recurring safety inspection*</td>
<td>2880</td>
<td>2880</td>
</tr>
<tr>
<td>Calibration dispenser</td>
<td>716</td>
<td>716</td>
</tr>
<tr>
<td>Maintenance and repair compres-</td>
<td>19,206</td>
<td>22,258</td>
</tr>
<tr>
<td>sors</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*150 € per pressure tank and 5 years; DE: diesel equivalent

Compressed RE methane from renewable electricity via electrolysis and methanation

In this pathway, renewable methane is produced from hydrogen via water electrolysis with electricity from renewable energy sources and subsequent methanation with CO₂.

Electricity costs were assumed to amount to 8.5 cent/kWh plus grid use fees and grid losses. The equivalent full load period of the electrolysis and methanation plant was 4000 hours. In total, this comes to 13.1 cent/kWh for the PtG plant. The PtG plant is connected to the medium-voltage grid.

Hydrogen production via water electrolysis has been carried out for about 100 years. The first major electrolysis facility was built by Norsk Hydro in Norway in 1927. Today, potassium hydroxide solution or proton exchange membranes (PEMs) are applied as electrolytes. Alkaline electrolysis is still the most common technology today. Siemens is currently developing PEM electrolysers in the multi-MW range [Waidhas 2011].

The total electricity demand including all auxiliary power units (rectifier, pumps, compressors, controllers, gas upgrading if applicable) of current electrolysers ranges between 4.3 and
5.2 kWh/Nm³ hydrogen. In reference to the lower heating value of the hydrogen produced, this results in an energy conversion efficiency between 57% and 70%. For this study, an electrolysis electricity consumption of 4.5 kWh/Nm³ hydrogen was assumed. Hydrogen is supplied with a pressure of 3 MPa (pressure electrolysis).

The investment for the electrolyser was assumed to come to 700 €/kWₑ in 2030. Costs for maintenance and repair were estimated with 32 €/kWₑ per annum assuming 8760 operation hours per annum. An equivalent full load period of 4000 h per annum results in annual costs of about 15 €/kWₑ.

The next step is methanation with CO₂. The following reaction describes the conversion of hydrogen to methane:

\[
4 \text{ H}_2 + \text{CO}_2 \Rightarrow \text{CH}_4 + 2 \text{H}_2\text{O (gaseous)} \quad \Delta H = -165 \text{ kJ}
\]

This is an exothermic reaction. Catalytic methanation is carried out at temperatures between 200 and 400°C. Catalysts include Ni or Ru, Rh, Pt, Fe, and Co [Lehner 2012]. Catalytic methanation is carried out at 0.5 MPa pressure.

[Breyer et al 2011] specify an investment of 400 €/kW for methanation referring to the electrical power consumption of the electrolyser producing hydrogen for methanation. [Breyer et al 2011] further assume an electrolysis electricity consumption of 1.65 kWh in reference to the lower heating value of methane. For the methanation plant, this results in an investment of approx. 660 €/kW methane in reference to the lower heating value (LHV). Costs for maintenance and repair are reported to amount to 2% of the investment.

CO₂ extraction from ambient air is carried out in a scrubbing process with potassium hydroxide solution (KOH) and subsequent regeneration of the scrubbing agent via electrodialysis. The electricity consumption for the process comes to 8.2 MJ/kg CO₂ [Sterner 2009]. The CO₂ thus produced is subsequently compressed from ambient pressure to 0.5 MPa.

The investment for CO₂ extraction from ambient air after [Breyer et al 2011] comes to 500 €/kW. Again, this estimate refers to the electrical power consumption of the electrolyser producing hydrogen for methanation. Considering the electricity consumption reported in [Breyer et al 2011], the resulting costs amount to 825 €/kW methane.

CO₂ extraction from flue gas is carried out in a scrubbing process with monoethanolamine (MEA). Regeneration of the scrubbing agent and extraction of CO₂ consumes 4.3 MJ of heat [Specht et al 1995]. In addition, 0.0334 kWh of electricity are required for the operation of pumps and fans [Socolow et al 2011]. In a subsequent step, the resulting CO₂ is compressed to 0.5 MPa from ambient pressure. The heat demand is partly covered by heat generated during the methanation reaction.
The investment for CO₂ extraction from flue gas was derived from [Socolow et al 2011] and amounts to approx. 200 €/kW methane.

For methanation with CO₂ from a biogas plant, it was assumed that the biogas plant was already equipped with a biogas upgrading facility carrying out purification of methane and feed-in into the gas grid. The electricity demand arises from CO₂ compression from ambient pressure to the pressure level if 0.5 MPa required for the methanation plant.

Table 16 illustrates energy and material flows for the production of methane from H₂ and CO₂.

**Table 16: Energy and material flows for the production of methane from H₂ and CO₂**

<table>
<thead>
<tr>
<th></th>
<th>I/O</th>
<th>Unit</th>
<th>CO₂ from air</th>
<th>CO₂ from flue gas</th>
<th>CO₂ from BGU</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂ Input</td>
<td>MJ/MJ</td>
<td>1.200</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ Input</td>
<td>kg/MJ</td>
<td>0.055</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity for CO₂ supply Input</td>
<td>MJ/MJ</td>
<td>0.4590</td>
<td>0.0098</td>
<td>0.0080</td>
<td></td>
</tr>
<tr>
<td>Heat for CO₂ supply Input</td>
<td>MJ/MJ</td>
<td>-</td>
<td>0.2365</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>CH₄ Output</td>
<td>MJ</td>
<td>1.000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat Output</td>
<td>MJ/MJ</td>
<td>0.200</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

BGU: biogas upgrading

The methane produced is transported to refuelling stations via the natural gas grid. The electricity consumption of CNG refuelling stations typically amounts to 0.024 MJ/MJ CNG. The required electricity is supplied by the electricity grid (electricity mix Germany 2030, 0.4 kV grid).

**Compressed hydrogen (CGH₂) from renewable electricity via on-site electrolysis at the refuelling station**

In this pathway, hydrogen is produced via water electrolysis with electricity from renewable energy sources on-site at the hydrogen refuelling station.

Electricity costs were estimated at 8.5 cent/kWh plus costs for grid use fees and grid losses. The equivalent full load period of the electrolyser facility is specified at 4000 h per annum. The resulting specific costs amount to 13.1 cent/kWh for the CGH₂ refuelling station with electrolyser.

The electrolysis electricity consumption is assumed to come to 4.5 kWh/Nm³ hydrogen, resulting in an energy conversion efficiency of 67% in reference to the lower heating value. Hydrogen is supplied at a pressure of 3 MPa (pressure electrolysis).
The electrolyser investment in 2030 is assumed to amount to approx. 700 €/kW$_{el}$. Costs for maintenance and repair come to 32 €/kW$_{el}$ per annum assuming 8760 h in operation annually. With an equivalent full load period of 4000 h per annum, the resulting costs amount to 15 €/kW$_{el}$ per annum.

The produced hydrogen is compressed to 30 MPa and stored in bundled cylinders or tanks. For the filling of high-pressure hydrogen buffer storage and vehicles, the hydrogen is compressed to 45 MPa (for HDVs and buses) or 88 MPa (for passenger cars). Thus, temperature increases during rapid refuelling are taken into account to ensure a pressure level of 70 MPa at 15°C in a fully fuelled vehicle tank.

The electricity consumption of the hydrogen refuelling station including hydrogen compression and pre-cooling amounts to about 0.079 MJ/MJ hydrogen for the refuelling of passenger cars, or 0.067 MJ/MJ hydrogen for the refuelling of HDVs and buses. The electricity for the refuelling station is also supplied from renewable electricity sources. The hydrogen refuelling station with associated electrolysis facility is connected to the medium-voltage grid (electrical power rating > 1 MW).

