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H_2 in the gas network and interaction with gas engines

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Abstract

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Summary

Around one-sixth of Germany's primary energy demand is currently met by renewable energy [1]. In order to achieve the revised German climate targets (greenhouse gas neutrality by 2045) as judged by the Federal Constitutional Court in August 2021 (see Figure 1), it is an urgent necessity to increase the share of renewable energies significantly.

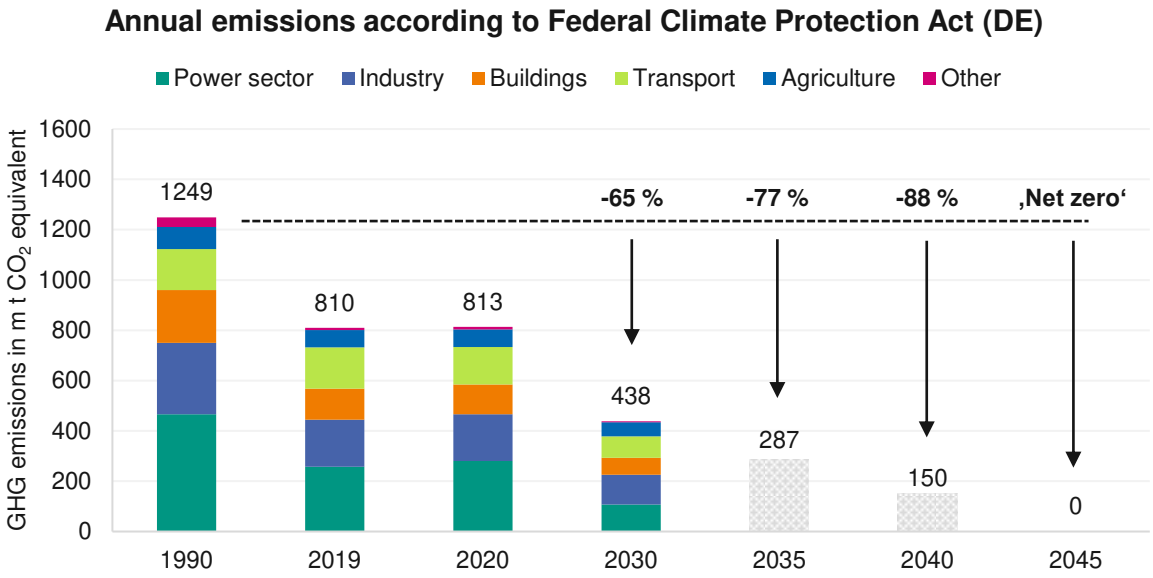

Figure 1: Annual emissions according to Federal Climate Protection Act (Germany). DVGW-EBI, own illustration based on [2]

Renewable gases such as methane and hydrogen thereby can play an important role, since the majority of energy consumers in the industrial, commercial, heating and power generation sectors are already connected to the gas grid. From both a technical and an economic point of view, the natural gas grid offers ideal conditions for receiving, storing, transporting and distributing climate-neutral gases to all sectors. As of today, biomethane and synthetic methane can be easily fed into the existing gas infrastructure and achieve significant greenhouse gas emission reductions, especially in sectors where oil and coal are still used today. On the other hand, the admixture of hydrogen in the existing natural gas grid is limited or requires a stepwise adjustment of both gas infrastructure and end-users. According to [3] especially underground gas storage facilities, CNG vehicles (CNG: compressed natural gas), gas turbines, stationary gas engines and industrial or domestic gas appliances require further investigation when adding higher amounts of hydrogen into the grid. For example in accordance to UN ECE R 110 [4] and EN 16723-2 [5] the hydrogen tolerance of the legacy CNG vehicle fleet is limited by the H_2 tolerance of the tank system and fuel specifications to a maximum value of 2 vol.-% H_2. Therefore, CNG filling stations must ensure a hydrogen content of below 2 vol.-% for CNG dispensing. Nevertheless, various studies showed that the admixture of up to 10 vol.-% H_2 is feasible for large parts of the gas grid [6–9].

