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ADVANCED REVIEW

On the long-term prospects of power-to-gas technologies

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Electricity generation from variable renewable energy sources such as wind and solar has grown in some countries at such a high rate that long-term storage becomes relevant. The main rationale of power-to-gas (P2G) conversion of excess power is that the capacity of the gas pipelines and gas storage is much higher than that of the electricity transmission lines. This paper investigates the market prospects of hydrogen and methane from P2G conversion as a long-term electricity storage option. Of specific interest is the future development of investment costs, economies-of-scale, the impact of the electricity price, and its distribution as well as possible locations. We conclude that from an economic point-of-view, the future prospects of all P2G technologies are much less promising than currently indicated in several papers and discussions. It will become very hard for P2G to compete in the electricity markets despite a high technological learning potential. However, for both hydrogen and methane, there are prospects for use in the transport sector. Already today compressed gas vehicles are by and large competitive.

This article is categorized under:
Concentrating Solar Power > Economics and Policy
Energy Systems Economics > Economics and Policy
Energy Systems Analysis > Systems and Infrastructure
Energy and Transport > Economics and Policy

KEYWORDS
costs, hydrogen, methane, renewable energy, storage, transport sector

1 | INTRODUCTION

One of the major targets of the European Commission's energy policy is to increase electricity generation from renewable energy sources (RES-E), and indeed, due to supporting policy measures, the amount of RES in the total electricity supply has increased substantially. The almost exponential growth of photovoltaic (PV) and wind in the EU-28 in recent decades is shown in Figure 1.

In some countries, such as Germany and Austria, excess electricity generation from variable renewable energy sources such as wind and solar has led to calls for additional long-term storage capacities, for example IEC (2011). One of the most considered options in this context are so-called power-to-gas (P2G) conversion technologies. A major argument for this is that the capacity of gas pipelines and gas storage is much higher than that of electricity transmission lines where bottlenecks[1] can occur in the electricity transmission grid, for example, in Germany. Hence, if we are comparing the ability to transfer power (energy) from A to B, the idea is that energy can be transported much easier and in much larger amounts via the gas grid than the electricity network.[2] In principle, P2G encompasses the conversion of electricity into gases, into hydrogen and finally into methane. Figure 2 depicts the basic principle of this process.

With increasing variable electricity in mind, academic investigations on gas-based electricity storage for stand-alone power supply systems were conducted already as early as the 1990s (Enea, 2016). Such systems involved hydrogen production with water electrolysis from wind and solar energy, hydrogen storage, and conversion back to electricity with a fuel cell during

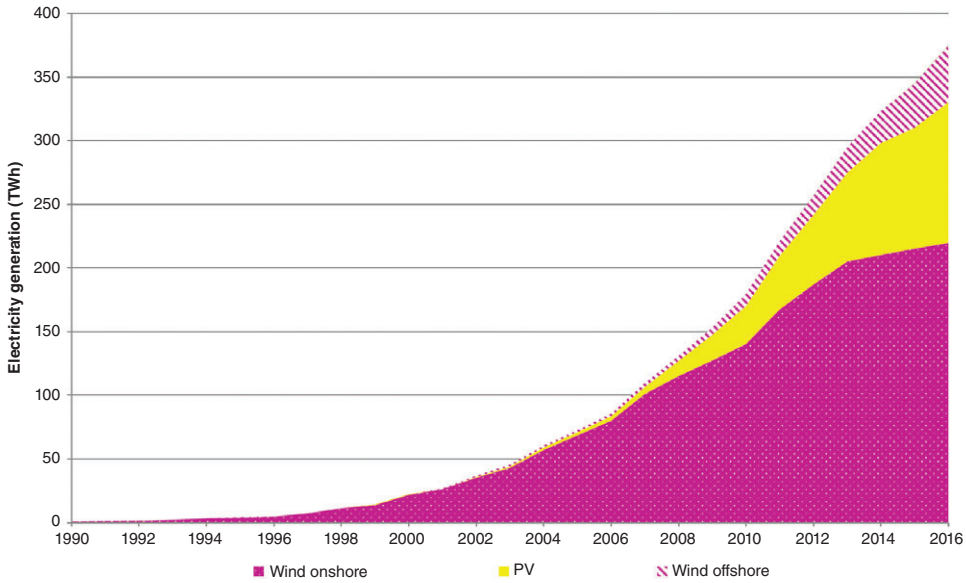

FIGURE 1 Development of electricity from variable renewable energy sources such as wind and photovoltaic in EU-28 (data source EUROSTAT)

power shortage periods. As stated in Enea (2016) "the emergence of the PEM technology was allowing faster response time of the electrolyser compared to alkaline technology probably contributed to the growing interest in power-to-gas-to-power systems for direct coupling with solar panels or wind turbines (Crockett, Newborough, & Highgate, 1997)". The use of methanation also emerged during this period as a solution to CO_2 reuse.

The practical use of P2G as a means to store high quantities of electricity in high wind penetration contexts emerged also in the early 2000s. As Gonzalez, McKeogh and Gallachoir, (2003) describes, hydrogen for mobility was then assessed as economically more attractive than stationary power generation but still not viable due to high investment costs of electrolysers and the need of low prices for electricity. Next, the feed-in of hydrogen into the natural gas grid was proposed as storage option and investigated at laboratory scale (Anderson & Leach, 2004; Schouten, Michels, & Janssen-van Rosmalen, 2004; Schouten, Janssen-van Rosmalen, & Michels, 2006). Figure 3 illustrates the research on and development of P2G concepts since 1994.

After the investigations on the labor stage, the first pilot projects of P2G were launched between 2004 and 2009 with operational testing of technologies between 2007 and 2012. The pilot project in Lolland (Denmark) was one of the first tests of hydrogen production and use, at domestic scale with micro electrolysers and CHP (combined heat and power) fuel cells. Most of later industrial R&D activity on P2G was oriented on grid injection or mobility applications rather than on autonomous energy systems (Enea, 2016). In 2005 and 2006, pilot projects of power-to-hydrogen for mobility and grid injection were launched in the United Kingdom and in the Netherlands, respectively. The first pilot project of power-to-methane with catalytic methanation was been launched later in 2009 in Germany (Enea, 2016).

R&D activities on P2G have been mostly concentrated in Europe with about 90% of all projects launched worldwide since 2004. Even though Japan is particularly active in hydrogen technologies development, it rather focuses on consumption-side technologies, such as fuel cell technologies for vehicles. The United States is just entering the sector with the first P2G project announced in 2015 for testing hydrogen injection in a simulated natural gas pipeline (Enea, 2016).

A survey of projects in Europe is provided in Table A1. Even though Denmark and the Netherlands were pioneers in P2G and are still active, Germany is now leading the European R&D activity. The by far largest number of projects is situated in

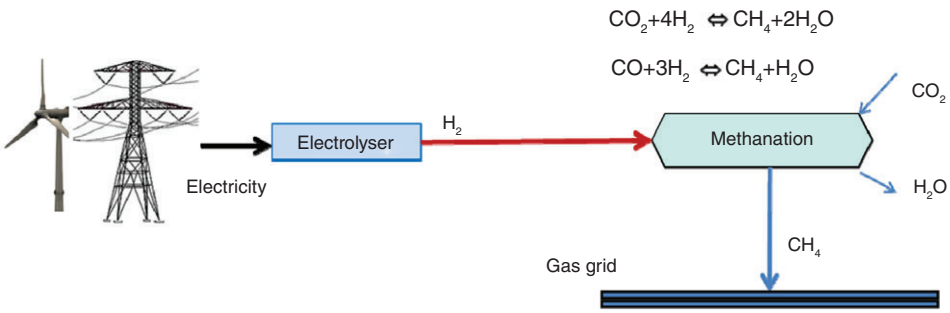

FIGURE 2 Basic principle of the P2G process: Converting electricity into hydrogen and methane