For the combination of hydrogen production on-site via electrolysis, the stationary hydrogen storage at the refuelling station was assumed to equal 200% of the average daily turnover. The economic input data for the CGH$_2$ refuelling station (see Table 17) were derived from manufacturer data ([Linde 2000], [Linde 2001] and [Linde 2005]). For 2030, learning curves allowing cost reductions for the different components were assumed.
Table 17: Technical and economic data for a typical CGH₂ refuelling station (in combination with on-site electrolysis)

<table>
<thead>
<tr>
<th></th>
<th>Today</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>For vehicles with pressure level</strong></td>
<td>35 MPa</td>
<td>70 MPa</td>
</tr>
<tr>
<td><strong>Number of dispensers</strong></td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td><strong>Fuel turnover</strong> (120 t H₂/a, 329 kg H₂/d)</td>
<td>0.4 million l DE/a</td>
<td>0.4 million l DE/a</td>
</tr>
<tr>
<td><strong>Amortisation period</strong></td>
<td>15 a</td>
<td>15 a</td>
</tr>
<tr>
<td><strong>Interest rate</strong></td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Investment (€)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H₂ storage (30 MPa)</td>
<td>402,040</td>
<td>402,040</td>
</tr>
<tr>
<td>H₂ buffer storage</td>
<td>5750</td>
<td>16,714</td>
</tr>
<tr>
<td>Compressor (primary)</td>
<td>165,152</td>
<td>165,152</td>
</tr>
<tr>
<td>Compressor (booster)</td>
<td>225,739</td>
<td>327,466</td>
</tr>
<tr>
<td>Pre-cooling</td>
<td>130,000</td>
<td>130,000</td>
</tr>
<tr>
<td>Dispenser, software, piping</td>
<td>92,299</td>
<td>129,795</td>
</tr>
<tr>
<td>Safety inspection</td>
<td>12,650</td>
<td>12,650</td>
</tr>
<tr>
<td>Installation</td>
<td>6353</td>
<td>6353</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,039,983</td>
<td>1,190,169</td>
</tr>
<tr>
<td><strong>Other expenditure (€/a)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recurring safety inspection*</td>
<td>13,680</td>
<td>13,680</td>
</tr>
<tr>
<td>Calibration dispenser</td>
<td>716</td>
<td>716</td>
</tr>
<tr>
<td>Maintenance and repair compressors</td>
<td>23,287</td>
<td>26,339</td>
</tr>
</tbody>
</table>

*150 € per pressure tank and 5 years; DE: diesel equivalent

**Compressed hydrogen (CGH₂) from renewable electricity via centralised electrolysis at a salt cavern and hydrogen distribution via pipeline**

In this case, hydrogen is produced centrally in close proximity to a salt cavern and stored in the cavern. Hydrogen extracted from the cavern is distributed to refuelling stations via a pipeline grid.

Electricity costs were estimated at 8.5 cent/kWh plus costs for grid use fees and grid losses. The equivalent full load period of the electrolyser facility is specified at 4000 h per annum. The resulting costs amount to 11.2 cent/kWh for the electrolyser.

The electrolysis electricity consumption is assumed to come to 4.5 kWh/Nm³ hydrogen, resulting in an energy conversion efficiency of 67% in reference to the lower heating value. Hydrogen is supplied at a pressure of 3 MPa (pressure electrolysis).

The electrolyser investment in 2030 was assumed to amount to approx. 700 €/kW_el. Costs for maintenance and repair come to 32 €/kW_el per annum assuming 8760 h in operation annual-
ly. With an equivalent full load period of 4000 h per annum, the resulting costs amount to 15 €/kW\(_{el}\) per annum.

The hydrogen produced is initially compressed to the maximum pressure level of the above-ground buffer storage (6.4 MPa). According to [NIP 2013], the buffer storage is evacuated to a minimal pressure of 2 MPa. For the filling of the salt cavern, the hydrogen is compressed to 18 MPa.

Technical and economic data for the salt cavern were derived from data reported in [NIP 2013]. Hydrogen extracted from the salt cavern requires purification. For gas purification via pressure swing adsorption, about 5% of the hydrogen is required as purge gas. This purge gas may be used for energy purposes, e.g. for utilisation in a gas engine or gas turbine (instead of simple combustion). However, these additional uses were omitted from the study. Hydrogen loss due to leakages in the salt cavern is below 0.02% per annum. Cushion gas\(^{42}\) was included for the calculations on investment.

Table 18: Technical and economic data for a typical salt cavern including facilities above ground

<table>
<thead>
<tr>
<th></th>
<th>Today / 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geometric volume</td>
<td>500,000 m(^3)</td>
</tr>
<tr>
<td>Casing shoe depth</td>
<td>1000 m</td>
</tr>
<tr>
<td>Maximum pressure</td>
<td>18 MPa</td>
</tr>
<tr>
<td>Minimum pressure</td>
<td>6 MPa</td>
</tr>
<tr>
<td>Net storage capacity</td>
<td>3733 t H(_2) (124 GWh H(_2))</td>
</tr>
<tr>
<td>Maximum mass flow</td>
<td>13,500 kg H(_2)/h</td>
</tr>
<tr>
<td>Compressor capacity</td>
<td>10,500 kg H(_2)/h</td>
</tr>
<tr>
<td>Power consumption</td>
<td>10.1 MW(_{el})</td>
</tr>
<tr>
<td>Total investment</td>
<td>106.8 Mio. €</td>
</tr>
<tr>
<td>Cavern only</td>
<td>35.6 Mio. €</td>
</tr>
<tr>
<td>Facilities above ground</td>
<td>60.2 Mio. €</td>
</tr>
<tr>
<td>Cushion gas only</td>
<td>11.1 Mio. €</td>
</tr>
<tr>
<td>H(_2) loss cavern</td>
<td>0.02%/a</td>
</tr>
<tr>
<td>H(_2) loss gas</td>
<td>5%</td>
</tr>
<tr>
<td>Number of full cycle</td>
<td>12</td>
</tr>
</tbody>
</table>

Hydrogen is distributed to refuelling stations via a hydrogen pipeline grid. The technical and economic data for this hydrogen grid are illustrated in Table 19.

\(^{42}\) Cushion gas (or base gas) is the term applied for the share of the gaseous cavern content that is necessary to maintain minimum pressure in the cavern as permanent stock. Supply costs for cushion gas are commonly allocated to the investment for the cavern and represent a major share of cavern costs.
Table 19: Technical and economic data on H$_2$ pipeline grid

<table>
<thead>
<tr>
<th></th>
<th>Today/2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length pipeline grid DN 300 mm</td>
<td>500 km (e.g. 10 pipelines of 50 km each)</td>
</tr>
<tr>
<td>Specific investment DN 300 mm</td>
<td>650 €/m</td>
</tr>
<tr>
<td>Length pipeline grid DN 100 mm</td>
<td>500 km (e.g. 100 pipelines of 5 km each)</td>
</tr>
<tr>
<td>Specific investment DN 100 mm</td>
<td>352 €/m</td>
</tr>
<tr>
<td>Investment pipeline grid total</td>
<td>501 Mio. €</td>
</tr>
<tr>
<td>H$_2$ flow rate</td>
<td>1404 GWh/a (LHV)</td>
</tr>
</tbody>
</table>

The pressure of the hydrogen delivered to refuelling stations is 2 MPa. The set-up of the hydrogen refuelling station is similar to that of the model for on-site production of hydrogen at the refuelling station. However, at 2 MPa, the pressure is lower compared to 3 MPa in the alternative model.

The electricity consumption of the hydrogen refuelling station including hydrogen compression and pre-cooling amounts to about 0.086 MJ/MJ hydrogen for the refuelling of passenger cars, or 0.074 MJ/MJ hydrogen for the refuelling of HDVs and buses. The electricity for the refuelling station is supplied via the electricity grid (electricity mix Germany 2030, 0.4 kV grid).

