Integration of hydrogen storage systems for surplus electricity in the German energy sector

Julia Michaelis, Fabio Genoese, Martin Wietschel
Fraunhofer-Institut für System- und Innovationsforschung ISI,
Breslauer Str. 48, 76139 Karlsruhe, Germany
julia.michaelis@isi.fraunhofer.de
fabio.genoese@isi.fraunhofer.de
martin.wietschel@isi.fraunhofer.de

ABSTRACT

Hydrogen storage systems are one option to better integrate renewable energies into the electricity system. Due to high storage capacities, they can balance times of high wind input by converting surplus electricity into hydrogen that can be stored in underground salt caverns. But similar to other storage technologies, they have to meet the challenge of being economically feasible. In comparison to competing technologies, hydrogen storage systems have the advantage of a versatile storage medium that can be sold on different markets. This paper shows that serving both the electricity and fuel markets has positive impacts on the profitability of hydrogen storage systems. Under favorable conditions characterized e.g. by high shares of renewable energies and high prices for energy carriers, a positive economic result is possible.

1. INTRODUCTION

The increasing share of electricity generated by fluctuating renewable energies requires adjustments in the German energy sector. In future, technologies characterized by high flexibility will become more important because of the need to balance fluctuating electricity generation and consumption. Oversupply situations can occur when the electricity generated by renewable energies and must-run units exceeds the amount needed to satisfy system demand and exports. These situations are likely to occur in the future. One way to avoid surplus electricity is to limit the output of wind turbines or solar parks. Another option that allows the surplus electricity to be used is offered by chemical long-term storage systems that meet the requirements of high storage capacities. Surplus electricity could potentially be used for water electrolysis to produce “green” hydrogen that is stored in underground salt caverns. In addition to its role as a storage medium, hydrogen may also be used directly as a material in the future, if fuel cell electric vehicles (FCEV) achieve a breakthrough in the transport sector. The benefits that result from serving both the electricity and fuel markets and the impacts on the profitability of hydrogen storage systems are analyzed in this paper. It examines whether hydrogen storage systems can be operated economically in two different future energy scenarios. The economic and technical framework that is needed to introduce such hydrogen storage systems was analyzed in the study “Integration von Wind-Wasserstoff-Systemen in das Energiesystem” [1]. This study was completed recently for the German Federal Ministry for Transport, Building and Urban Development (BMVBS). The BMVBS, represented by the German National Organisation Hydrogen and Fuel Cell Technology (NOW GmbH), was involved in the composition of the task and the essential framework conditions. The study is part of the National Innovation Program Hydrogen and Fuel Cell Technology (NIP) that provides a common framework for research projects in this field.

2. STORAGE MEDIUM HYDROGEN

Storing huge amounts of electricity over a long period of time can be done using pumped hydro electrical storage (PHES), adiabatic and diabatic compressed air energy storage ((A)CAES) and hydrogen-based storage systems. Compared to the well-established and cost effective technologies such as PHES and CAES [2], hydrogen storage systems offer the benefit of a much higher volumetric energy density and are therefore more suitable for storing large amounts of electricity for several weeks. If underground salt caverns can be used as a storage option for hydrogen, the storage capacity is 100 times higher than in CAES for the same pressure levels[1]. Therefore, only hydrogen storage systems offer storage capacities that are big enough to integrate the surplus electricity generated during periods of strong wind.

This energy carrier is also versatile enough to serve different markets. Three different options and their synergetic effects are considered for the further use and sale of hydrogen. The reconversion of hydrogen into electricity using a Combined Cycle Gas Turbine (CCGT)[2] makes it possible to offer reserve power and trade electricity. During times of high electricity prices, hydrogen could be reconverted into electricity that can be sold on a spot-market like the European Energy Exchange (EEX). Besides this option, hydrogen can also be used as a fuel for fuel cell electric vehicles and could contribute substantially to reducing emissions in the transport sector in the future. Figure 1 shows all the components of the hydrogen storage system needed to convert electricity into hydrogen and reconvert it or to sell it in the transport sector. The power of the electrolyzer is about 500 MW_{el}. The efficiency losses for fuel production are considerably lower because of the missing step of reconversion that reduces the overall efficiency of the path ‘electricity to electricity’ to 40 %. It must be considered that further losses occur when the hydrogen fuel is transformed into propulsion in the FCEV. However, the overall efficiency of a FCEV using hydrogen made from regenerative electricity is higher than the overall efficiency of an internal combustion engine using conventional fuels [4].