The political discourse on hydrogen is currently having an intensive impact in all sectors with more and more end-users planning to switch to hydrogen in short term. The first industrial companies are preparing to defossilize their processes using hydrogen, districts are being supplied with electricity and heat via fuel cells or hydrogen CHP plants, and finally hydrogen

is increasingly apparent in public transport. Subsequently, gas qualities with higher and fluctuating hydrogen contents may be present in the transport and distribution gas network in the medium and long-term perspective. This requires measures to adapt infrastructure and end-users like gas driven mobility or stationary gas engines to higher hydrogen tolerances. However, a detailed techno-economic assessment of different concepts for dealing with increasing hydrogen contents in the gas grid with regard to gas vehicles and stationary gas engines has not been carried out so far.

Therefore, in this study five different transition scenarios from today to a defossilized gas grid in 2050 were analyzed, considering different hydrogen/methane mixtures, that are in accordance with the (former) German climate goals (GHG neutrality by 2050)[1].

- 100 vol.-% renewable methane by 2050
- 0-2 vol.-% hydrogen, 98 % renewable methane by 2050
- 0-10 vol.-% hydrogen, 90 vol.-% renewable methane by 2050
- 0-30 vol.% hydrogen, 70 vol.% renewable methane by 2050
- 100 vol.-% hydrogen by 2050

In order to identify the most cost-effective transformation path, the gas production costs as well as the required technical adjustments and the resulting adjustment costs for gas infrastructure and end-users (with the focus on road mobility and stationary engines) were assessed regarding an increased and changing hydrogen concentration in the natural gas grid as well as an ambitious CNG vehicle fleet ramp up (Increasing from about 100,000 vehicles today to about 12 million vehicles in 2050). Therefore, for each path a quantitative cost structure was defined in order to determine the corresponding macro-economic costs and to identify a cost-optimal transformation pathway for gas infrastructure and the associated end-users in Germany with an outlook on Europe (see Figure 1).

[1] It should be noted, that at the time this study was processed, the former climate targets under the German Climate Protection Act of 2019 were valid (greenhouse gas neutrality by 2050). The considerations in this study therefore refer to the now outdated greenhouse gas reduction targets.