For the combination of hydrogen delivery via pipeline, the stationary hydrogen storage at the refuelling station was assumed to equal 40% of the average daily turnover. The economic input data for the CGH$_2$ refuelling station (see Table 20) were derived from manufacturer data ([Linde 2000], [Linde 2001] and [Linde 2005]). For 2030, learning curves allowing cost reductions for the different components were assumed.
Table 20: Technical and economic data for a typical CGH₂ refuelling station (in combination with H₂ delivery via pipeline)

<table>
<thead>
<tr>
<th></th>
<th>Today</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>For vehicles with pressure level</td>
<td>35 MPa</td>
<td>70 MPa</td>
</tr>
<tr>
<td>Number of dispensers</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Fuel turnover (120 t H₂/a, 329 kg H₂/d)</td>
<td>0.4 million l DE/a</td>
<td>0.4 million l DE/a</td>
</tr>
<tr>
<td>Amortisation period</td>
<td>15 a</td>
<td>15 a</td>
</tr>
<tr>
<td>Interest rate</td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td>Investment (€)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>H₂ storage (30 MPa)</td>
<td>84,640</td>
<td>84,640</td>
</tr>
<tr>
<td>H₂ buffer storage</td>
<td>5750</td>
<td>16,714</td>
</tr>
<tr>
<td>Compressor (primary)</td>
<td>124,342</td>
<td>124,342</td>
</tr>
<tr>
<td>Compressor (booster)</td>
<td>225,739</td>
<td>327,466</td>
</tr>
<tr>
<td>Pre-cooling</td>
<td>130,000</td>
<td>130,000</td>
</tr>
<tr>
<td>Dispenser, software, piping</td>
<td>92,299</td>
<td>129,795</td>
</tr>
<tr>
<td>Safety inspection</td>
<td>12,650</td>
<td>12,650</td>
</tr>
<tr>
<td>Installation</td>
<td>6353</td>
<td>6353</td>
</tr>
<tr>
<td>Total</td>
<td>681,773</td>
<td>831,960</td>
</tr>
<tr>
<td>Other expenditure (€/a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recurring safety inspection*</td>
<td>2880</td>
<td>2880</td>
</tr>
<tr>
<td>Calibration dispenser</td>
<td>716</td>
<td>716</td>
</tr>
<tr>
<td>Maintenance and repair compressors</td>
<td>19,206</td>
<td>22,258</td>
</tr>
</tbody>
</table>

*150 € per pressure tank and 5 years; DE: diesel equivalent
Appendix II: Scenario assumptions

Assumptions scenario 1: ‘CNG / LNG without renewable Power-to-Methane’

- Focus on efficiency increases for conventional engines,
- For cost and availability reasons, the focus is shifted from diesel and petrol towards natural gas engines, particularly for the rapidly growing segment of heavy-duty vehicles. For HDVs, the share of transport performance for CNG/LNG engines is already at about 20% in 2030, with a projected growth to 80% by 2050.
- The market launch of battery electric mobility for passenger cars is assumed to proceed according to current medium projections\textsuperscript{43}. However, new registrations of BEVs are assumed to stagnate after 2030; thus the scenario reflects rather low user acceptance of these vehicles.
- The LNG share in inland navigation is expected to increase; in 2050, half of the final energy demand will be covered with LNG.
- **No renewable Power-to-Methane**; the low number of FCEVs are supplied with renewable Power-to-Hydrogen.
- This scenario corresponds to the scenario ‘combustion engines’ in the MFS study ‘Renewable Energies in Transport’.

Assumptions scenario 2: ‘CNG / LNG with renewable Power-to-Methane’

- Similar to scenario 1, however, CNG or LNG is increasingly produced via PtG. **In 2050, the demand for CNG and LNG is supplied entirely via renewable PtG.**
- Departing from scenario 1, from 2030 no petrol or diesel PHEVs are registered anymore, only CNG PHEVs that may be operated with RE PtCH\textsubscript{4}. At present, the utilisation of CNG engines in PHEVs appears promising with regard to weight and costs.

Assumptions scenario 3: ‘Renewable Power-to-Methane and FCEVs’

- For passenger cars, increase of market penetration with BEVs continues after 2030. Moreover, successful market launch of FCEVs.
- For HDVs, fuel cells start to attract a share of the market from 2030, thus curbing the market performance of CNG/LNG to 2050 in comparison with scenarios 1 and 2.

\textsuperscript{43} Scenario ‘mittlerer Hochlauf’ from NPE 2013 (to the year 2020) or scenario ‘Trend’ from DLR 2013 (to the year 2030)
Appendix III: Detailed descriptions of demonstration projects

Activities in Germany

Synthetic methane

AUDI Werlte – Werlte, Germany

**Status:** In operation since June 2013.

**Participants:** AUDI AG, ETOGAS, EWE AG, MT BioMethan GmbH, ZSW, IWES

**Characteristics:** 6 MW entire plant, methanation, CO₂ from biogas, methane feed-in into the natural gas grid.

**Description:** The facility with alkaline electrolyser and waste heat utilisation produces 1300 Nm³/h hydrogen (H₂) or 300 Nm³/h synthetic methane (CH₄), respectively. The CO₂ is supplied by a biogas plant. Annual methane production is going to total at 3 million Nm³. The plant is designed to allow environmentally friendly refuelling of methane. The pilot plant at ZSW Stuttgart served as a model for the methanation plant.

CO₂ extraction from biogas is carried out via scrubbing with monoethanolamine (MEA). Regeneration of the scrubbing agent is carried out applying heat from the exothermic methanation process. Assuming an electrical power consumption of 6300 kW including all auxiliary power units (e.g. rectifier, pumps, fans, controllers) and 320 Nm³ CO₂ after [Schoeber 2012], the methane produced amounts to 3184 kW (calculated from CO₂ consumption in chemical equation) in reference to the lower heating value. In consequence, the total energy conversion efficiency is 51%. The 350 Nm³ product gas per hour reported in [Schoeber 2013] are likely to include impurities. Under the assumption that the reported 350 Nm³ refer to purified methane, the total energy conversion efficiency improves to 55%. This result is close to the 54% cited by AUDI. [Rieke 2013] reports an electricity consumption of 27,600 MWh for the production of 1000 t of methane (13,890 MWh in reference to the lower heating value). In consequence, the energy conversion efficiency is about 50%.

CO₂RRECT – Niederaußem, Germany

**Status:** In operation since February 2013.

**Participants:** Bayer Technology Services BTS, RWE Power, Siemens, Bayer Material Science BMS, et al.
Characteristics: 300 kW electrolyser, methanation, CO₂ from flue gas from a lignite-fired power plant

Description: CO₂RECT = CO₂ Reaction using Renewable Energies and Catalytic Technologies. In this research facility at RWE Power, a number of different catalysts for methanation are tested. The electrolyser was manufactured by Siemens and is tested for flexibility. The production of methanol is tested as well. The hydrogen output amounts to 50 Nm³/h.

Figure 22: Electrolyser at power plant Niederaußem, Germany (Source: RWE)

Green electricity storage Wunsiedel – Wunsiedel, Germany

Status: Proposed.

Participants: Stadtwerke Wunsiedel (municipal utility)

Characteristics: Methanation with CO₂ from industrial production.

Description: The project will not be realised before 2015. The budget total is 20 million €, governmental funding is 4.3 million €. After funding was approved in July 2013, detailed planning is now under way (status May 2014). The goal is hydrogen production from excess wind and solar energy, with subsequent methanation applying CO₂ from local industry.

Storage test for the Energy Transition – Morbach, Germany


Participants: ETOGAS, juwi technologies GmbH, ZSW, Reiner Lemoine Institut RLI, RWE Deutschland AG

Characteristics: 25 kW pilot plant, theoretical studies.

Description: This research project aims to investigate the potential contributions of PtG to the Energy Transition (Energiewende) on a small scale. Focusing on a model region, the
requirements of dedicated renewable supply with PtG plants will be explored. The project comprises estimates for potentials, simulations as well as the construction of a pilot plant and its operation under real-world conditions. The project is scheduled to commence in January 2014 for a duration of two years with funding from the German Ministry for the Environment.

**Compact biogas plant ‘EUCOlino’ with in-situ methanation – Schwandorf, Germany**

**Status:** In operation since November 2012.

**Participants:** MicrobEnergie GmbH (affiliate of Viessmann)

**Characteristics:** 108 kW, methanation.

**Description:** The plant produces 21 Nm³/h of hydrogen or 5 Nm³/h of synthetic methane. Biogas is used as a CO₂ source. In contrast to catalytic methanation (e.g. the project in Werlte), here methanation is achieved biologically with microorganisms in-situ in the fermenter of the biogas plant. Thus, the methane content of the biogas stream at the exit of the fermenter is increased. The synthetic methane is used for electricity production along with biogas.