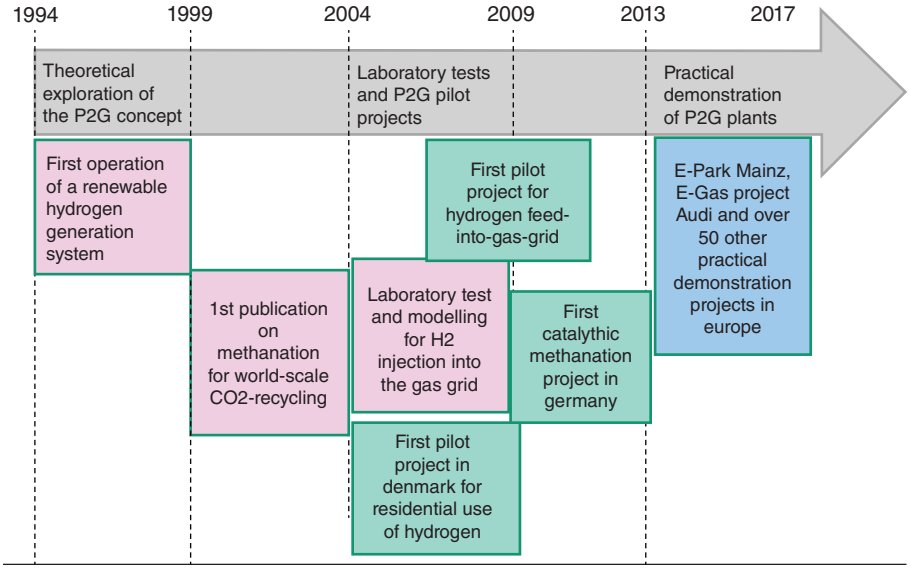

FIGURE 3 Historical development of P2G conversion technologies from laboratory to demonstration plants. (Adapted from Enea (2016))

Germany. About 20 pilot and demonstration projects have been implemented in Germany since 2004. Germany's interest for P2G is directly linked with its Energiewende and high targets of renewable electricity production, while R&D activities in France and in the United Kingdom are much less relevant than in Germany (Enea, 2016).

Different issues related to P2G have been already discussed in literature. For example, Bailera, Lisbona, Romeo, and Espatolero (2017) have done a comprehensive documentation of P2G projects with the major focus on three-step P2G paths (methanation through the application of renewable hydrogen). A review on the role of storage in energy systems with a focus on P2G is provided by Blanco and Faaij (2018). This study has put in perspective the amount of storage needed and its comparison with the possible alternatives to satisfy it. Technoeconomic and environmental life cycle assessment of P2G systems is analyzed by Parra, Zhang, Bauer, and Patel (2017) emphasizing that only the input of renewable electricity to electrolysis result in environmental benefits for P2G compared with conventional gas production. More detailed regional and local technoeconomic analyses of the future role of P2G in the energy transition in Baden-Wüttemberg is estimated by McKennaa et al. (2018). Fendt, Buttler, Gaderer, and Spliethoff (2016) conducted comparison of synthetic natural gas production pathways for the storage of renewable energy. Lund, Lindgren, Mikkola, and Salpakari (2015) provides the so far most comprehensive review of energy system flexibility measures to enable high levels of variable renewable electricity.

However, the major shortcoming of most studies on the future of P2G is that they largely overlook economics. In this context, the most important issues are: (a) the number of possible full-load hours (FLH); (b) and whether grid fees are to be paid or not. In this paper, we close this gap and show in dynamic scenarios how the cost and the corresponding economics may develop depending on economics-of-scale and technological learning.

The core objective of this paper is to investigate the future market prospects of P2G conversion technologies and hydrogen and methane as long-term electricity storage options. Of specific interest is the analysis of the future development of investment costs, possible economies-of-scale, realistic maximal FLH, the impact of the electricity price as well as technological learning.

2 | CURRENT CHALLENGES IN THE ELECTRICITY SYSTEM AND THE ROLE OF P2G

As stated above, the major motivation for discussing P2G technologies comes from the increasing use of variable RES such as wind and solar energy in electricity generation. The consequences of such developments are shown in Figure 4 where a hypothetical scenario of high levels of electricity generation from wind, PV, and run-of-river hydro plants over a week in summer is depicted using synthetic hourly data for an average year in Austria. It can be seen that at some points-of-time, there is excess generation, at other times, there is under coverage.[3]

With the increasing use of PV and wind for electricity generation, increasing amounts of cheap or even free excess energy also become available at specific times of a week and a year. As seen in Figure 5, the variability of renewable electricity generation fluctuates over a year and leads to the need for long-term storage options. Note that electrification of transport and heat will also affect the demand shape. For example, excess from PV is mainly available in the summertime. This excess electricity can be stored and used later to cover demand at times of undercoverage of variable electricity from RES.

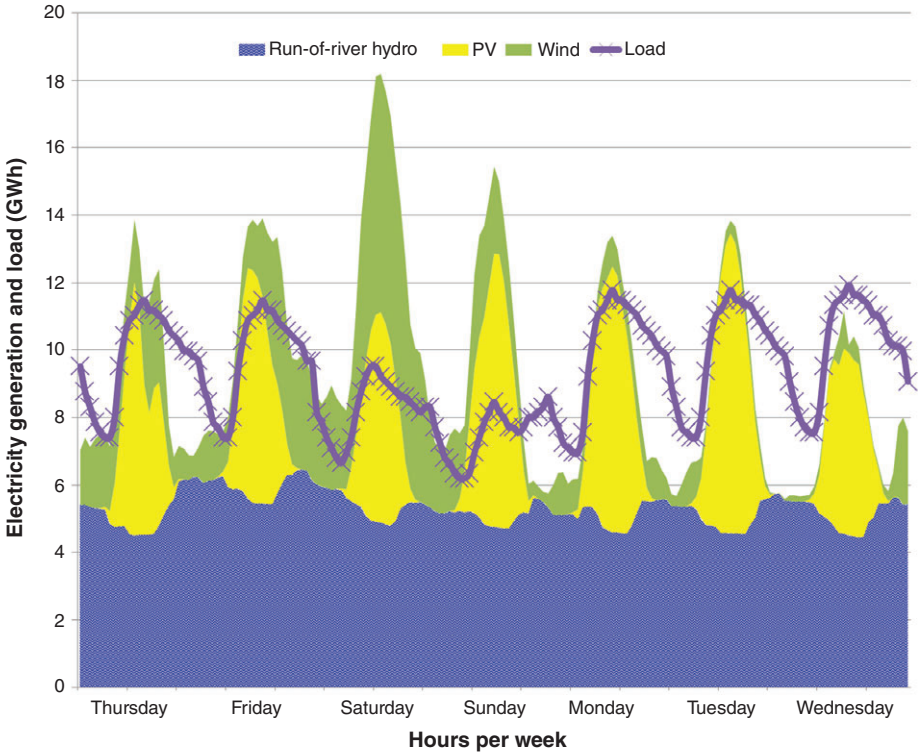

FIGURE 4 Example: Electricity generation from variable renewables (wind, photovoltaic, and run-of-river hydro) over a summer week on an hourly base in comparison to demand. (Adapted from Haas, Lettner, Auer, & Duic, 2013)

Currently, there are different options to store electricity. Figure 6 provides an overview of storage technologies regarding their discharging time and storage capacities. It can be seen that aside from pumped hydro storage, hydrogen and methane are the most important options for high quantities and long storage times.

We can create different chains for storing electricity over hydrogen and methane. Two major paths of use are (a) hydrogen and methane production from RES-E and their re-electrification according to needs, (b) and their direct use in transport. Figure 7 describes the system for storing electricity in hydrogen and feeding methane into the gas grid. Finally, methane is re-electrificified via a combined-cycled gas turbine. The methane produced is stored and transported via the gas grid.

However, one crucial issue in all P2G supply chains is the low over-all conversion. As an example, Figure 8 depicts the corresponding losses in the methane production and re-electrification chain. As seen in this example, the overall efficiency of the chain is only 33%.