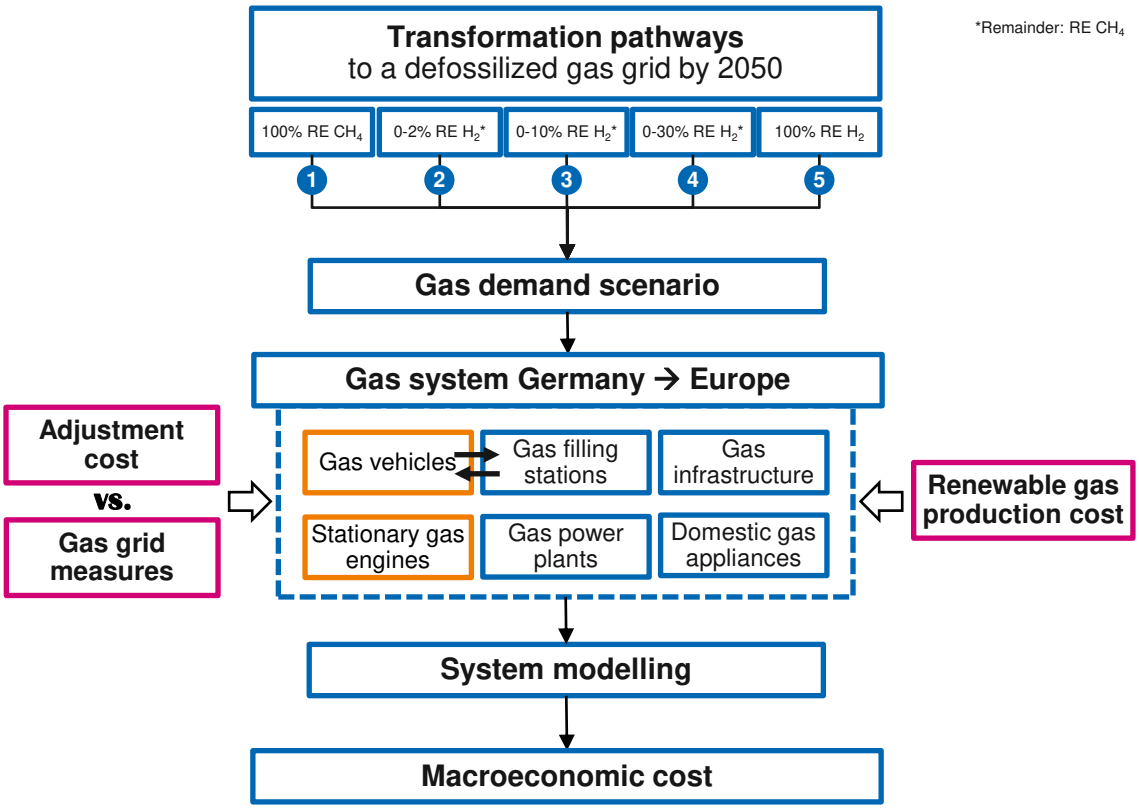

Figure 2: General approach to determine cost-optimal transformation pathways for gas infrastructure and associated end-users (with focus on gas driven mobility and stationary engines)

As mentioned before, the current regulations in Germany enable a hydrogen blend of 10 vol.-% in the **gas infrastructure** wherever there are no restrictions due to specific hydrogen sensitive elements of the gas grid or gas applications. In order to increase the H_2 compatibility of the gas infrastructure to up to 10 vol.-% the replacement of cast iron pipelines and process gas chromatographs is required. Additionally, components of underground gas storages have to be adapted. For higher and varying amounts up to 100 vol.-% hydrogen, the replacement of compressor stations and gas measurement technologies is required.

In addition to the gas infrastructure, the following gas applications were considered:

- Gas mobility (CNG vehicles),
- Stationary engines (CHP plants),
- Gas filling stations as well as
- Gas power plants and domestic gas appliances

The **vehicle** modeling showed that flexifuel operation is feasible in principle for all defossilization scenarios. The additional costs to be expected increase with the maximum hydrogen content and are essentially determined by the tank system. Costs for the gas tank and the tank valve account for the largest share of additional costs in the blend scenarios with 0-30 vol.-% and 0-100 vol.-% hydrogen while in the case of 0-10 vol.-% hydrogen no major adjustments are expected to be required to the tank. Due to the expected range loss of 60 % to 79 % depending on the pressure of the tank system in combination with a loss of propulsion power of 27 %, a retrofit in the 100 % H_2 scenario is not considered technically feasible. The tank assessment also shows that a 700 bar system is required in the tank for passenger cars to meet

the range requirement. For light-duty and heavy-duty applications, a tank system of at least 350 bar is recommended. Due to the high cost of the tank system and the expected fuel savings, the use of hybridized drives is still recommended. Thus, despite additional components, 2nd Generation vehicles are expected to have lower overall costs than comparable vehicles of the previous generation. Additional components such as hydrogen sensors, fuel sensors and flame filters were identified as necessary for the 30 vol.-% as well as the 100 vol.-% scenario. However, the costs due to these additional components are estimated to be less than 200 EUR per vehicle. The majority of the engine, with the exception of the fuel-carrying components, is classified as unproblematic across all scenarios. In total, costs for making vehicles compatible add up to 3,688 mEUR to 141,837 mEUR depending on the hydrogen scenario.

In contrast to gas vehicles, for **stationary gas engines** the tank system is not a cost-intensive component. The necessary modifications therefore mainly affect the turbocharging system and the fuel supply. The most cost-intensive component identified in this analysis is the compressor unit, which is required for port fuel injection (PFI) or direct injection (DI) systems in combination with low- or medium-pressure gas lines. This applies in particular to small and medium-sized plants. Costs for retrofitting existing plants add up to 137 mEUR for the 0-10 vol.-% hydrogen scenario and 4,350 mEUR for the 0-100 vol.-% hydrogen scenario. Oncosts for making new plants compatible with higher blends of hydrogen add up to 125 mEUR to 7,627 mEUR until 2050, again depending on the hydrogen scenario.

For **filling stations** the cost are dominated by compressors and high pressure storage. Since the existing refueling infrastructure is insignificant, an ambitious ramp-up is required to serve the assumed, increasing gas demand in mobility. The adjustment costs are highest for the 0-100 vol.-% H_2 scenario since a switch from CNG technology (200 bar) to H_2 technology (700 bar for passenger cars, 350 bar for trucks) is required, causing a strong increase in both investment cost and operational expenses. The oncosts for filling stations (compared to pure methane scenario) add up to 437 mEUR for the 0-10 vol.-% H_2 scenario, 1,251 mEUR for the 0-30 vol.-% H_2 scenario and 57,285 mEUR for the 0-100 vol.-% H_2 scenario.