![Compact biogas plant ‘EUCOlino’ in Schwandorf](source: MicrobEnergy GmbH)

**Figure 23:** Compact biogas plant ‘EUCOlino’ in Schwandorf
(Source: MicrobEnergy GmbH)

**Viessmann research facility – Allendorf, Germany (with in-situ methanation)**

**Status:** Proposed.

**Participants:** Viessmann

**Characteristics:** Biogas plant with associated PtG plant.

**Description:** In August 2013, Viessmann opened a new biogas plant at the company headquarters in Allendorf, Germany. There are plans to extend the biogas plant with a PtG plant. Hydrogen produced with an electrolyser is methanated with the upgraded biogas and fed into
the natural gas grid. Methanation is carried out biologically in situ in the fermenter of the biogas plant, similar to the MicrobEnergy plant in Schwandorf, Germany.

ETOGAS ZSW pilot plant – Stuttgart, Germany

**Status:** In operation since October 2012.

**Participants:** ZSW, IWES, ETOGAS, Hydrogenics

**Characteristics:** 250 kW entire plant, methanation, methane feed-in into the natural gas grid.

**Description:** At the ZSW, PtG plants with different configurations have been tested for a number of years. An alkaline pressure electrolyser was used in the past. The novel system works with an alkaline electrolyser, model HySTAT 60 by Hydrogenics, and produces 60 Nm$^3$ of hydrogen per hour fed into a subsequent methanation with a maximum output of 15 Nm$^3$ methane per hour. Daily methane production is reported to come to 300 Nm$^3$, or an average of 12.5 Nm$^3$ per hour. The electricity consumption of the electrolyser according to the manufacturer comes to 5.2 kWh/Nm$^3$ hydrogen. The electrical power consumption at full electrolyser load would thus amount to 312 kW.

[Etogas 2/2013] reports a maximum electrical power consumption of 280 kW direct current (DC) with a hydrogen output of 65 Nm$^3$ hydrogen per hour (including the rectifier, the electrical power consumption would be higher).

[ZSW 2012] reports an electrical power consumption of 295 kW DC given an output of 65 Nm$^3$ hydrogen per hour. This hydrogen is converted into 15 Nm$^3$ methane per hour in the subsequent methanation plant. Both [Etogas 2/2013] and [ZSW 2012] report their data assuming a current density of 430 mA/cm$^2$, i.e. equal load on the electrolyser. Assuming an energy conversion efficiency of 95% for the rectifier, the resulting electrical power consumption amounts to approx. 311 kW. This is consistent with the 312 kW reported above from the technical data published by Hydrogenics. The combination of an electrical power consumption of 312 kW and a methane output of 15 Nm$^3$/h result in an energy conversion efficiency of about 48%.

The output of 12.5 Nm$^3$ CH$_4$ per hour are probably achieved with a low electrolyser load. The total energy conversion efficiency, given an electrical power consumption of 250 kW and a methane output of 12.5 Nm$^3$/h, amounts to about 50%. In all likelihood, the reported 250 kW$_{el}$ refer to the electrical power consumption after the rectifier (DC) and not at full electrolyser load.

Waste heat is utilised within the institute. In August 2013, the produced gas reached natural gas standards (high methane content).
Agricultural Centre at the Eichhof – Bad Hersfeld, Germany

**Status:** In operation since January 2012.

**Participants:** Fraunhofer IWES, ZSW, ETOGAS

**Characteristics:** 25 kW electrolyser, methanation.

**Description:** In periods of excess electricity, hydrogen will be produced for subsequent methanation with CO$_2$ from a biogas plant. In Bad Hersfeld (Germany), CO$_2$ is not extracted from the biogas stream. Instead, the biogas stream including CO$_2$ is fed into the methanation plant (‘direct methanation’). Separate CO$_2$ extraction in a biogas upgrading facility is not required. Methanation of the CO$_2$ increases the methane content of the gas stream to over 90%. If the gas is stored locally (e.g. in storage balloons) and elaborate, cost-intensive conversion measures are not required, this process may be suitable for smaller biogas plant from 250 kW$_{el}$ (equal to about 750 kW methane) [IWES 2012], [IWES 2013], [Etogas 1/2013]. Methane thus produced is reconverted to electricity like biogas. The output is 6 Nm$^3$/h H$_2$ or 1.5 Nm$^3$/h methane, respectively [DVGW 2013].

Direct hydrogen application

**ENERTRAG Hybridkraftwerk – Prenzlau, Germany**

**Status:** In operation since October 2011.

**Participants:** Total, Vattenfall, Deutsche Bahn

**Characteristics:** 500 kW electrolyser, on-site reconversion, hydrogen storage, hydrogen feed-in into the natural gas grid and filling of trailers for delivery to hydrogen refuelling stations.
Description: The hybrid power plant built here was designed for need-based production of electricity, fuel and heat from renewable sources: wind energy + biogas + hydrogen production + storage + refuelling station + need-based electricity production from CHP plant + control energy. Wind energy is generated by three wind turbines of the type Enercon E-82 with a respective nominal capacity of 2.3 MW. The turbines are directly connected to the electrolysis plant via a medium-voltage cable. This medium-voltage cable is further connected to the medium-voltage grid that directly feeds into the 220 kV extra high-voltage grid of the 50Hertz Transmission GmbH via the electrical substation Bertikow, Germany. The energy conversion efficiency for hydrogen production ranges between 75% and 82%. Arising heat may also be used, thus more than 90% of the energy may be utilised. The use of hydrogen in fuel cell cars doubles the energy conversion efficiency to 50% in comparison with Otto engines. In consequence, the energy conversion efficiency of the fuel pathway amounts to 45%. Reconversion in the CHP plant is associated with 38% energy conversion efficiency, plus 40% heat utilisation. Thus, an overall energy conversion efficiency of about 80% may be achieved.

At nominal capacity, the (alkaline) electrolyser produces 120 Nm$^3$/h hydrogen and 60 Nm$^3$/h oxygen. Two compressors compress the hydrogen to a pressure of 4.2 MPa for subsequent transfer into three stationary gas storage depots with a total capacity of 1150 kg (at 4.2 MPa). The hybrid power plant supplies all three energy sectors (electricity, fuel, heat). In consequence, the overall energy conversion efficiency across all three sectors should be considered. It may reach up to 65% depending on the way of operation.

The investment for the hydrogen system amounts to about 10 million €. The total investment for all plant components installed during the project exceeds 21 million €. Funding for the pilot project was obtained through the initiative for the development of Eastern Germany (Gemeinschaftsaufgabe Ost) and through the 7th framework plan for R&D of the German Federal State of Brandenburg. ENERTRAG supplied more than 2 million € of own funds for research and development of the hybrid power plant. TOTAL, Vattenfall and the Deutsche Bahn AG contributed 500,000 € each.
Figure 25: ENERTRAG PtG plant in Prenzlau, Germany (Source: ENERTRAG)

E.ON Falkenhagen – Falkenhagen, Germany

Status: Completed. Opening 28 August 2013

Participants: E.ON, Hydrogenics, Swissgas AG

Characteristics: 2 MW electrolyser, hydrogen feed-in into the natural gas grid

Description: The plant includes six PEM electrolysers of the type HySTAT 60 Outdoor. Hydrogenics is responsible for maintenance and operation of the plant during the first five years. The trial period started in June 2013. The plant will be able to store 30 MWh of energy over 24 hours to take the load off the electricity grid in critical periods. One container comprises two compressors for the compression of hydrogen to 5.5 MPa and subsequent feed-in into the natural gas grid. During the trial period, an initial volume of 160 Nm³/h of hydrogen was produced. Standard operation is expected to produce 360 Nm³/h.

Six electrolyser units with a respective electrical power consumption of 330 kW are combined to a total output of 360 Nm³ hydrogen per hour (60 Nm³/h per electrolyser unit) [Steiner et al 2012]. This is about equal to 1080 kW hydrogen in reference to the lower heating value. The resulting energy conversion efficiency in reference to the lower heating value is approx. 55%.