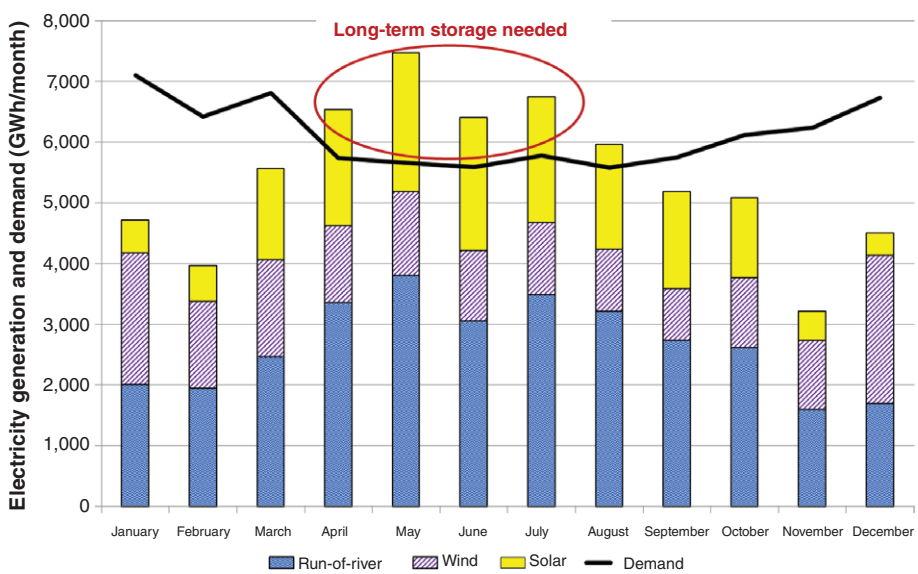

FIGURE 5 Electricity generation from renewable energy source over a year and the need for long-term storage

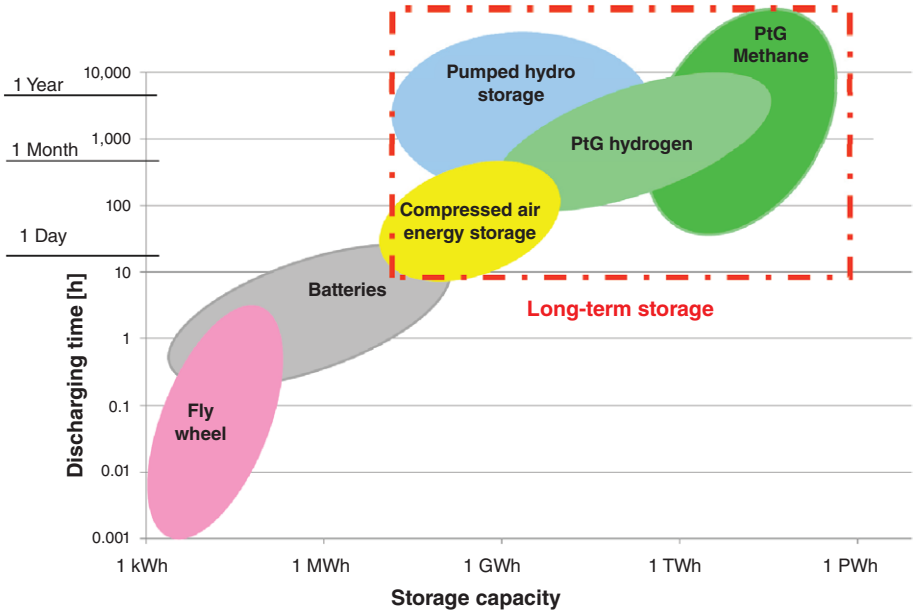

FIGURE 6 Survey on storage options depending on capacity and discharging time (Specht et al., 2010; Leonhard et al., 2009)

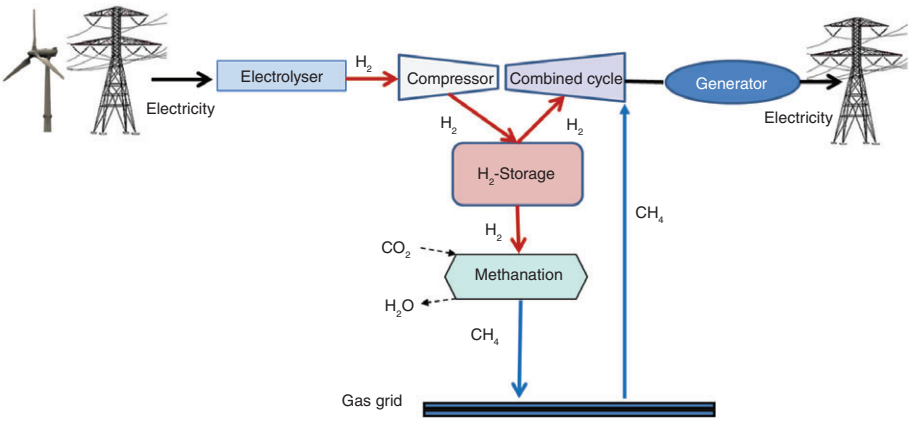

FIGURE 7 The chain for storing electricity as hydrogen or methane and re-electrification via combined cycled gas turbine

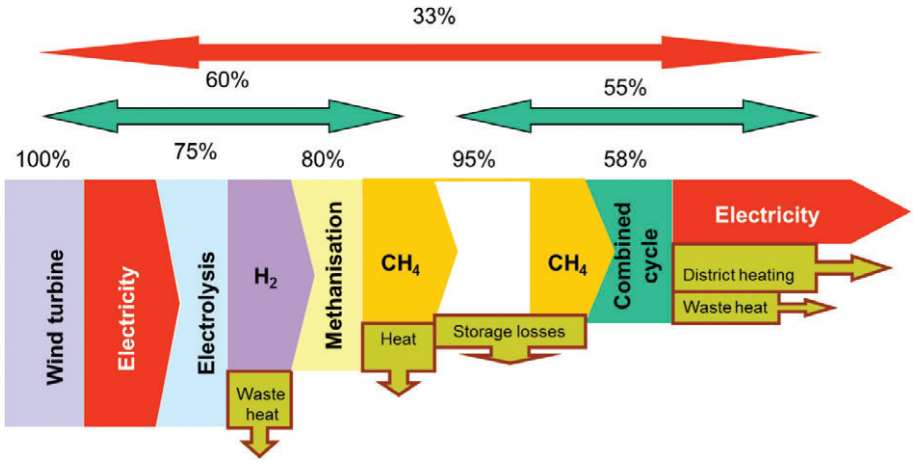

FIGURE 8 The chain for producing methane and re-electrification, efficiencies indicated as of 2016

The overall efficiency of 33% is true for the given efficiencies of the substeps in the process chain from electricity to electricity, and does not take into account the utilization of any waste heat sources. It does also not take into account the possible utilization of the oxygen from the electrolysis. Furthermore, the supply of CO_2 is also linked to energy expenditure.

3 | THE COSTS OF HYDROGEN AND METHANE IN P2G

In this section, we analyze the cost of hydrogen and methane from P2G systems depending on plant size, number of FLH, and electricity prices.

Our method is based on simple levelized cost calculation of electricity storages.[4,5] In Equation (1) it is described how the storage cost C_{STO} are calculated:

$$C_{STO} = \frac{\frac{IC \cdot CRF + C_{O\&M}}{T} + C_E}{\eta_{STO}} \text{ (EUR/kWh)}, \tag{1}$$

where, IC is the investment costs, CRF is the capital recovery factor, $C_{O\&M}$ is the operating and maintenance costs, T is the full-load hours (hours per year), C_E is the energy costs, and η_{STO} is the efficiency of storage.

The investment costs of P2G plants for hydrogen and methane production for two capacity categories (500 kW and 10 MW) are shown in Table 1. The corresponding efficiencies of electrolysers and methanizers are summarized in Table 2.

Today mainly small systems with capacities below 500 kW are in operation. However, there are already plans for constructing plants with 10 MW or beyond (Platts, 2018). This would reduce the specific hydrogen generation costs remarkably, see Figure 9.

Figure 10 show the total cost of methanation in large electrolyser system depending on the number of the FLH. In this context, as seen from Equation (1), the cost of electricity is an important parameter for the total methane costs. This figure shows also the classified frequency of the average electricity costs in Austria and Germany in 2016 over a year. It can be seen in Figure 10, that, for example, the average electricity price is about 2–3 cents/kWh for about 4,000 FLH. At some hours of the year, the excess of electricity is the reason for sometimes negative electricity costs.