Gas power plants were evaluated beside gas mobility and CHP applications on a high-level basis. Usually, the existing gas turbines have a limited hydrogen-tolerance of 1 - 5 vol.-%. The essential technological challenge is the higher flame velocity. With increasing hydrogen concentration, the flame becomes more instable, which results in a higher risk of flame extinction. If the flame of the power plant extinguishes, it triggers an unplanned shut off. Further, an increasing hydrogen concentration reduces the ignition delay time. Therefore, the adaption or the exchange of gas turbines is necessary for the transformation

Domestic gas appliances (gas heating systems, gas boilers, space heaters and gas ovens/stoves) were also evaluated beside gas mobility and CHP applications on a high-level basis. Usually, domestic gas appliances are able to tolerate H_2-concentrations of 20 vol.-%. However, research projects showed that if more than 30 vol.-% H_2 is added, the functionality of the appliances is not guaranteed. The adaption of existing appliances is not economic as the costs for adaption and recertification are higher than the exchange costs. Manufacturers state that new gas boilers can be adapted for the use of pure hydrogen in the future.

The macro-economic evaluation of the considered transformation paths and end-user adjustments shows no significant difference in total costs (see Figure 3). With maximum oncosts of 70 billion EUR or 2.4 % (0-100 vol.-% H_2 scenario) all transformation paths have a similar economic feasibility. This is mainly due to the increasing cost savings in gas production, when substituting methane with hydrogen. Thus, compensating the higher adjustment costs for end-users and infrastructure.

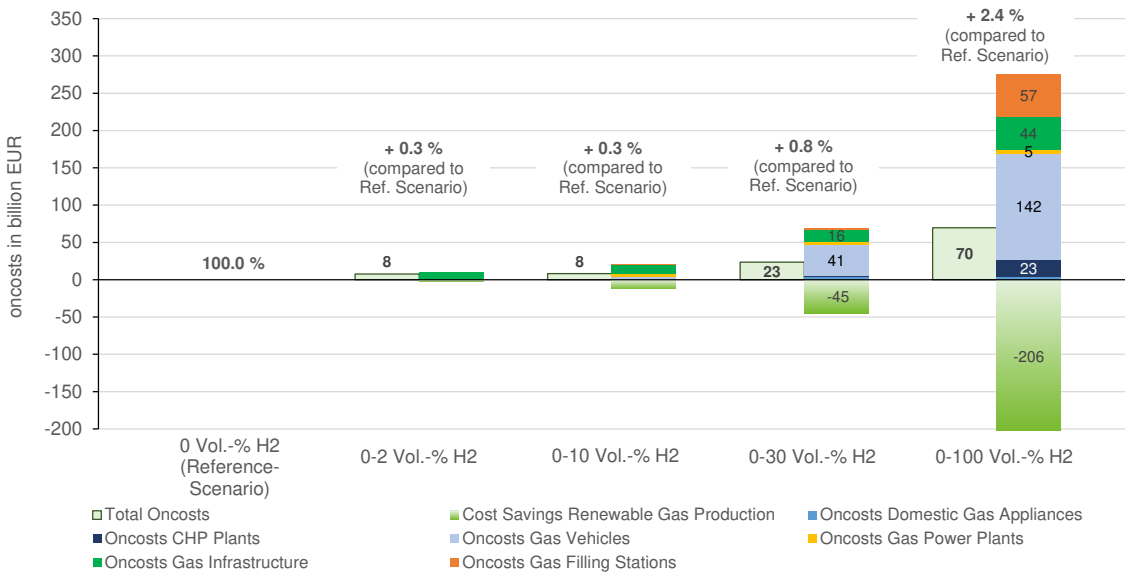

Figure 3: Scenario comparison of oncosts (Germany) compared to pure methane scenario (2022-2050). Source: DBI, own illustration

In the pure methane reference scenario, no H_2-related adaptions of the gas infrastructure or applications are required. With higher hydrogen grid contents the renewable gas production costs drop significantly, while the adjustment costs for gas infrastructure (including associated gas appliances) and especially gas vehicles and gas engines are increasing. In scenarios 0-30 vol.-% H_2 and 0-100 vol.-% H_2 the major share of the oncosts is accounted by gas vehicles (41 billion EUR or 142 billion EUR) and gas engines (1.0 billion EUR or 22.6 billion EUR), while for gas infrastructure and associated gas applications like domestic gas appliances, gas filling stations or gas power plants the total oncosts (26.1 billion EUR or 110.1 billion EUR) are compensated by lower gas production costs (- 45 billion EUR or - 206 billion EUR).