[Bihler 2012] estimates a total investment of 5 million €.
E.ON Hanse Hamburg – Hamburg Reitbrook, Germany

**Status:** Under construction, to be completed by the end of 2014.

**Participants:** E.ON Hanse, City of Hamburg, Hydrogenics, SolviCore, DLR, ISE

**Characteristics:** 1 MW electrolyser, hydrogen feed-in into the natural gas grid.

**Description:** The Hydrogenics electrolyser is the world’s largest single PEM electrolyser. The three-year model project has an overall budget of 13.5 million € and an investment volume of 5 million €. Hydrogen output is expected to be 265 Nm³/h.

Given an electrical power consumption of 1000 kW and a hydrogen production capacity of 265 Nm³/h, the resulting energy conversion efficiency would come to 79.8% in reference to the lower heating value (94% in reference to the upper heating value). This efficiency is extremely high. In all likelihood, the 1000 kW refer to the power consumption excluding any auxiliary power units, or the value was rounded down (e.g. from 1.2 MW).

Thüga demonstration plant – Frankfurt a.M., Germany

**Status:** Completed. Opening 07 May 2014.

**Participants:** Thüga (Projektleiter), ITM Power, badenova AG & Co. KG, Erdgas Mittelsachsen GmbH, Energieversorgung Mittelrhein GmbH, erdgas schwaben gmbh, ESWE Versorgungs AG, Gasversorgung Westerwald GmbH, Mainova Aktiengesellschaft, Stadtwerke Ansbach GmbH (municipal utility), Stadtwerke Bad Hersfeld GmbH (municipal utility), Thüga Energienetze GmbH, WEMAG AG, e-rp GmbH

**Characteristics:** 320 kW, hydrogen feed-in into the natural gas grid.

**Description:** The PEM electrolyser was supplied by ITM. Expected output is 60 Nm³/h hydrogen or 3000 Nm³/h hydrogen-enriched natural gas. The demonstration stage is scheduled to run for three years. Upon completion, the installation of a methanation facility is intended.

Given the electrical power consumption of 320 kW and the expected hydrogen production of 180 kW in reference the lower heating value, the energy conversion efficiency comes to 56% in reference to the lower heating value.

Wind Park RH2-WKA – Grapzow, Germany

**Status:** Trial period under way since December 2012, Opening 19 September 2013.

**Participants:** WIND-WASSERSTOFF-projekt GmbH & Co KG, WIND-projekt Ingenieur-und Projektentwicklungsgesellschaft mbH, Hydrogenics

**Characteristics:** 1 MW electrolyser, on-site storage, reconversion.
Description: The wind-hydrogen system stores fluctuating wind energy of 28 wind turbines independent of time and is capable of subsequent need-based feed-in in the form of electricity. Reconversion is achieved with a CHP plant with 250 kW_{el} / 400 kW_{th}. Hydrogen output may reach 210 Nm³/h. During the trial period, the energy system was set up to cover its own electricity demand. In this arrangement, the wind park is the consumer that requires need-based supply with electricity. In periods of high winds, the wind turbines were self-supplying, whereas during calm periods, the integrated hydrogen plant delivered. Thus, only the wind park acted as an energy supplier to the grid. After completion of the associated electrical substation, the entire plant opened in September 2013.

H2 Herten – Herten, Germany

Status: In operation since May 2013,

Participants: Hydrogenics, Evonik, German Federal State NRW

Characteristics: 280 kW electrolyser, potential plans for hydrogen refuelling station, reconversion, hydrogen storage.

Description: The plant is equipped with a Hydrogenics HyPM-R 50 kW fuel cell system, a HySTAT 30 Indoor electrolyser with 30 Nm³/h hydrogen output and storage for 500 kg hydrogen. The expected annual output is 250 MWh electricity and about 6500 kg hydrogen for on-site demand at the Centre h2herten. The energy supply is based on the wind park Hoppenbruch. A complementary system for energy based on hydrogen was developed to supplement fluctuating wind energy. In periods of excess wind energy, hydrogen is produced. In turn, the hydrogen is used in calm periods to balance peak loads and stabilise the grid via reconversion with the fuel cell system. There is a small hydrogen refuelling station close to the facility. There are plans for the construction of a new, expanded hydrogen refuelling station on the premises.

RWE demonstration plant Ibbenbüren – Ibbenbüren, Germany

Status: Under construction, completion planned by end of 2013.

Participants: RWE, CERAM HYD

Characteristics: 100 kW electrolyser, hydrogen feed-in into the natural gas grid.

Description: In this plant, a novel PEM electrolyser is tested for optimisation. The hydrogen output is 20 Nm³/h.

Electricity stopgap – Reußenköge, Germany

Status: Under construction, completion planned by August 2013.
Participants: North-Tec Maschinenbau GmbH, GP Joule GmbH, H-TEC Systems GmbH

Characteristics: 200 kW electrolyser, on-site hydrogen storage and reconversion.

Description: This is a biogas plant that utilises excess electricity for the production of hydrogen. The hydrogen is stored and blended into the biogas to increase the heating value, thus achieving hydrogen reconversion. The maximum hydrogen output is 40 Nm³/h.

WESpe Kyritz Ruppiner Heide – Kyritz, Germany

Status: Proposed.

Participants: Enertrag, Vattenfall, Gasag, Total, Linde, Fraunhofer ISE, DLR, btu, Deutsche Umwelthilfe, DBI GTI

Characteristics: 6.7 MW plant with hydrogen cavern storage, feed-in into the natural gas grid, trailer filling and feed-in into a hydrogen pipeline.

Description: Plans are for a cross-system power plant as a concept for ‘electricity – storage – transport’. Hydrogen produced by alkaline pressure electrolysis is fed into an existing natural gas grid and stored in a cavern with a storage volume of approx. 200,000 m³. The hydrogen is intended for mobility purposes. Total investment is expected to be around 700 million €, funding amounts to 12 million €.

Energy Park Mainz – Hechtsheim, Germany

Status: Proposed for 2015.

Participants: Stadtwerke Mainz (municipal utility), Linde, Siemens, RheinMain University of Applied Sciences

Characteristics: 6 MW electrolyser, hydrogen storage, reconversion, feed-in into the natural gas grid, trailer filling.

Description: Construction is scheduled to commence in early 2014 to start operation in the spring of 2015. The investment budget is approx. 17 million €. Hydrogen will be produced with electricity from wind energy and subsequently distributed to hydrogen refuelling stations via tankers or fed into the natural gas grid. The project further explores the suitability of the produced hydrogen as a fuel for reconversion in the CHP plant of the Kraftwerke Mainz-Wiesbaden AG at Ingelheimer Aue, Germany. The three 2 MW electrolysers are manufactured by Siemens. The ionic compressor for the compression of hydrogen for storage, distribution and grid feed-in purposes is manufactured by Linde. The project is subsidised by the German Federal Ministry of Economy (BMWi).
HYPOS – Saxony-Anhalt, Germany

**Status:** Proposed.

**Participants:** Total 92 partners, among them Fraunhofer IWM, Wirtschaftsinitiative für Mitteldeutschland GmbH, Cluster Chemie/Kunststoffe Mitteldeutschland.

**Characteristics:** Industrial-scale hydrogen production for feed-in into the natural gas grid and into hydrogen pipeline for use as fuel and chemical feedstock.

**Description:** Collaboration of individual enterprises of the chemical and plastics industries chaired by the Fraunhofer Institute for Mechanics of Materials. The goal is the realisation of an industrial-scale PtG plant. In addition to feed-in into the natural gas grid, the hydrogen produced is intended for distribution to the chemical industry. The project is currently still in its infancy. Funding was approved in July 2013.

ChemCoast – Lower Elbe region, Germany

**Status:** Initial discussion.

**Participants:** ChemCoast as coordinator of the following (chemical) industry representatives: ArcelorMittal, Arge Netz, Aurubis, Bayer Material Science, BeBa Energie, DOW, E.ON Gas Storage, Hamburg Energie, IHK Hamburg, H&R Ölmühle Schindler, IVG, Industrieverband Hamburg, Kreis Dithmarschen, Landkreis Harburg, Landkreis Stade, Linde, Offshore Windenergie, Sasol, Shell, Solvay, SWB, Vattenfall, Wasserstoffgesellschaft Hamburg, Yara and the German Federal States Hamburg, Lower Saxony and Schleswig-Holstein

**Characteristics:** Concept for the use of wind-hydrogen in the industrial and transport sectors in the Lower Elbe region proposing the establishment of a hydrogen grid connected to a hydrogen depot in a salt cavern.