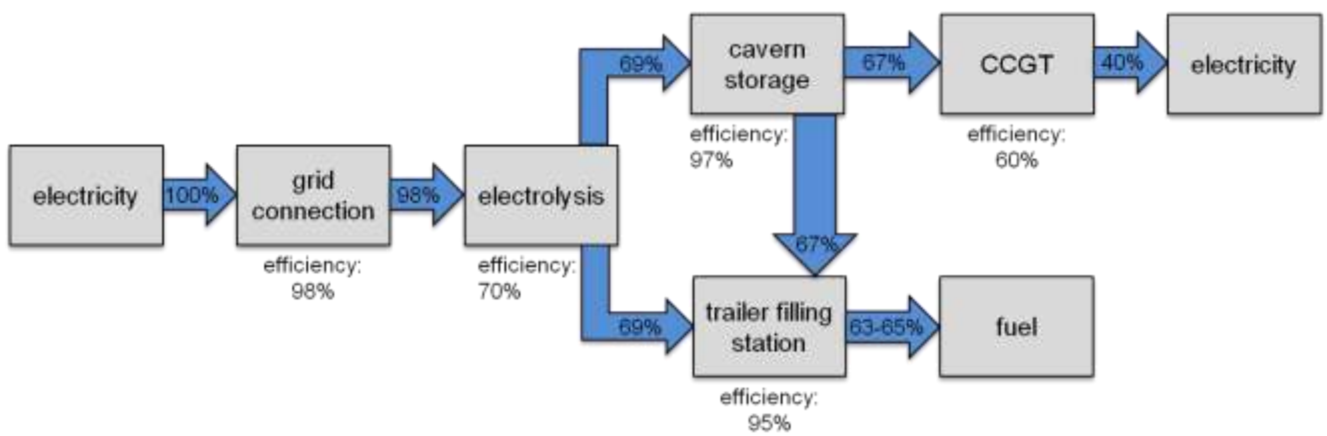

Figure 1: Efficiency chain of the hydrogen storage system considered

[1] At a pressure level of 200 bar, the volumetric energy density of hydrogen amounts to 530 kWh/m³ and that of CAES to 6 kWh/m³, see [3].

[2] Fuel cells are in principle also well suited to reconverting hydrogen to electricity, but showed poorer results for technological and econometric parameters in 2030 in comparison with the CCGT.

3. CALCULATION OF SURPLUS ENERGY

To determine the profitability of a hydrogen storage system in the year 2030 we applied the model PowerACE [5], which models spot and reserve market prices as well as the power plant dispatch of the German electricity sector. Its time resolution is 8,760 hours per year. Compared to earlier versions of the model, we have extended the regional resolution of PowerACE. It is now possible to distinguish three regions within the German system: A north-eastern zone (which has to gather and transport all the electricity fed in by offshore wind parks in the Baltic Sea), a north-western zone (which handles the electricity produced by offshore wind parks in the North Sea), and the rest of Germany. These regions are connected by transmission lines with a limited transmission capacity.
As input parameters, assumptions are needed about the future energy carrier prices and the installed capacities of renewable and conventional plants. These assumptions are taken from scenarios of existing studies. For this analysis, we consider two scenarios: a moderate case, which is based on [6], and an ambitious case, which is based on [7]. The first case is moderate in terms of its renewable share and its fuel prices, whereas the second case can be considered as ambitious with regard to its renewable share. Furthermore, fuel prices increase sharply in the ambitious case.
As PowerACE models the power plant dispatch, it can be used to quantify potential surplus electricity. We define surplus electricity as the amount of electricity with a priority feed-in (e.g. renewable and CHP electricity) that has to be curtailed because it exceeds the sum of the system load plus the export capacity. Due to the regional model approach, we were able to quantify a time series for surplus electricity on a regional level. Figures for the surplus electricity in the year 2030 are given in Table 1. We observed a significant amount of curtailed electricity in the ambitious case. Considering both northern zones, more than 14 TWh would have to be curtailed if no further measures were taken. One option would be to use a hydrogen storage system to absorb the surplus electricity.

case	**zone**	**amount of surplus electricity (GWh)**	**hours with a surplus (–)**	**renewable share that has to be curtailed (%)**
moderate	north-western	250	443	0
	north-eastern	3,700	2,009	3
ambitious	north-western	6,750	2,090	5
	north-eastern	7,500	3,349	10