Scaling the results to Europe shows similar results (see Figure 4). In this case, the 0-100 vol.-% H_2 scenario requires 398 billion EUR additional costs compared to the pure methane scenario, which corresponds to a maximum cost difference of only 2.5 %.

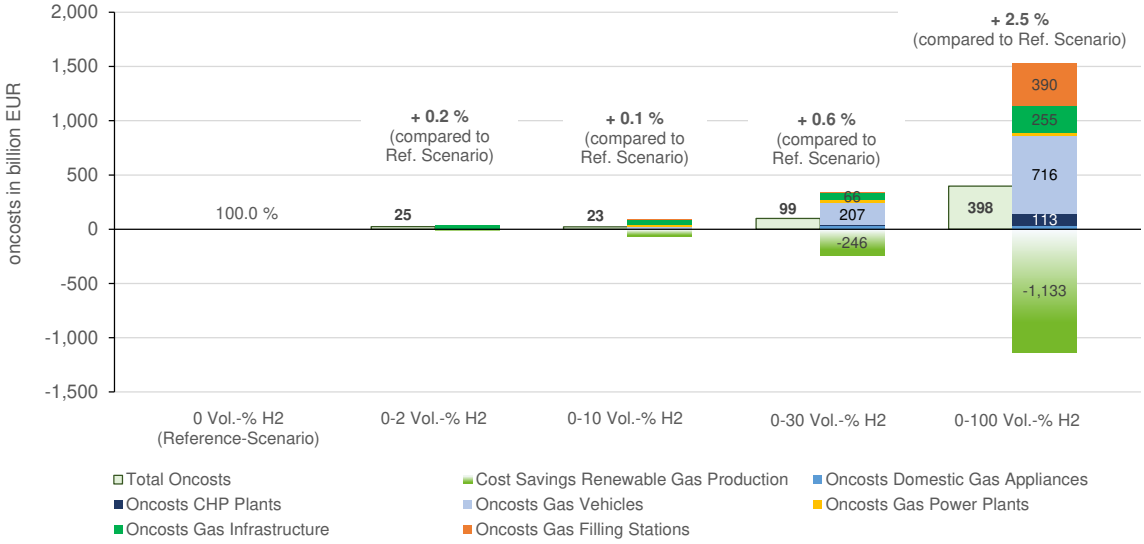

Figure 4: Scenario comparison of oncosts (Europe) compared to pure methane scenario (2022-2050). Source: DBI, own illustration

In addition to the adaptation of end-users, the separation of hydrogen via membranes and the conversion of hydrogen to methane through methanation were investigated. Therefore, all CNG filling stations were equipped with methanation or membrane units in order to ensure a maximum hydrogen concentration of 2 vol.-% in the gas input flow. Figure 5 provides an overview of the sensitivities considered.