**Description:** In 2012, the consortium introduced above commissioned a study for potential business cases from the consultants E&Y, Ludwig-Bölkow-Systemtechnik and BBH. Goal of the study was the identification of business cases for wind-hydrogen application in industry and transport in the Lower Elbe region, further asking when these business cases would be ready for realisation. The study found that wind-hydrogen could be utilised with a hydrogen grid approx. 150 km in length connecting relevant sites in Hamburg, Stade, Brunsbüttel and Heide in Germany. Thus, a local hydrogen market could be established. Initially, the grid would be used for by-product hydrogen that is currently applied for thermal purposes only. Successively, yellow hydrogen (from electrolysis with electricity from electricity stock exchange and high shares of renewable electricity) and finally green hydrogen (solely renewable hydrogen) could be introduced. For this purpose, the establishment of a public-private partnership for funding was recommended. However, implementation is unlikely to succeed.
unless the legal framework for a market for green hydrogen is established, e.g. exemption from grid use fees. Further discussion was encouraged. Whether the relevant stakeholders may reach a common consensus on how to proceed and secure long-term funding remains to be seen.

**BTU Cottbus – Cottbus, Germany**

**Status:** In operation since January 2012.

**Participants:** Hydrogen Research Centre BTU Cottbus

**Characteristics:** 145 kW electrolyser, research facility.

**Description:** Capacity building is under way at the BTU Cottbus to establish required personnel and technological resources for research and development of next-generation alkaline pressure electrolysers. Focus is on the role of the electrolysis system as a component for energy storage and electricity grid control for the accelerated development of renewable energies. Participants in the sub-project at the BTU Cottbus are the Departments for Power Plant Engineering and Safety Engineering.

**Hydrogen refuelling stations in Germany with on-site hydrogen production**

**CEP refuelling station Total Holzmarktstraße – Berlin, Germany**

**Status:** In operation since May 2010.

**Participants:** Total, Linde, Statoil, Hofer, Hexagon, Clean Energy Partnership CEP

**Characteristics:** Hydrogen refuelling station with on-site electrolysis.

**Description:** Hydrogen for the CEP refuelling station in Berlin, Holzmarktstraße is in part produced on-site and in part supplied by the wind-hydrogen plant in Prenzlau. Hydrogen supply is sufficient for the daily service of five buses or 50 passenger cars.

**H2 move – Freiburg, Germany**

**Status:** In operation since December 2011.

**Participants:** Fraunhofer ISE, Air Products, Proton Energy Systems, City of Freiburg, Badenova AG & Co. KG, German Federal State of Baden-Württemberg

**Characteristics:** Hydrogen refuelling station with on-site electrolysis.

**Description:** Hydrogen production at the refuelling station amounts to 6 Nm³/h. Both 35 MPa (slow refuelling) and 70 MPa (rapid refuelling) with SAE J2601 standard are possible.
Figure 26: Hydrogen refuelling station with PV in Freiburg, Germany
(Source: LBST)

Hydrogen refuelling station HafenCity – Hamburg, Germany

**Status:** In operation since February 2012.

**Participants:** Vattenfall, Shell, Hydrogenics, CleanEnergyPartnership CEP

**Characteristics:** 120 kW electrolyser, hydrogen refuelling station with on-site electrolysis.

**Description:** This is a public hydrogen refuelling station with CGH\textsubscript{2} delivery and on-site electrolysis. Both 35 MPa and 70 MPa refuelling is possible. Refuelling of buses with 35 MPa hydrogen is also feasible. The 70 MPa pressure level complies with the SAE J 2601 standard. The refuelling station is equipped with two (optional extension to three) Hydrogenics HySTAT 60 electrolyser for the production of 260 kg hydrogen per day. Furthermore, two medium-pressure tanks storing 215 kg hydrogen at 4.5 MPa each and 120 83 MPa high-pressure cylinders storing approx. 250 kg hydrogen are installed. The electricity used for electrolysis is certified ‘green’ electricity.

EnBW hydrogen refuelling station – Stuttgart, Germany

**Status:** In operation since March 2013.

**Participants:** EnBW, Linde, Hydrogenics

**Characteristics:** 400 kW, hydrogen refuelling station with on-site electrolysis.

**Description:** The Hydrogenics PEM electrolyser produces 60 Nm\textsuperscript{3}/h or 120 kg hydrogen per day. Filling of vehicle tanks is carried out for 70 MPa.

Airport refuelling station BBI – Berlin, Germany

**Status:** Completed. Opening 23 May 2014
Participants: Total, Linde, Enertrag, Berlin Brandenburg Airport

Characteristics: 500 kW electrolyser, hydrogen refuelling station with on-site electrolysis, hydrogen storage, reconversion, feed-in into the natural gas grid.

Description: A number of alternative fuels will be offered. Operation of the refuelling station will be CO₂ neutral covering energy demand with wind and solar energy. The 500 kW electrolyser is manufactured by Enertrag and produces 200 kg hydrogen per day. Volumes between 1000 and 2000 kg hydrogen may be stored at 4.5 MPa. The installation and technical operation is carried out by Linde. Need-based reconversion via biogas CHP plant and feed-in into the natural gas grid is possible.

Activities in Europe

Synthetic methane

Demonstration project Apartment Complex – Rozenburg, Netherlands

Status: Proposed.

Participants: Stedin, DNV KEMA, City of Rotterdam Rozenburg, Residence Department

Characteristics: Small PtG plant for production, methanation and feed-in into the local gas grid for use in private households.

Description: The demonstration project is scheduled to start in late 2013 and run for three years. Hydrogen production is carried out with an electrolyser. After methanation, the produced methane (1-2 Nm³/h CH₄) is fed into the local gas grid for use in an apartment complex.

Direct hydrogen application

Research project Upper Austria – Haid/Ansfelden, Austria

Status: In operation since late 2012.

Participants: OÖ.Ferngas, Fronius International GmbH

Characteristics: Micro-application for private use.

Description: Solar electricity is used for the production of hydrogen via electrolysis (1.2 Nm³/h) with a Fronius Energy Cell. The hydrogen is fed into the natural gas grid, waste heat of the appliance is also utilised.
House of the future – Wels, Austria

**Status:** In operation.

**Participants:** Fronius, Sauter, Linde, ECOScience, Banner, Samsung

**Characteristics:** Micro-application for private use.

**Description:** The goal of this installation is to increase the use of own energy produced by photovoltaic systems. Depending on consumer behaviour and weather, complete supply with electricity and heat may be achieved. The Fronius Energy Cell is equipped with both electrolyser and fuel cell. In combination with a hydrogen tank, it may store energy for the entire year.

Project INGRID – Troia (Apulia), Italy

**Status:** Proposed.

**Participants:** Enel, Hydrogenics, Engineering Ingegneria Informatica, Agenzia per la tecnologia e l’innovazione ARTI, McPhy Energy SA, Ricerca sul Sistema Energetico RSE, Tecnalia

**Characteristics:** 1.2 MW demonstration plant for hydrogen production and grid stabilisation.

**Description:** In this EU project, hydrogen is produced via electrolysis, stored in hydrides and reconverted via fuel cells or made available as a feedstock or energy carrier. The hydrogen storage capacity exceeds one ton or 33 GWh.

GHRYD – Dunkerque, France

**Status:** Proposed project

**Participants:** GDF SUEZ, GrDF, AREVA, McPhy, INERIS, CETH2, CETIAT, CEA, DK’BUS, Dunkerque

**Characteristics:** PtG plant with hydrogen feed-in into the natural gas grid and supply of Hythane®.

**Description:** Hydrogen will be fed into the natural gas grid at district level. At the same time, Hythane®, a hydrogen-natural gas blend, will be supplied as fuel for natural gas vehicles. In Dunkerque, buses are already operated with Hythane® in the ALT-HY-TUDE project.