Table 1: Surplus electricity in the year 2030

PowerACE also computes regional spot and reserve market prices. Whenever renewable or CHP electricity has to be curtailed, the spot market price is 0 €/MWh. This corresponds to the variable costs of a wind turbine. The regional power prices determine the costs of a hydrogen storage system when electricity is purchased for the electrolysis process. Furthermore, these prices determine the income of the system when electricity is sold to the market by converting hydrogen back into electricity in the CCGT process. Hydrogen can also be used in the mobility sector. The specific income for this usage is derived from the following benchmark: An alternative process to produce hydrogen is steam reforming natural gas. Based on the assumptions for the future natural gas price in each scenario, we can calculate the income for a kg H_2 sold to the transport sector. For a better comparability of the figures, we indicate the price at the filling station, which includes transportation[3], processing costs and VAT. The filling station price amounts to 4.80 €/kg (moderate case) and 5.44 €/kg (ambitious case).

4. OPERATION MODES OF THE STORAGE SYSTEM

We distinguish two operation modes of the storage system: a surplus driven mode and a price driven mode. In both cases, the objective is to maximize the contribution margin, i.e. the difference between income and costs. We model the storage operation as an optimization problem. The decision variables of the problem are the power values of the various processes (electrolyzer, cavern input, cavern output, trailer filling station, CCGT plant) and the fill level of the cavern. The main difference between the price driven and the surplus driven modes is the following constraint: In the surplus driven mode, only surplus electricity (e.g. renewable or CHP electricity) can be used to produce hydrogen, whereas in the price driven mode, any electricity can be used as long as it has a positive effect on the contribution margin. The costs for surplus electricity normally amount to 0 €/MWh. It is subject to debate whether this is sustainable for the wind park owners if a vast amount of electricity is to be curtailed. Therefore, we conducted a sensitivity analysis for the costs of surplus electricity where we assumed a price of 80 €/MWh. This corresponds to the expected value of wind power in the year 2020.

5. PROFITABILITY OF HYDROGEN STORAGE SYSTEMS

To evaluate the profitability of the hydrogen storage system, the annual revenues in the spot, reserve and fuel markets are offset against the annual costs. The investment for the entire system including a CCGT plant is about €923 million, in which the acquisition of the electrolyzer accounts for almost half of this investment volume. In comparison, only 10% of this is needed for the cavern. The considered costs include capital, fixed and variable operation and maintenance costs that are estimated for electricity and water as well as for hydrogen compression and drying. The annual capital and maintenance costs are used to determine the net present value[4] and amount to 110 million €/a for the entire storage system including the CCGT plant.

Figure 2 shows the result of a profitability analysis for a hydrogen storage system deployed in the north-eastern zone under the conditions of the ambitious scenario for the year 2030[5]. If the mode of operation allows only the purchase of surplus electricity (‘surplus driven’ case), the costs (shown in blue and green in the lower line) exceed the revenues (shown in black and grey in the upper line) even if the surplus electricity is offered for 0 €/MWh. If the price for surplus electricity is fixed at 80 €/MWh, this results in an increase of the funding gap from €24 million to over €150 million.

[3] We assume a mean distance of 300 km between the hydrogen storage system and the filling station.

[4] The calculations are based on an interest rate of 8% and a technical lifetime of 30 years for the storage system and 20 years for the CCGT.

[5] The economic results vary only slightly for the north-eastern and north-western zones, therefore just one zone is shown as an example.