Finally, it is important to find an optimal balance between the investment costs of the system (depending on the plant size) and possible FLH per year. In this case, the lowest total costs of methane could be reached starting from about 4,500 FLH per year. However, in practice, only a maximum of 2,800 hr/year is a realistic figure. The capital costs per kWh decrease with higher number of FLH according to Equation (1).

The total production costs of hydrogen and methane depending on the FLH of electrolysers are shown in Figure 11.

From Figure 11, we derive that at FLH of 2,800 hr/year, the cost for hydrogen is about 10 cents/kWh, for methane about 16 cents/kWh. At 1,800 hr/year, the costs are considerably higher, for hydrogen about 17 cents/kWh, for methane about 23 cents/kWh, respectively. These figures are further used in the following sections for the calculation of the fuel costs.

4 | USE OF HYDROGEN AND METHANE IN THE TRANSPORT SECTOR

Since the use of hydrogen and methane for electricity generation (re-electrification) is currently too expensive, another opportunity can be their direct use in the transport sector, which is one of the largest emitters of greenhouse gas (GHG) emissions. Due to high emissions especially in road transport increasing use of RES for mobility is becoming more and more important. Currently, the mostly used alternative fuels are biofuels, although more and more criticized in recent years regarding their environmental impact, sustainability and competition with food production (Ajanovic, 2010; Ajanovic & Haas, 2014; Ajanovic, Jungmeier, Beermann, & Haas, 2013). In the last years also a huge effort is put on increasing penetration of electric vehicles. Unfortunately, there are still major technical and economic barriers, such as limited driving range and high investment

TABLE 1 Investment costs in hydrogen and methane production plants for two capacity categories (500 kW and 10 MW) (2016 prices)

	EUR/kW$_{Ele}$	EUR/kW$_{CH4}$	Total cost (EUR/kW$_{Ele}$)
500 kW$_{El}$	2,400	1,200	3,600
10 MW$_{El}$	1,550	1,050	2,600

Notes. Investment costs in electrolysis and methanation, as well as total system costs (including Conversion of electricity, compression, and storage of hydrogen) (Platts, 2018; Steinmüller et al., 2014).

TABLE 2 Efficiency of electrolysis and methanation (for two capacity categories: 500 kW and 10 MW) (Platts, 2018; Steinmüller et al., 2014)

Efficiency of the electrolysis and methanation			
	Efficiency η_{H2} (%)	Efficiency η_{CH4} (%)	Efficiency η_{Total} (%)
500 kW$_{El}$	63	70	44
10 MW$_{El}$	74	80	59

Note. Remark on the efficiency η: Encompasses the conversion efficiency of the electrolysis, compression, and storage of hydrogen.

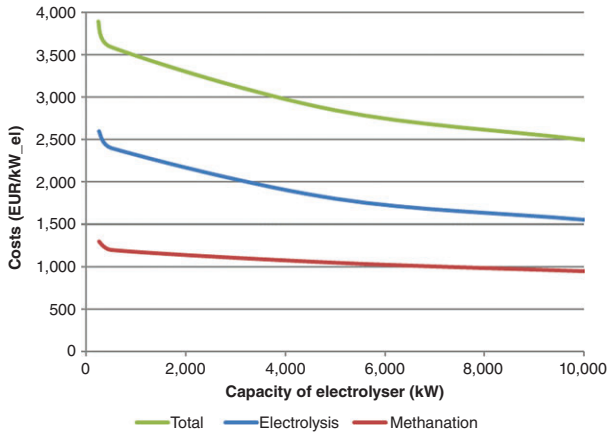

FIGURE 9 Investment costs in electrolysis and methanation, as well as total system costs depending on the electric capacity of the electrolysis (as of 2016)

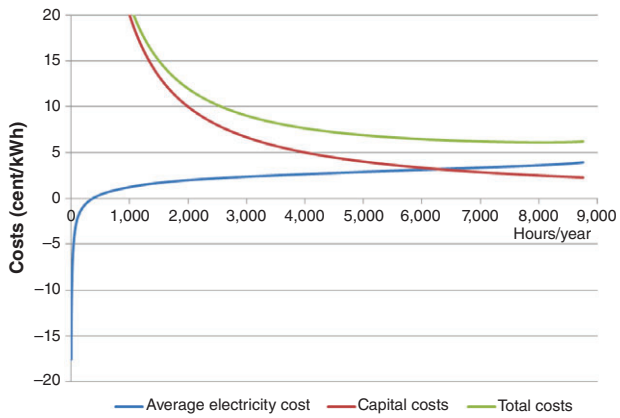

FIGURE 10 Large system: The total cost of methane depending on capital costs, electricity costs, and the number of the full-load hours

costs, curtailing the broader use of battery electric cars (BEV). Hydrogen powered fuel cell vehicles (FCVs) are another possible zero-emission automotive technology, however, due to high costs of fuel cells, this technology is not economically competitive now, but, assuming technological learning and mass production, it could be of interest in the long term, see for example Ajanovic and Haas (2017). As more economical alternative could be use of methane in compressed gas vehicles (CGVs). Possibilities for use of RES for mobility via hydrogen (H_2) and methane (CH_4) is depicted in Figure 12.

In the following, we discuss in detail mobility costs with hydrogen and methane in comparison to conventional automotive technologies.

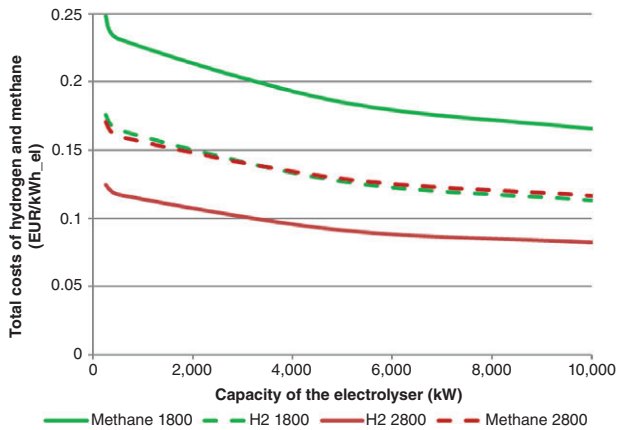

FIGURE 11 Total production costs of hydrogen and methane depending on the full-load hours of operation depending on the electric capacity of the electrolysis (as of 2016)

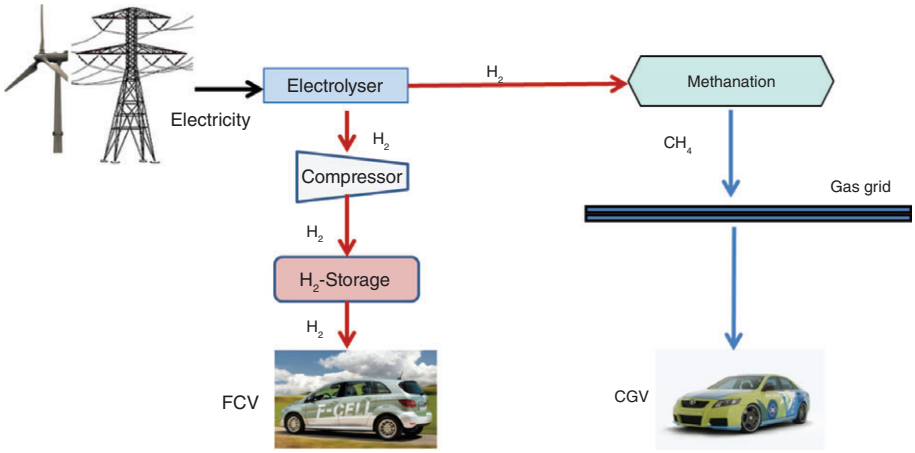

FIGURE 12 The chain for the use of renewable energy source via hydrogen and methane in the transport sector

The costs of hydrogen as well as of methane are very dependent on primary energy used for their production. Energy costs per 100 km driven of different types of vehicles and fuels are shown in Figure 13. Beside energy costs also different taxes (excise tax, value add tax [VAT], and electricity fee) are illustrated.