HyCUBE / MYRTE project – Corsica, France

**Status:** In operation since January 2012.
Participants: AREVA, KIC InnoEnergy / CCAV Alps Valleys, CEA-LITEN, the Pasquale Paoli University of Corsica in Ajaccio, McPhy

Characteristics: 50 kW PtG plant for electricity storage and grid balancing via reconversion with a fuel cell.

Description: A 560 kWp photovoltaic system is connected with an AREVA energy storage system consisting of electrolyser (50 kW PEM, 10 Nm³/h hydrogen) and fuel cell (100 kW). The gas storage volume is 1400 Nm³ hydrogen and 700 Nm³ oxygen at 3.5 MPa storage pressure. The stored energy amounts to 1.75 MWh.

Figure 27: PtG plant in Corsica, France (Source: McPhy Energy, Photo by: Sebastien Aude, Balloide Photo)

Sotavento grid stabilisation – Galicia, Spain

Status: In operation.

Participants: gasNatural fenosa, Hydrogenics

Characteristics: Wind park with on-site electrolysis for hydrogen production and reconversion via combustion engine.

Description: This is a research and technology demonstration plant to improve the implementation of renewable energy systems. The wind park consists of 24 wind turbines equipped with different technologies. The system further contains a Hydrogenics HySTAT 60 Outdoor electrolyser producing 60 Nm³/h hydrogen, a compressor, a storage depot, and a combustion engine for reconversion.

Hydrogen village – Vestenskov (Lolland), Denmark

Status: Project start 2006

Participants: City of Vestenskov, Dansk Mikrokraftvarme, IRD

Characteristics: Construction of a hydrogen grid for private households.
Description: In Vestenskov (Denmark), hydrogen is produced via electrolysis from excess wind energy and fed into a hydrogen grid for use in private households applying fuel cells as mini CHP plants for heat and electricity generation. Initially, the project ran from 2006 to 2012 and connected 30 households to the hydrogen grid. However, the project is going to be extended and further households will be connected to the grid.

Wind-hydrogen plant Utsira – Utsira, Norway

Status: Project duration 2004 – 2010

Participants: Norsk Hydro, Enercon, Enova, NFR, SFT

Characteristics: Independent energy supply via wind-hydrogen for 10 households

Description: A 600 kW wind energy plant supplies 10 households via a low-voltage mini grid. In addition, hydrogen is produced and stored with a 50 kW electrolyser. The hydrogen is reconverted via fuel cell and hydrogen-fuelled combustion engine based on demand. An additional flywheel and a battery were installed. The project was initially scheduled to run for two years, yet the plant remained in operation for almost six years.

Glamorgan Smart Grid project – Port Talbot, United Kingdom

Status: In operation since 2008.

Participants: Air Liquide, Hydrogenics, Glamorgan University

Characteristics: Small PtG plant with hydrogen refuelling station.

Description: In Baglan Energy Park, a Hydrogenics HySTAT 10 Indoor electrolyser producing 10 Nm³/h hydrogen is operated with solar and wind energy. The hydrogen is in part reconverted via fuel cell and in part utilised as fuel for a minibus operated by the university.

Trial for domestic wind turbine energy storage – Cheshire, United Kingdom

Status: Proposed.

Participants: Clean Power Solutions Ltd, Acta S.p.A

Characteristics: Micro-application for private use.

Description: Initial trials aim to use electricity produced by a 20 kW wind energy plant only partially for feed-in into the electricity grid. The remaining electricity is used for hydrogen production via electrolysis. The hydrogen is stored on-site and used for heating purposes on demand.
Hydrogen refuelling stations in Europe with on-site hydrogen production

Table 21 summarises hydrogen refuelling stations with on-site hydrogen production via electrolysis. The production capacity is reported when known.

Table 21: Hydrogen refuelling stations in operation in Europe (excl. Germany) with on-site hydrogen production

<table>
<thead>
<tr>
<th>ID</th>
<th>Country</th>
<th>City</th>
<th>Name</th>
<th>Remarks / Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>199</td>
<td>AT</td>
<td>Graz</td>
<td>HycenT Hydrogen Center Austria</td>
<td>65 kg/day with &quot;green&quot; electricity; to be doubled to 130 kg/day</td>
</tr>
<tr>
<td>400</td>
<td>BE</td>
<td>Halle</td>
<td>WaterstofNet station Brussels</td>
<td></td>
</tr>
<tr>
<td>416</td>
<td>CH</td>
<td>Brugg</td>
<td>Brugg CHIC station (stationary and mobile)</td>
<td>on-site, with electricity from renewable sources; up to 130 kg/day, 60 Nm³/h</td>
</tr>
<tr>
<td>315</td>
<td>DK</td>
<td>Copenhagen</td>
<td>Copenhagen 1</td>
<td>new station with electrolysis on-site with certified renewable electricity 100 kg/day</td>
</tr>
<tr>
<td>205</td>
<td>ES</td>
<td>Zaragoza</td>
<td>EXPO ZARAGOZA 2008</td>
<td>on-site; 24 kg/day; 12 Nm³/h</td>
</tr>
<tr>
<td>393</td>
<td>ES</td>
<td>Sanlúcar la Mayor - Seville</td>
<td>Hercules Project in Seville</td>
<td>on-site with electricity from solar power</td>
</tr>
<tr>
<td>273</td>
<td>GB</td>
<td>Stornoway, Isle of Lewis</td>
<td>H2 SEED Facility: Hebridean Hydrogen Park</td>
<td>using renewable electricity. Alkaline electrolyser (rated at 5 Nm³/h at pressures up 1.2 MPa). Renewable electricity sourced from on-site biogas CHP unit and wind turbine</td>
</tr>
<tr>
<td>327</td>
<td>GB</td>
<td>Leicestershire</td>
<td>Loughborough Hydrogen Vehicle Refuelling Station</td>
<td></td>
</tr>
<tr>
<td>357</td>
<td>GB</td>
<td>Nottingham</td>
<td>Midlands Hydrogen ring - Nottingham</td>
<td>5 kg/day</td>
</tr>
<tr>
<td>378</td>
<td>GB</td>
<td>Sheffield</td>
<td>ITM Power Green Hydrogen Refuelling Station</td>
<td></td>
</tr>
<tr>
<td>418</td>
<td>IT</td>
<td>Milano - San Donato</td>
<td>Milano CHIC station</td>
<td>with solar energy</td>
</tr>
<tr>
<td>388</td>
<td>NO</td>
<td>Oslo - Oppegård</td>
<td>Oslo Bus station CHIC</td>
<td>60 Nm³/h, 250 kg/day; electricity from renewable energy</td>
</tr>
<tr>
<td>389</td>
<td>NO</td>
<td>Skedsmo - Kjeller</td>
<td>HyNor Lillestrom hydrogen station</td>
<td>on-site electrolysis via photovoltaics 10 Nm³/h; steam reforming of land fill gas 10 Nm³/h</td>
</tr>
<tr>
<td>426</td>
<td>TR</td>
<td>Istanbul Eyup</td>
<td>Istanbul boat and bus station</td>
<td>on-site 65 kg/day 30 Nm³/h</td>
</tr>
</tbody>
</table>

44 The ID number reports the registration number of the refuelling station from the online database [http://www.h2stations.org](http://www.h2stations.org)
At present, there are specific plans for two additional refuelling stations with on-site production in Rotherham and Aberdeen, UK.

**Activities world-wide**

**Synthetic methane**
Outside Europe, no plants for the production of synthetic methane from hydrogen via electrolysis and subsequent methanation with CO₂ have been reported.

**Direct hydrogen application**

**Ontario grid frequency control – Canada**
**Status:** In operation.
**Participants:** ieso, Hydrogenics
**Characteristics:** Investigation of the responsiveness of a Hydrogenics HySTAT hydrogen generator.
**Description:** A HySTAT S 4000 Indoor plant producing 100 Nm³/h hydrogen is used for frequency control of the electricity grid.