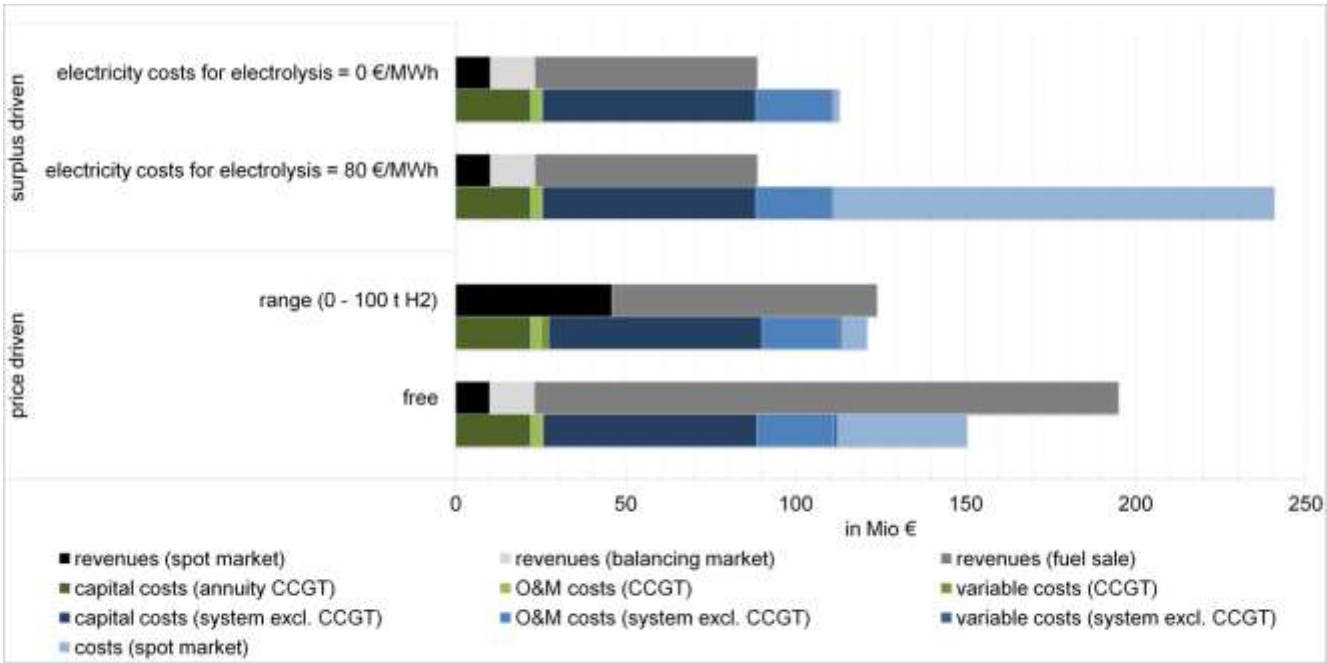

Figure 2: Profitability of a hydrogen storage system in the north-eastern zone in 2030 in the ambitious scenario

A positive overall result - which means the costs of operation are covered - is reached if the constraint allowing only surplus electricity to be used for hydrogen production is removed and replaced by the assumption that an indefinite amount of electricity can be bought on the electricity exchange (‘price driven’ case). Since electricity is no longer limited, the system buys not only the surplus electricity that is offered for 0 €/MWh and therefore always used for hydrogen production, but also additional electricity at times of low prices. As a consequence, the load factor of the system increases. On the other hand, it must be taken into account that purchasing electricity for 0 €/MWh has positive effects on the economic result, because more than half of the purchased electricity is from this source. This, in turn, means that a share of more than 64% of hydrogen is made from regenerative electricity, so that hydrogen production is largely CO_2-free. This plays an important role in the further use of hydrogen for example in the transport sector.

The two price driven cases differ with regard to the maximum amount of fuel that can be sold every day. In the case ‘with range’, 100 t H_2/d is sold, which means an annual profit of €3 million. Removing the limitation of the daily fuel amount sold in the ‘free’ case shows that most of the time, selling hydrogen as a fuel is more attractive than reconverting it and selling it on the electricity exchange market. If there are no limits, more hydrogen can be sold as a fuel, which is more lucrative at most hours of the year than reconverting it or providing reserve power. For this reason, the fuel sales in this case rise to an average daily amount of 220 t H_2 which results in a positive economic profit per year of €44 million. At the same time, the share of hydrogen used for reconversion decreases from 39 to 3%.

In most cases, reconverting hydrogen to electricity has no positive impact on the profitability of the hydrogen storage system. In three of the four cases shown in Figure 2, the costs linked to the CCGT exceed the revenues generated from the reconversion or the provision of reserve power. Apparently, the simulated low spot price implies price spreads that rarely offer incentives to sell electricity on the exchange and that surpass fuel revenues at the same time. But storage technologies with low overall efficiency need very high price spreads between the time of charging and discharging to generate profits. If the CCGT in the optimization model is replaced by a cheaper but less efficient gas turbine, the effects on the profitability are positive. The lower investment and variable costs of the turbine are