To reduce costs of hydrogen cheap, excess electricity from variable RES can be used for electrolysis. However, in this case, the number of FLH, which are dependent on availability of excess electricity from wind and PV, have a crucial impact on the total hydrogen costs. The impact of the number of FLH on hydrogen and methane costs is shown in Figure 13 for two different cases: 1,800 and 2,800 FLH. Gasoline and compressed natural gas (CNG) are taken here as a reference. It is obvious that higher number of FLH lead to lower energy costs.

Finally, for the car users of crucial interest are the total costs of mobility. The total costs of mobility per 100 km driven (C_{km}) are calculated according to the following Equation (2):

$$C_{\mathrm{km}} = \frac{\mathrm{IC} \cdot \mathrm{CRF}}{\mathrm{skm}} + P_e \cdot \mathrm{EI} + \frac{C_{\mathrm{O\&M}}}{\mathrm{skm}} [€/100\,\mathrm{km\,driven}], \tag{2}$$

with IC, the investment costs for vehicles [€/car]; CRF, the capital recovery factor, $C_{\mathrm{o\&m}}$, the operating and maintenance costs; skm, the specific km driven per car and year [km/(car.year)]; P_e, the energy price incl. taxes [€/kWh], and EI, the energy consumption [kWh/100 km].

Total energy price (P_e) depends on the costs of the energy carriers (C_e) used such as hydrogen, electricity, gasoline, and so on, and possible taxes (e.g., VAT, excise and CO_2 taxes) implemented.

Last, the total costs of mobility with hydrogen used in FCVs and methane used on CGVs per kilometer driven in comparison to conventional cars (gasoline internal combustion engine (ICE) vehicles) and battery electric vehicles (BEVs) are shown in Figure 14. From this figure is obvious that the number of FLH of the electrolysers has no significant impact on the total costs of mobility. These costs are largely determined by costs of vehicles.

Since the capital costs of vehicles have the largest impact on total mobility costs, a major problem are the high costs of FCV. These costs could be significantly reduced in the future through technological learning and increasing production.

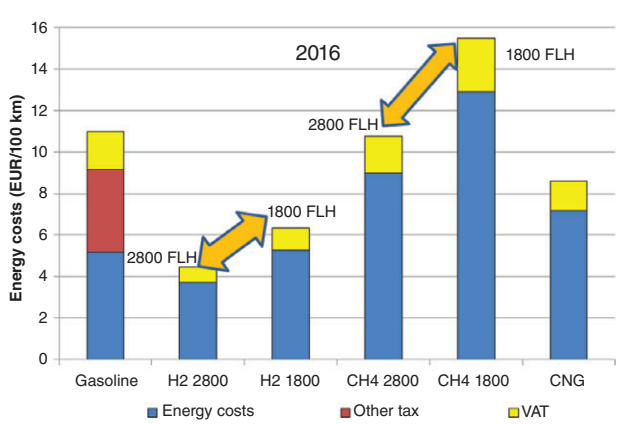

FIGURE 13 Energy (fuel) costs of mobility per 100 km depending on full-load hours of the electrolysers (based on average of EU countries in 2016)

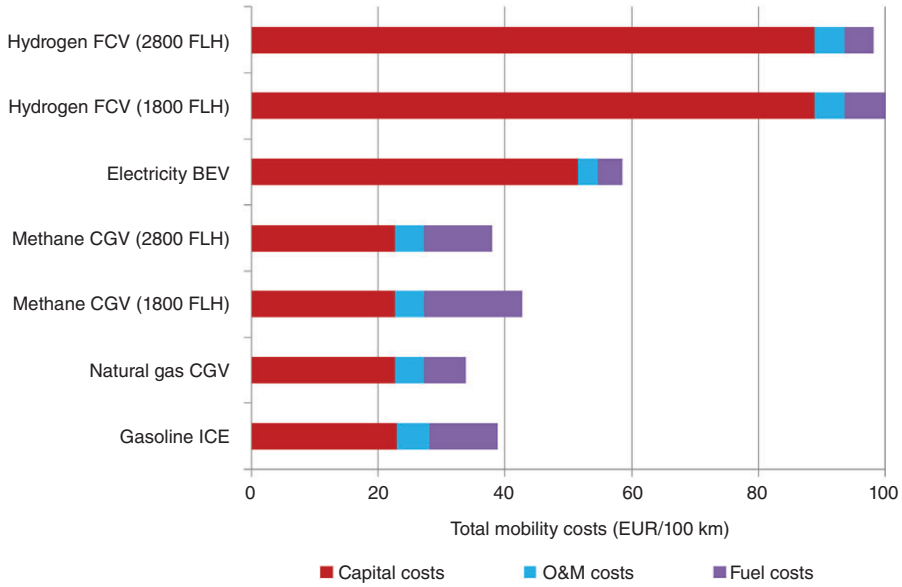

FIGURE 14 Total mobility costs per 100 km in 2016 depending on full-load hours of the electrolysers

However, in the meantime, the use of methane in CGV can be an economically acceptable option. The use of methane in transport can lead to a significant reduction of total transport costs due to much lower costs of CGV in comparison to BEV and especially to FCV, see Figure 14.

For the future use of hydrogen in the transport sector, a remarkable reduction of capital costs is the key issue. From economic point of view, the use of methane in CGV is already now competitive with conventional gasoline cars. However, although the use of CNG in the transport sector is already established, it has extensive use only in some parts of the world (e.g., Pakistan, Argentina, Iran, and Brazil). In the rest of the world, the availability of gas stations is limited. Due to that as well as the fact that CGV have lower driving range than gasoline cars, the largest number of CGV is bi-fuel. This leads to higher cost and lower efficiency.

5 | ECONOMIC PERSPECTIVES FOR P2G TECHNOLOGIES FROM TECHNOLOGICAL LEARNING UP TO 2050

The current economic performance of investigated long-term storage options is rather poor and far from economic competitiveness.[6] Here, we analyze how the prospects could be in the next decades. Of specific interest in this context is the analysis of the future development of investment costs due to technological learning, possible economies-of-scale, realistic number of FLH, and the development of the electricity price. This analysis is based on Ajanovic and Haas (2018) work.

With respect to the future development of the investment costs of alternative powertrains, it is expected that they will be reduced through technological learning. Technological learning is usually illustrated for many technologies by so-called experience or learning curves (Ajanovic, 2008; Junginger, van Sark, & Faaij, 2010). To express an experience curve, we use Equation (3):

$$\mathrm{IC}_{\mathrm{New\_}t}(x) = a \cdot x_t^{-b} \ [€/\mathrm{kW}], \tag{3}$$

with $\mathrm{IC}_{\mathrm{New\_}t}(x)$, the investment cost of new technology; b, the learning index; and a, the investment cost of the first unit.

In Equation (3) x refers to the cumulative capacity of electrolysers installed.

Applying this approach to P2G production plants Figure 15 depicts the future perspectives of the investment cost development of hydrogen and methane for large storage of about 10 $\mathrm{MW_{El}}$ of electrolysers with low and high learning rates, Figure 16 shows these developments for small storage with 500 $\mathrm{kW_{El}}$ of electrolyser. It can be seen that over the period up to 2050 for both sizes the investment costs decrease by about 30% (for low learning rate of 17% some percent less, for high learning rate of 23% some percent more[7]). Based on these developments of the investment costs as next, we calculate the total cost of hydrogen and methane production up to 2050, see Figure 17 and Figure 18.