**Emerald H2 wind to hydrogen facility – Minnesota, USA**
**Status:** Proposed.
**Participants:** Emerald H2, Norfolk Wind Energy, Millennium Reign Energy
**Characteristics:** 10 MW wind park for peak load electricity.
**Description:** The system consists of a 10 MW wind park, electrolyser, hydrogen storage and a 1 MW fuel cell for reconversion of the hydrogen produced. Feed-in of wind energy and reconversion is only intended during peak load periods. Annual hydrogen output is 500 t. The project is in the planning stage and scheduled to commence in August 2014.

**Wind2H2 Wind to hydrogen project Boulder – Colorado, USA**
**Status:** In operation since 2009.
**Participants:** NREL, Xcel
**Characteristics:** Research facility.
**Description:** PEM electrolyser from Proton Energy Systems and a Teledyne alkaline electrolyser produce hydrogen with electricity from wind turbines of different sizes (10 and 100
kW). The hydrogen is in part reconverted via a fuel cell during peak load periods. A small hydrogen refuelling station is also available. In 2009, a Mercedes FC vehicle was in operation.

**Smart City Portal – Kitakyushu Japan**

**Status:** In operation since 2010.

**Participants:** Japan’s Ministry of Economy, Trade and Industry METI, City of Yokohama, Toyota City, Keihanna, Iwatani Corp., Yaskawa Electric Corp.

**Characteristics:** Community energy management for the balancing of fluctuating renewable energies.

**Description:** In Kitakyushu City, photovoltaic systems with a combined output of 100 kWp are installed in combination with a small wind turbine. Excess energy in the form of hydrogen is stored and reconverted on demand via a community energy management system.

**Hydrogen refuelling stations with on-site hydrogen production world-wide**

Table 22 summarises hydrogen refuelling stations with on-site hydrogen production currently in operation outside Europe. The production capacity is reported when known.
Table 22: Hydrogen refuelling stations in operation world-wide (excl. Europe) with on-site hydrogen production\textsuperscript{45}

<table>
<thead>
<tr>
<th>ID</th>
<th>Country</th>
<th>City</th>
<th>Name</th>
<th>Remarks / Production capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>148</td>
<td>CA</td>
<td>Surrey</td>
<td>Powertec Station</td>
<td></td>
</tr>
<tr>
<td>220</td>
<td>IN</td>
<td>Faridabad</td>
<td>Faridabad Hydrogen-CNG Dispensing Station</td>
<td></td>
</tr>
<tr>
<td>208</td>
<td>JP</td>
<td>Fukuoka City</td>
<td>Kyushu University</td>
<td>10 Nm\textsuperscript{3}/h</td>
</tr>
<tr>
<td>452</td>
<td>JP</td>
<td>Saitama-shi</td>
<td>Honda Solar Hydrogen Station</td>
<td>on-site with solar power and grid power; capacity 1.5 kg/day</td>
</tr>
<tr>
<td>076</td>
<td>US</td>
<td>Fort Collins</td>
<td>Hydrogen in Fort Collins</td>
<td>on-site with wind power</td>
</tr>
<tr>
<td>088</td>
<td>US</td>
<td>Taos</td>
<td>Angel's Nest</td>
<td>on-site, with solar power and wind power (2 kg of hydrogen per day with 2.5 amps @ 120 V AC)</td>
</tr>
<tr>
<td>074</td>
<td>US</td>
<td>Crane</td>
<td>NSWC Hydrogen Fueling Station</td>
<td>2 kg/day</td>
</tr>
<tr>
<td>201</td>
<td>US</td>
<td>Burlington</td>
<td>Vermont PEM Electrification H\textsubscript{2} Fueling System</td>
<td>electricity from renewable energy; H\textsubscript{2} production 12 kg/day</td>
</tr>
<tr>
<td>289</td>
<td>US</td>
<td>Wallingford</td>
<td>Proton Energy headquarter - East Coast Hydrogen Highway</td>
<td>on-site from solar power (75 kW) 100 kg/day</td>
</tr>
<tr>
<td>109</td>
<td>US</td>
<td>Lake Havasu National Park</td>
<td>Lake Havasu Ford Filling Station</td>
<td>1 kg/h; can fuel up to 50 vehicles a week</td>
</tr>
<tr>
<td>022</td>
<td>US</td>
<td>Phoenix</td>
<td>Arizona Public Service Alternative Fuel Pilot Plant</td>
<td>on-site and off-site production</td>
</tr>
<tr>
<td>272</td>
<td>US</td>
<td>Arcata</td>
<td>Humbolt State University’s Schatz Energy Research Center</td>
<td></td>
</tr>
<tr>
<td>200</td>
<td>US</td>
<td>Emeryville</td>
<td>AC Transit - Emeryville</td>
<td>electrolysis on-site with 575 kW solar power plant; capacity 65 kg/day; combined with delivered H\textsubscript{2} capacity up to 600 kg/day</td>
</tr>
<tr>
<td>056</td>
<td>US</td>
<td>Oakland</td>
<td>AC Transit Chevron-Texaco Hydrogen Energy Station</td>
<td>electrolysis on-site with solar power and steam reforming of natural gas, capacity 360 kg/day</td>
</tr>
<tr>
<td>045</td>
<td>US</td>
<td>Torrance</td>
<td>Torrance Toyota Station</td>
<td></td>
</tr>
<tr>
<td>023</td>
<td>US</td>
<td>Torrance</td>
<td>Honda Solar Hydrogen Refueling Station</td>
<td>with electricity from solar power or from the grid</td>
</tr>
<tr>
<td>118</td>
<td>US</td>
<td>Santa Monica</td>
<td>Santa Monica - South Coast Air Quality Management District Pro-</td>
<td>electricity from Santa Monica’s “green” electricity (wind, biomass and geothermal)</td>
</tr>
</tbody>
</table>

\textsuperscript{45} The ID number reports the registration number of the refuelling station from the online database http://www.h2stations.org
<table>
<thead>
<tr>
<th>ID</th>
<th>Country</th>
<th>City</th>
<th>Name</th>
<th>Remarks / Production capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>054</td>
<td>US</td>
<td>Diamond Bar</td>
<td>SCAQMD Hydrogen Highway Network Fueling Station in Diamond Bar</td>
<td>12 kg/day; planned for 2015: 180 kg/d</td>
</tr>
<tr>
<td>112</td>
<td>US</td>
<td>Los Angeles</td>
<td>California State University Los Angeles (CSU LA) Hydrogen Fueling Station</td>
<td>electricity from renewable energy 65 kg/day</td>
</tr>
<tr>
<td>062</td>
<td>US</td>
<td>Burbank</td>
<td>SCAQMD Burbank</td>
<td>Proton Hogen 200 electrolyser; 116 kg/day</td>
</tr>
<tr>
<td>332</td>
<td>US</td>
<td>West Los Angeles</td>
<td>Shell station</td>
<td>with &quot;green electricity&quot;, 32 kg/day / 15 Nm³/h</td>
</tr>
<tr>
<td>337</td>
<td>US</td>
<td>Charleston</td>
<td>Charleston’s Yeager Airport station</td>
<td>on-site with off-peak electricity from fossil plants 12 kg/day</td>
</tr>
<tr>
<td>354</td>
<td>US</td>
<td>Hempstead - Point Lookout</td>
<td>Hempstead Long Island</td>
<td>12 kg/day; electricity from wind power</td>
</tr>
<tr>
<td>379</td>
<td>US</td>
<td>Boulder</td>
<td>National Wind Technology Center NWTC</td>
<td>electricity from wind power</td>
</tr>
<tr>
<td>395</td>
<td>US</td>
<td>Brookville</td>
<td>Dull Farm Hydrogen Station</td>
<td>with electricity from wind and solar power 2.5 kg/day</td>
</tr>
<tr>
<td>401</td>
<td>US</td>
<td>Honolulu Oahu</td>
<td>Hawaii hydrogen infrastructure</td>
<td>on-site 10-20 kg/day</td>
</tr>
<tr>
<td>461</td>
<td>US</td>
<td>Honolulu</td>
<td>Fuel Cell Scooter Station</td>
<td>on-site from solar power 200 l/h</td>
</tr>
</tbody>
</table>
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