below the revenues for reserve power provision, which means that the acquisition of the turbine makes economic sense. The lower efficiency causes reconversion to become unprofitable since this only makes sense where there are huge price differences involved. The combination of a hydrogen storage system and a gas turbine is therefore limited to supplying only the fuel and reserve power markets.
To analyze whether hydrogen produced from surplus electricity will be competitive as a fuel in the transport sector in the future, it is necessary to compare this with other alternative hydrogen production methods. The majority of hydrogen is produced via natural gas steam reforming at present [8], so this method is used as a benchmark for the electrolysis of surplus electricity. It should be considered that this production method is very cost-efficient, but is based on a fossil energy carrier and therefore emits CO_2. If the electricity used for hydrogen production is derived completely or mainly from renewable sources, the CO_2 balance improves. So it should be kept in mind that a purely economic comparison of fossil and (mainly) regenerative hydrogen does not take into account the ecological value of the latter. Other benchmarks show better economic results for hydrogen produced from surplus electricity and are presented in [1].
Based on the simulation results, the hydrogen production costs per MWh_{H2} are determined which allow the costs of operating the storage system to be covered. In the 'surplus driven' case, costs are about 88 €/MWh H_2 if electricity can be purchased for 0 €/MWh and about 213 €/ MWh H_2 if electricity costs 80 €/MWh. The production costs for hydrogen from natural gas steam reforming[6] reach this cost level for natural gas prices of 57 or 152 €/MWh CH_4. These results show that only a sharp rise in the price for natural gas will lead to a situation in which hydrogen from surplus electricity can compete with hydrogen produced via central natural steam gas reforming in terms of price. In the ambitious scenario, a gas price of 39 €/MWh is assumed, which implies that natural steam gas reforming is still the cheaper production method. Looking beyond purely economic aspects, however, it should not be disregarded that using renewable electricity for electrolysis represents a CO_2-free production method and therefore makes a considerably higher contribution to the decarbonization of the transport sector than natural steam gas reforming.
For the consumer, the ultimate criterion is the price at the filling station for hydrogen fuel. This price is composed of production, transport and filling station costs[7] plus a profit margin and value added tax. Figure 3 illustrates these cost elements and the tax for the cases examined. The price at the filling station is weight-specified, so the costs are expressed in €/kg H_2 as well. The costs that occur for the production and distribution of hydrogen from natural steam gas reforming serve as a reference value. Profit margins and a possible accruing energy tax are not considered. The production costs are set so that the operating costs of the hydrogen storage system are covered, but no profits are generated. Because the transport and filling station costs are the same for both electrolysis and natural steam gas reforming, differences arise only from variations in production costs or value added tax. For the 'surplus driven' case, the cost assumption for the surplus electricity has a large influence on the costs. Assuming surplus electricity costs of 0 €/MWh results in costs of 6.37 €/ kg H_2 at the filling station, which are more than 17% higher than the costs of the reference method. If, on the other hand, surplus electricity costs of 80 €/MWh are assumed, the costs at the filling station amount to 11.32 €/kg H_2, which is more than double the cost of the reference method. For the 'price driven' cases, costs at the filling station are 4.77 €/kg H_2 ('free' case) and 5.34 €/kg H_2 ('with range' case). In these cases, therefore, the reference cost value for hydrogen from natural steam gas reforming can be undercut.

[6] The costs for hydrogen production via central natural steam gas reforming are based on a plant size of 844 MW H_2, following [4].
[7] Hydrogen is transported in trailers with pressure cylinders of 500 bar and a capacity of 1 t H_2. Cost assumptions for transport and filling stations are based on [4].