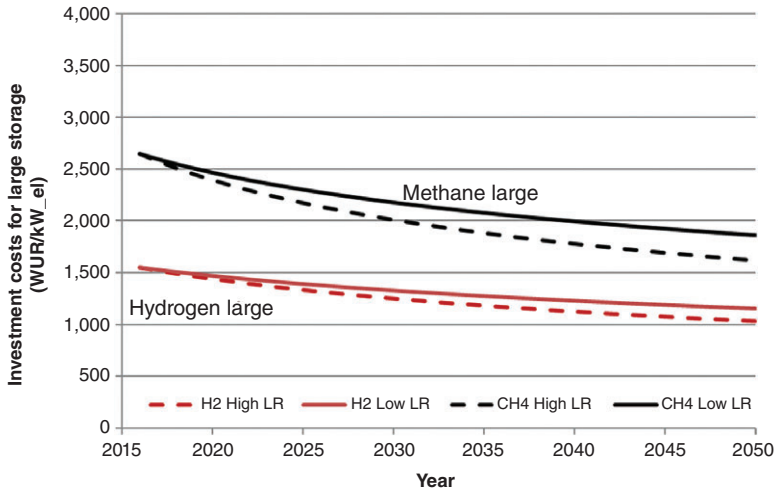

FIGURE 15 Large storage types: Future perspectives of the investment cost of hydrogen and methane with low and high learning rates

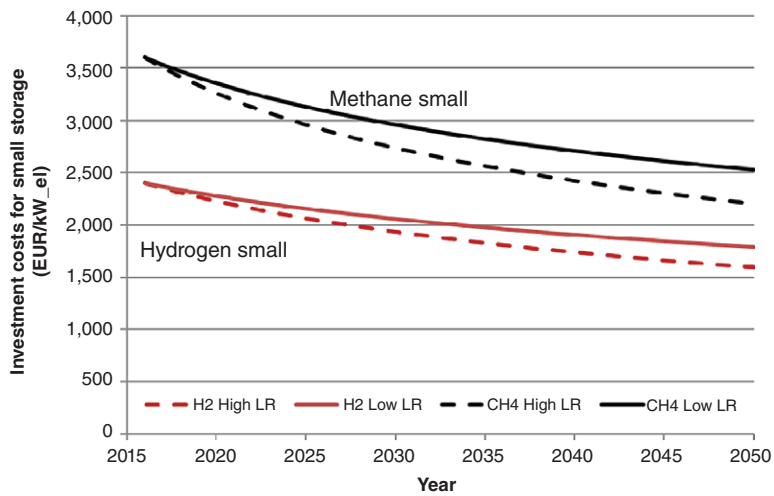

FIGURE 16 Small storage types: Future perspectives of the investment cost of hydrogen and methane with low and high learning rates

In addition to the investment costs, according to Equation (1) also the development of the electricity prices is important. In our scenario, due to higher quantities of excess electricity, the electricity wholesale market prices decrease from 1.8 cents/kWh to 1.5 cents/kWh up to 2050. Given these input parameters by 2050 under most favorable learning conditions (IEA, 2011), the costs of hydrogen for 2,800 FLH per year will be about 6 cents/kWh, the cost of methane about 8–9 cents/kWh.

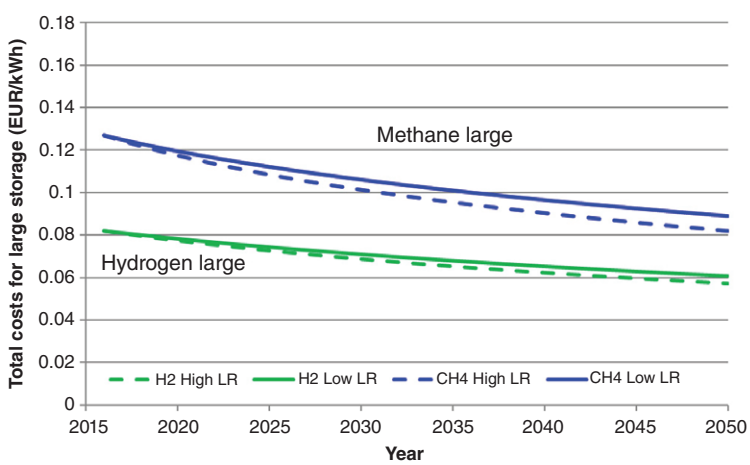

FIGURE 17 Large storage types: Perspectives for the total costs of hydrogen and methane with low and high learning rates over time up to 2050 (full-load hours, FLH = 2,800)

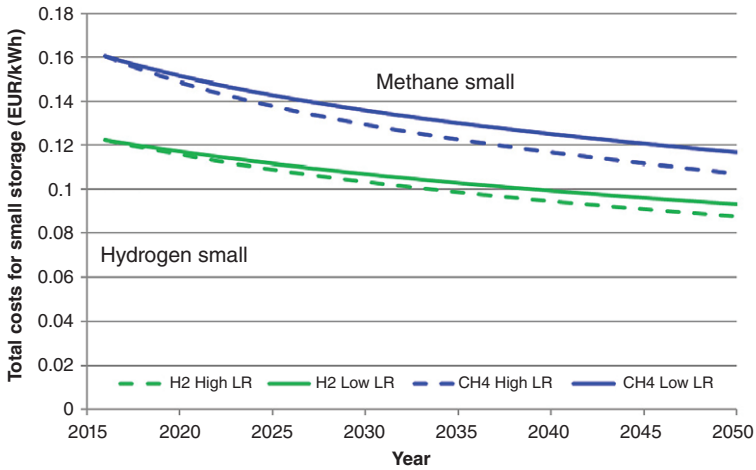

FIGURE 18 Small storage types: Perspectives for the total costs of hydrogen and methane with low and high learning rates over time up to 2050 (full-load hours, FLH = 2,800)

Figure 19 shows the future perspectives of the investment cost for several technologies for long-term storage of electricity for large and small storage types with low and high learning rates. Over the period up to 2050, decreases in the prices of the P2G technologies are expected to take place mainly due to learning effects. For long-term hydro pump storage (over a year), further prices will rather increase mainly due to a lack of sites with reasonable costs and lack of acceptance (see Figure 19). Figure 20 shows the corresponding total costs for a kWh stored in a specific storage medium. This figure clearly shows that the cheapest options up to 2050 will not be lower than 5 cents/kWh. Given that average prices in the electricity markets are currently 3–4 cents/kWh, and there are no reasons for significant increases in the future, it will be very hard for any new storage option to become competitive.

As stated above, by 2050, under most favorable learning conditions, the cost of hydrogen and methane for 1,800 FLH per year will be between 6 cents/kWh and 9 cents/kWh. Based on these costs for hydrogen and methane in Figure 21, the future energy costs are compared. As seen, there are clear cost advantages for the P2G energy carriers compared to the fossil based ones mostly due to implementation of a CO2 taxes. It can be also noticed that the figures for 2080 FLH per year are remarkably cheaper.

Figure 22 depicts the total costs of mobility per 100 km in 2050 depending on the number FLH of the electrolysers. In this scenario, the methane powered cars show the best economic performance while the fossil-based cars have the highest total costs.

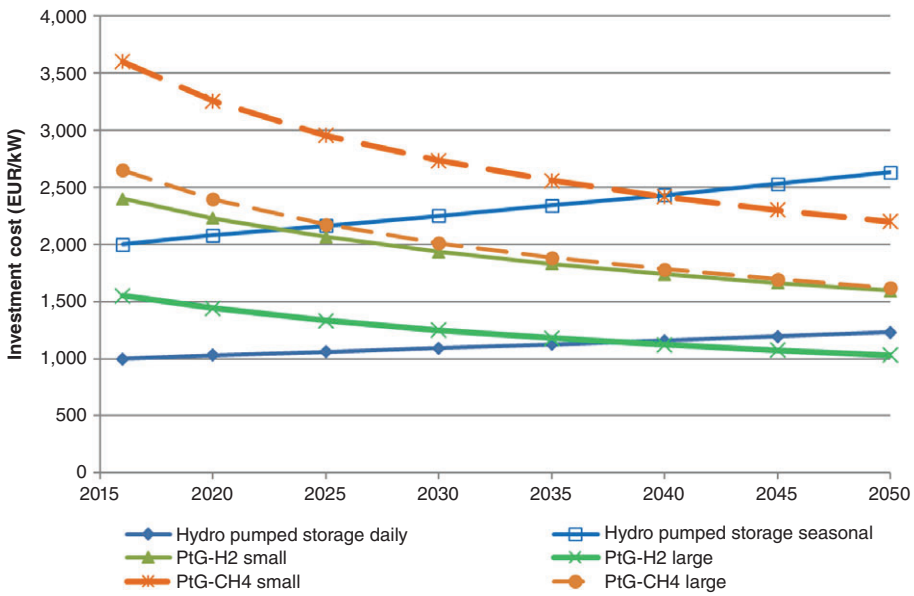

FIGURE 19 Future perspectives of the investment costs for long-term storage of electricity for large and small storage types with high learning rates