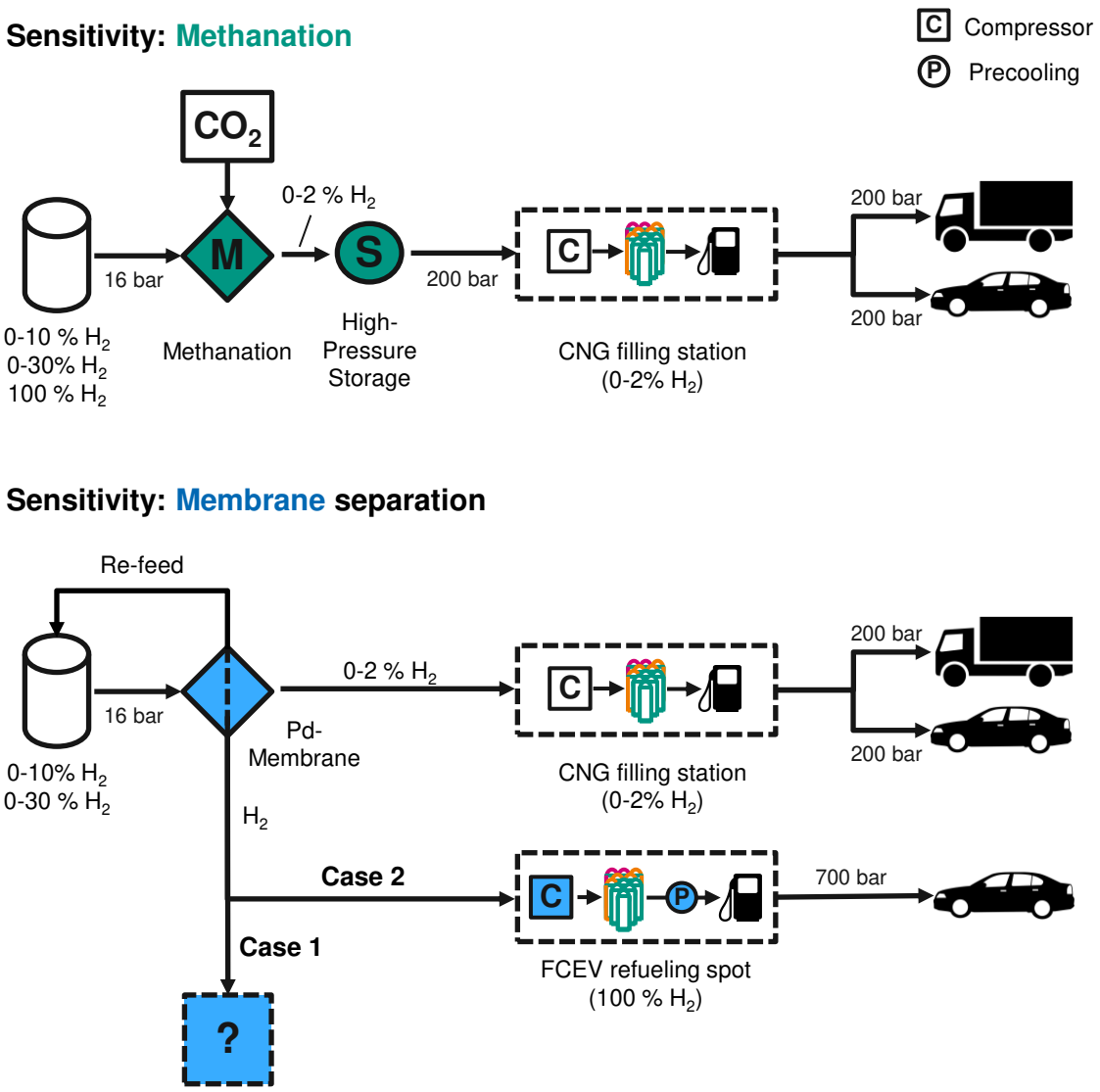

Figure 5: Sensitivity analysis: methanation and membrane separation at filling stations. Source: DVGW-EBI, own illustration

In case of methanation, cost benefits for 0-30 vol.-% H_2 scenario and 0-100 vol.-% H_2 scenario could be identified (see Figure 6). In 0-30 vol.-% H_2 scenario the adjustment costs for filling stations and gas mobility decrease by about 13 billion EUR, thus lowering the total oncosts compared to the pure methane scenario from 24 billion EUR to 11 billion EUR. In 0-100 vol.-% H_2 scenario the adjustment costs for filling stations and gas mobility are reduced by 156 billion EUR, leading to cost savings of about 85 billion EUR (- 2.9 %) compared to pure methane scenario.