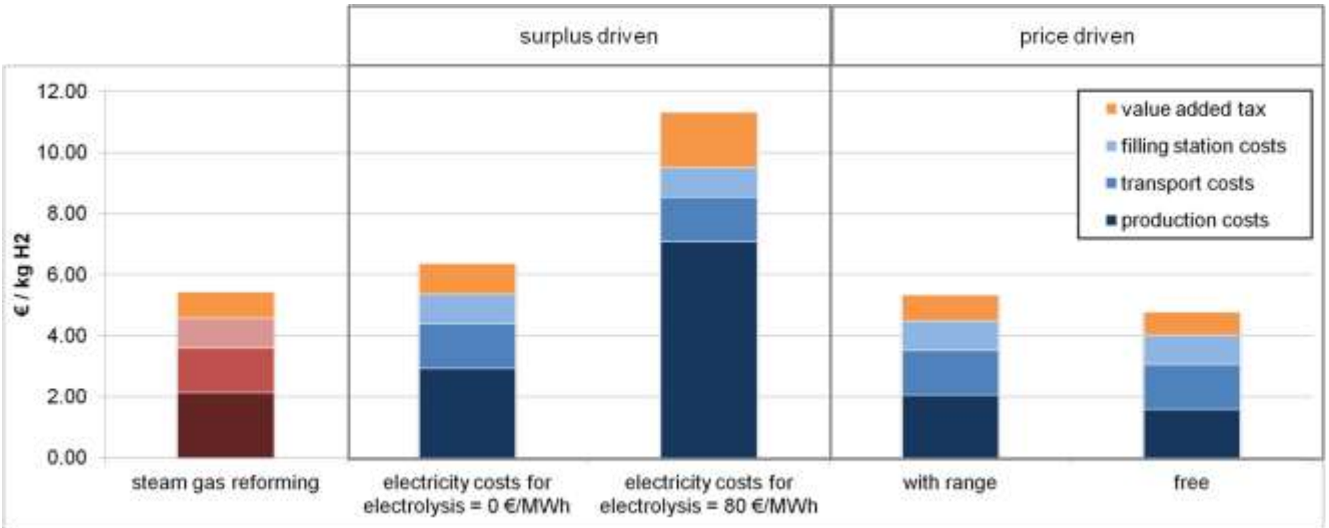

Figure 3: Hydrogen fuel costs at the filling station in the north-eastern zone in 2030 in the ambitious scenario

6. CONCLUSION

In a future energy system with high shares of fluctuating renewable energy, the challenge of matching electricity production and demand will grow. Hydrogen storage systems could help here by using surplus electricity for water electrolysis to produce ‘green’ hydrogen that is stored in underground salt caverns for some weeks and later sold on the electricity and fuel markets. The analysis revealed that it is possible to cover the costs of such operations under favorable conditions that are characterized, e.g. by an ambitious expansion of renewable energy capacities and high fuel prices for oil, gas and coal.
The simulations indicate that the amount of surplus electricity is the main factor influencing the profitability of the storage system. This is because the formation of spot prices and the load factor depend directly on the amount of surplus electricity. In the moderate scenario, the maximum zonal surplus is 3,700 GWh, which constitutes just 3% of the zonal production of renewable energy. A cost-covering operation cannot be achieved then if the price of hydrogen fuel at the filling station is based on the cost of producing hydrogen via central natural steam gas reforming. In this context, it must be considered that a cheap fossil hydrogen production method is taken here as a benchmark for regenerative hydrogen. Other benchmarks induce a better economic result and are presented in [1]. In the ambitious scenario with higher shares of renewable energy capacities, the amount of surplus electricity is 7,500 GWh, so 10% of renewable electricity production could not be used without storage systems and would be curtailed. Due to the higher amount of surplus electricity, the load factor and the economic result of the hydrogen storage system improve in this scenario.
Comparing the ‘surplus driven’ and the ‘price driven’ cases makes it clear that the price for hydrogen from steam gas reforming cannot be undercut in the first mentioned case. If the benchmark price of 10 €/kg H_2 at the filling station is taken as a reference value, it would be possible to cover the operating costs of the hydrogen storage system with free or cheap surplus electricity costs, see [1]. In the ‘price driven’ case, the hydrogen storage system can compete with the price of fossil hydrogen and additionally shows that high shares of renewable electricity of at least 64% were used for electrolysis. This means that hydrogen produced mostly from renewable sources can be offered at a competitive price. However, certain framework conditions are necessary for such results, e. g. high shares of renewable energies in the energy system.

In summary, it could be observed that the fuel market is the more lucrative sales option for hydrogen because of the higher overall efficiency and higher revenues from fuel sales. Depending on the scenario, 60 to 97% of the hydrogen is sold as fuel. In comparison to this, the revenues from reconverting hydrogen to electricity are much smaller due to the lower overall efficiency and lower electricity price. However, it should be noted that covering the operating costs is only possible for two hydrogen storage systems in the ‘price driven’ case based on steam gas reforming as the benchmark for the revenues from fuel sales. These two systems could cover 27% of the assumed hydrogen fuel demand in 2030. The use of other hydrogen production methods might be necessary to meet the entire fuel demand. Furthermore, increases in hydrogen demand could afford the construction of a new hydrogen infrastructure in the long term that is linked to high investment sums. First activities that foster the construction of a nationwide hydrogen infrastructure can be observed within the initiative H_2Mobility.

The analysis did not cover the direct feed-in of hydrogen into the natural gas grid neither the methanation nor sales options in the gas sector (power-to-gas). Via direct feed-in or methanation of hydrogen, the gas could be stored in the gas grid and transported to the consumers. The advantages of the existing grid infrastructure must be compared to the additional costs and efficiency losses associated with methanation. The evaluation of these concepts and extending the model are currently being considered in ongoing scientific research.

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