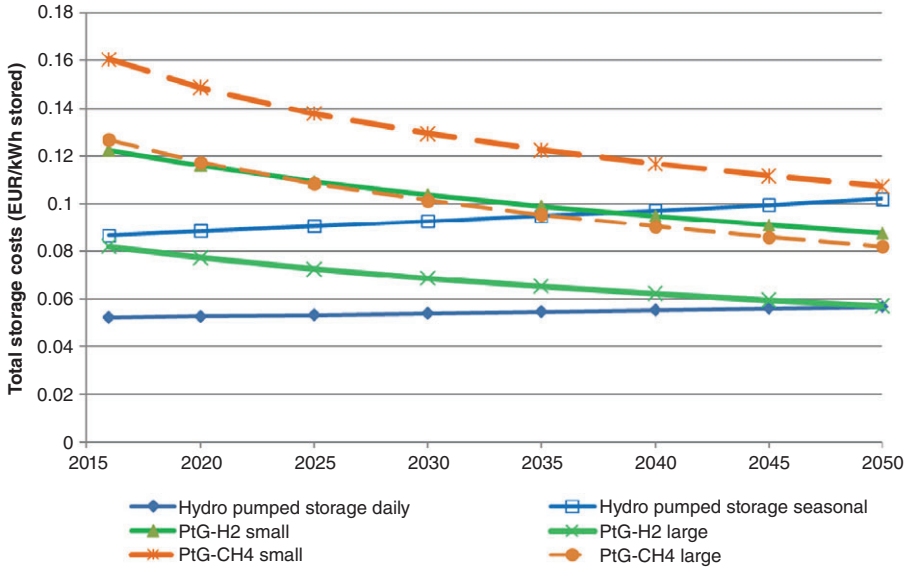

FIGURE 20 Development of total costs of several technologies for long-term storage of electricity for large and small storage type over time up to 2050 (full-load hours, FLH = 2,800)

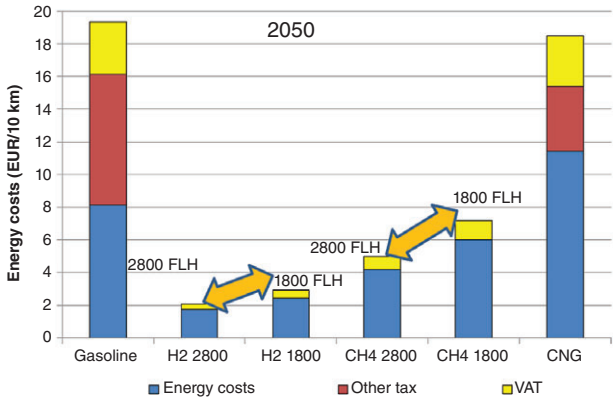

FIGURE 21 Fuel/ energy costs of mobility per 100 km based on average of EU countries in 2050 depending on full-load hours of the electrolysers

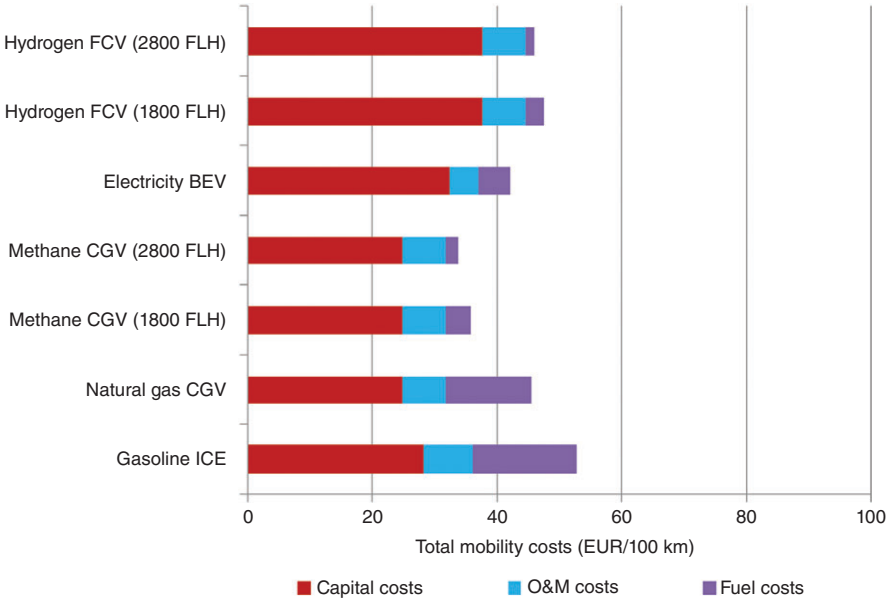

FIGURE 22 Total specific costs per 100 km in 2050 depending on full-load hours of the electrolysis for hydrogen and methane production

6 | CONCLUSIONS

With increasing electricity generation from variable RES and its temporarily cheap overproduction, opportunities for P2G are of interest especially due to the rising need for long-term storage of this surplus electricity. The basic idea of storing electricity in a much more convenient energy carrier such as hydrogen and methane, and using it when and wherever it is needed, is a very appealing.

However, there are some important issues ahead. The major shortcoming of almost all studies on the future of P2G is that they largely ignore the high costs involved and the correspondingly poor economics. The major problems are: high investment costs, low number of FLH, and low overall efficiency in a very long conversion chain. Currently, it seems that it will become very hard for P2G technologies to compete in the electricity system.

What could the future bring with it? We have to differentiate between P2G in the electricity sector and in transport. In the electricity sector, there are the following opportunities:

1. P2G could deliver the final solution to complete a 100% renewable electricity system by providing electricity at on-peak hours with respect to residual load.
2. Because the capacity of gas pipelines and gas storage is much higher than that of the electricity transmission grid via P2G, energy could be transported much easier and in much larger amounts via the gas grid than the electricity network.
3. P2G could provide clean electricity for the very short-term balancing market.

However, for hydrogen as well as for methane, it will become very hard to compete using re-electrification in the electricity markets despite a high technological learning potential. In the electricity sector, there are also other competing options with flexibility measures such as load shifting and demand-side-management (Lund et al., 2015).

In addition to the re-electrification, there are prospects for the use of hydrogen and methane in the transport sector. Fuel prices in transport are rather high and are increasing compared to the stagnation or decrease in prices on electricity spot markets. Consequently and also given the lack of environmentally-benign fuels for mobility, hydrogen and methane from renewable electricity might become realistic alternatives for fueling passenger cars.

The major problem of hydrogen use in transport is the high cost of the FCV. Despite the longer conversion chain and the higher fuel costs, for the next decades, the economics of methane in transport are much better.

In addition, as shown in this analysis, the use of methane from P2G in CGV is already economically competitive today because the investment costs in CGV are much lower than those in FCV. However, a core problem for methane is the low acceptance of gas-powered cars. Currently, acceptance is high in Italy and Spain but rather low in other countries, such as Germany and Austria. Summing up, poor economics and low acceptance will be major barriers to overcome in transport before hydrogen and methane can enter these markets on a significant scale.

CONFLICT OF INTEREST

The authors have declared no conflicts of interest for this article.

ENDNOTES

[1]Of course, if the electricity grid would be extended, there would be less congestion, and also the magnitude of excess renewable generation will be lower.

[2]It has to be acknowledged that there are many alternatives to P2G technologies, for example, hydro storage, demand side management, interconnection to neighbors, decentralized batteries. There is also a general trend toward the electrification of the heat and the transport sector, which might be relevant for the future of P2G.

[3]An obvious issue for most European countries is a high electricity exchange (import/export) with its neighbors. Countries don't operate their power system in isolation. It is clear that if someone wants to buy (use) the energy then the price will no longer be as low as considered without this demand. If P2G was rolled out at scale, then this would have a clear impact on the electricity price.