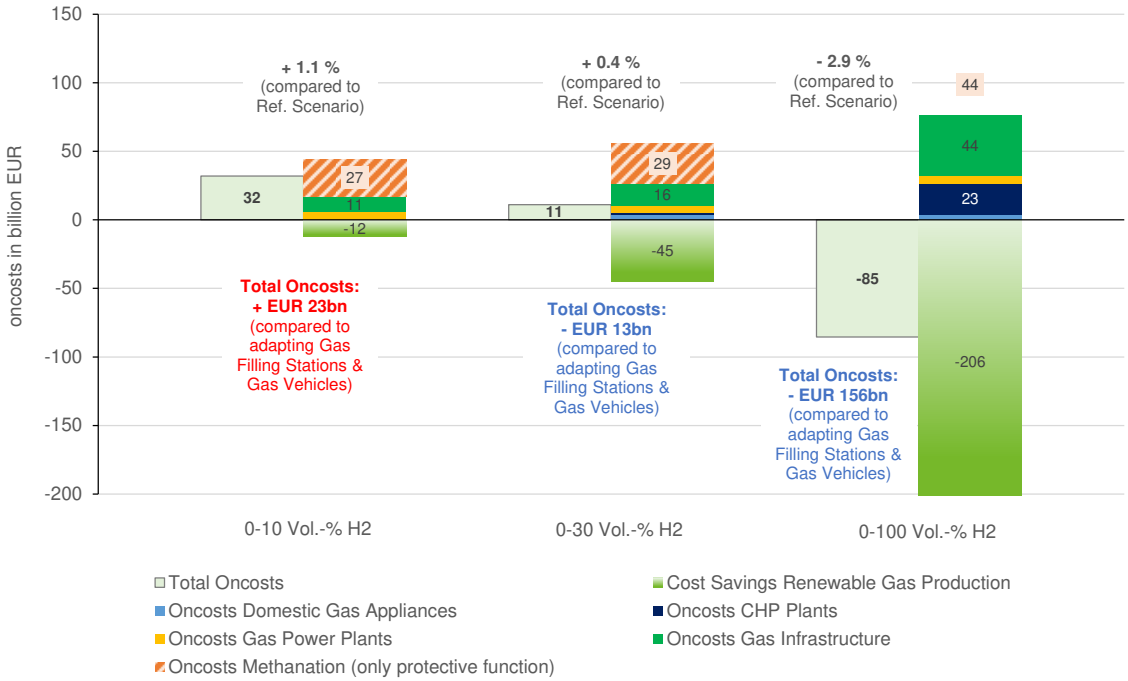

Figure 6: Total oncosts of the whole gas system under consideration of methanation compared to reference scenario (2022-2050). Source: DBI, own illustration

For membrane separation, two use-cases were investigated:

- **Case 1**: Separation of hydrogen without further use
- **Case 2**: Separation of hydrogen and use as fuel for FCEV in dual fuel filling stations.

In the 0-10 vol.-% H_2 scenario both cases lead to higher oncosts compared to the adjustment of vehicles and filling stations (see Figure 7 and Figure 8). Especially in case 2 the oncosts for using membrane separation instead of adjusting vehicles and filling stations are significantly higher (114 billion EUR). This is due to the required amount of hydrogen at dual fuel filling stations and the necessity to achieve H_2 enrichment by increasing the gas input flow of the membrane unit. Since the capacity and costs (investment and operating expenses) of the membrane unit are directly linked to the underlying gas input flow, low hydrogen grid concentrations will lead to high separation cost and should be avoided.

In 0-30 vol.-% H_2 scenario the cost savings (compared to filling station and vehicle adjustment) for membrane case 2 (Figure 8) are similar to those of the methanation case (- 10 billion EUR), thus lowering the oncosts compared to the pure methane scenario by 42 % from 24 billion EUR to 14 billion EUR. In membrane case 1 (see Figure 7), the cost savings are about 7 billion EUR higher. However, since in membrane case 1 no hydrogen use cases and therefore no hydrogen enrichment has been investigated, the results are not comparable.