[4]In addition, our calculations are based on full load hours with an average between full-load efficiency and partial-load efficiency. We also use an average for the time duration between storage charging and discharging periods. Also note that introducing a new load (i.e., P2G) at scale will affect the electricity price.

[5]Note, we do not account for costs of CO2 supply. However, CO2 is not for free because its separation is costly (and pure CO2 sources are rare). Yet, in general, CO2 is subject of the EU trading system and taxes. Our assumption is that costs and revenues of CO2 are balanced.

[6]It should be mentioned that there is also value in storage providing flexibility and reserve services to a system, which may beneficially for pure economic decisions.

[7]The learning index has been chosen according to literature (e.g., McDonald and Schrattenholzer (2001), Kobos, Erickson, & Drennen (2006), Wiesenthal et al. (2012)).

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APPENDIX A

TABLE A1 Selected power-to-gas operational projects in Europe (European Power to Gas, 2018)

Location	Project	Installed power (kW)	H2 production (Nm3/hr)	Application	Output product
Vienna, Austria	Vienna (AT)—underground sun storage	600	120 cu H2/hr	Storage	Hydrogen and Methane
Halle, Belgium	Don Quichote (BE)—Colruyt	150	30	Mobility (forklifts)	Hydrogen
Avedøre, Denmark	Avedøre (DK)—BioCatProject	1,000	200	Gas grid	Methane
SamsØ, Denmark	SamsØ (DK)	20		Mobility	Hydrogen
Avedøre, Denmark	Avedøre (DK)—BioCatProject	1,100	200	Gas grid	Methane
Dunkerque, France	Dunkerque (F)—GRHYD project		10–15	Mobility, gas grid	Hydrogen & Methane
Ajaccio, Corsica, France	Corsica (F)—MYRTE	150	23	Power generation, power storage	Hydrogen
Allendorf, Eder, Germany	Allendorf, Eder (D)—BioPower2Gas	1,100	60–220 H_2 15–55 SNG	Gas grid	Hydrogen and Methane
Frankfurt am main, Germany	Frankfurt am main (D)—Thuga	315	60		Hydrogen
Mainz, Germany	Mainz (D)	3,900	1,000	Mobility, power generation, power storage, industry	Hydrogen
Falkenhagen, Germany	Falkenhagen (D)—DVGW	1,000		Gas grid	Methane
Freiburg, Germany	Freiburg (D)—H2Move	40	6	Mobility	Hydrogen
Prenzlau, Germany	Prenzlau (D)—ENERTRAG AG	600	120	Mobility and power generation/storage	Hydrogen
Falkenhagen, Germany	Falkenhagen (D)—DVGW	1,100		Gas grid	Methane
Stuttgart, Germany	Stuttgart (D)—ZSW II	250	50		Methane
Werlte, Germany	Werlte (D)—Audi AG	6,300	1,300	Gas grid—mobility	Methane
Ibbenbüren, Germany	Ibbenburen (D)—RWE	150	30	Gas grid, heat	Hydrogen
Hamburg-Schnackenburgallee, Germany	Hamburg-Schnackenburgallee (D)	185	30	Mobility	Hydrogen
Rostock, Germany	Rostock (D)—EXYTRON Demonstrationsanlage	21	4 H2 1 SNG	Gas grid, power generation, heat	Methane
Troia, Pulgia, Italy	Puglia region (I)—INGRID project	1,000		Gas grid (regional distribution)	Hydrogen and Methane
Rozenburg, Netherlands	Rozenburg (NL)	10		Gas grid	Methane
Brugg, Switserland	Brugg (CH)—PostBus hydrogen bus	315	60	Mobility	Hydrogen
Aragon, Spain	Aragon (E)—ITHER	4,070		Mobility	Hydrogen
Leicestershire, United Kingdom	Leicestershire (UK)—Hari project	36		Power generation, power storage	Hydrogen

Notes. The numbers used in Figures 13–14, 21, and 22 are based on results of the partial equilibrium model ALTER-MOTIVE created in the scope of the EU project (IEE/07/807/SI2.499569). In the model, same car size (80 kW) for all type categories is assumed as well as same travel activity (12,000 km per year). Detailed data and assumptions are provided in the following tables.

APPENDIX B

TABLE B1 Data used for calculations in Figure 13

2016 Car technology	Energy costs €/100 km	Other tax €/100 km	VAT 20%	Fuel intensity kWh/100 km	Energy price net €/kWh
Gasoline ICE	5.16	4.00	1.83	53.8	0.10
Hydrogen FCV (2,800 FLH)	3.72	0.00	0.74	31.0	0.12
Hydrogen FCV (1800 FLH)	5.27	0.00	1.05	31.0	0.17
Methane CGV (2,800 FLH)	8.98	0.00	1.80	56.1	0.16
Methane CGV (1800 FLH)	12.90	0.00	2.58	56.1	0.23
Natural gas CGV	5.05	0.00	1.44	56.1	0.09

Notes. CGV = compressed gas vehicle; FCV = fuel cell vehicle.

TABLE B2 Data used for calculations in Figure 14

2016	Capital costs	O&M costs	Fuel costs	Investment costs	Distance	Fuel intensity
Car technology	€/100 km	€/100 km	€/100 km	€/car	km/car/Year	kWh/100 km
Gasoline ICE	22.96	5.20	11.00	17,573	12,000	53.8
Natural gas CGV	22.70	4.58	6.49	17,773	12,000	56.1
Methane CGV (1800 FLH)	22.70	4.58	15.48	17,773	12,000	56.1
Methane CGV (2,800 FLH)	22.70	4.58	10.77	17,773	12,000	56.1
BEV	51.44	3.18	3.97	39,828	12,000	19.7
Hydrogen FCV (1800 FLH)	88.88	4.77	6.32	68,810	12,000	31.0
Hydrogen FCV (2,800 FLH)	88.88	4.77	4.46	68,810	12,000	31.0
	CRF = 0,155		*Lifetime = 8 years*			

Notes. CGV = compressed gas vehicle; CRF = capital recovery factor; FCV = fuel cell vehicle; FLH = full-load hours.

TABLE B3 Data used for calculations in Figure 21

2050	Energy costs	Other tax	VAT	Fuel intensity	Energy price net
Car technology	€/100 km	€/100 km	20%	kWh/100 km	€/kWh
Gasoline ICE	8.11	8.00	3.22	31.2	0.26
Hydrogen FCV (2,800 FLH)	1.73	0.00	0.35	18.0	0.10
Hydrogen FCV (1800 FLH)	2.45	0.00	0.49	18.0	0.14
Methane CGV (2,800 FLH)	4.17	0.00	0.83	32.6	0.13
Methane CGV (1800 FLH)	6.00	0.00	1.20	32.6	0.18
Natural gas CGV	7.50	4.00	3.08	32.6	0.23

Notes. CGV = compressed gas vehicle; FCV = fuel cell vehicle; FLH = full-load hours; VAT = value add tax.

TABLE B4 Data used for calculations in Figure 22

2050	Capital costs	O&M costs	Fuel costs	Investment costs	Distance	Fuel intensity
Car technology	€/100 km	€/100 km	€/100 km	€/car	km/car/Year	kWh/100 km
Gasoline ICE	28.41	7.74	19.33	21,998	12,000	31.2
Natural gas CGV	25.03	6.82	6.82	19,375	12,000	32.6
Methane CGV (1800 FLH)	25.03	6.82	7.20	19,375	12,000	32.6
Methane CGV (2,800 FLH)	25.03	6.82	5.01	19,375	12,000	32.6
BEV	32.47	4.65	5.00	25,137	12,000	11.4
Hydrogen FCV (1800 FLH)	37.64	6.97	2.94	29,140	12,000	18.0
Hydrogen FCV (2,800 FLH)	37.64	6.97	2.07	29,140	12,000	18.0
	CRF = 0,155		*Lifetime = 8 years*			

Notes. CGV = compressed gas vehicle; FCV = fuel cell vehicle; FLH = full-load hours; VAT = value add tax.