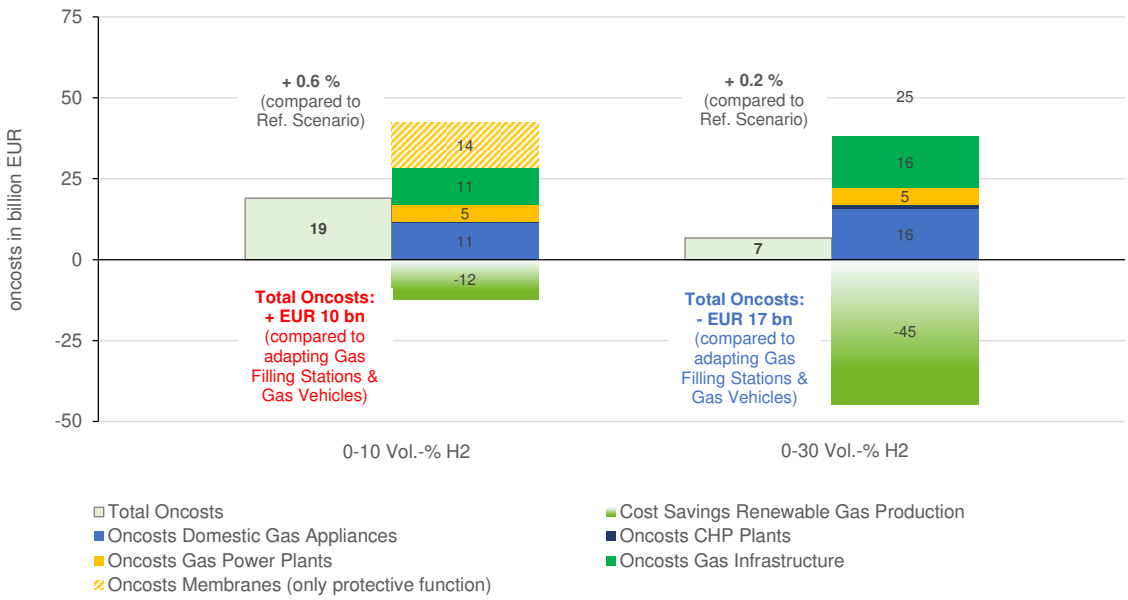

Figure 7: Sensitivity analysis: Total oncosts of the whole gas system under consideration of membrane separation (Case 1: only protective function) compared to reference scenario (2022-2050). Source: DBI, own illustration

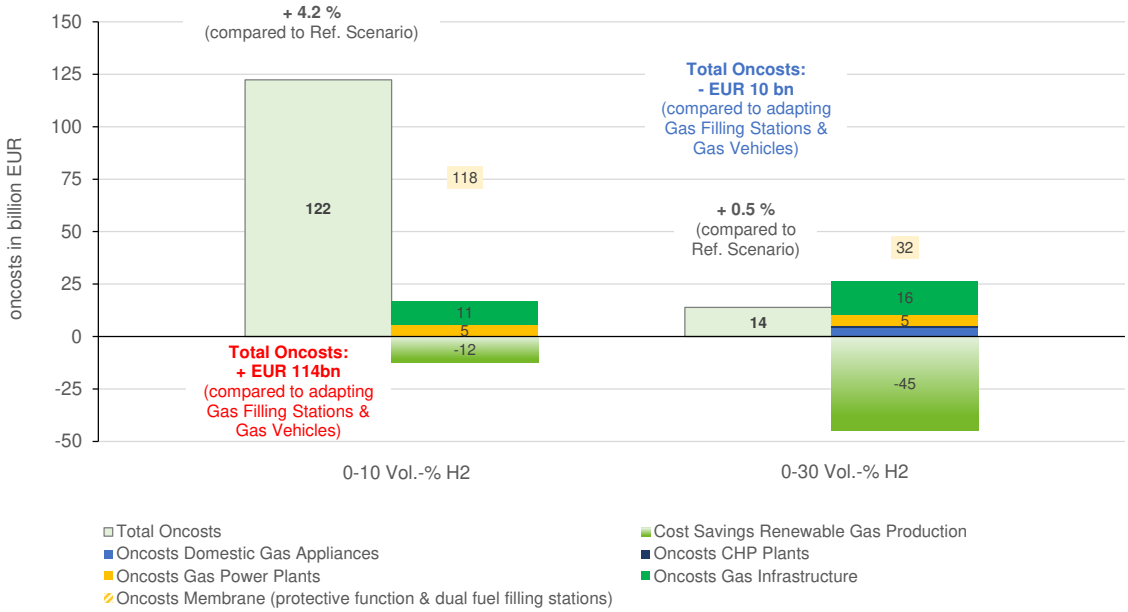

Figure 8: Sensitivity analysis: Total oncosts of the whole gas system under consideration of membranes (Case 2: dual fuel filling station) compared to reference scenario (2022-2050). Source: DBI, own illustration

Besides the separation and conversion of hydrogen also various gas grid control measures were examined that could protect users from excessive hydrogen concentrations in the gas grid, such as buffering the hydrogen or optimized routing of the hydrogen flow. It turned out that these measures would be technically suitable, but, unlike membranes or methanation, would have to be adapted individually for each grid structure. Therefore, it is not possible to calculate total costs for the entire gas infrastructure in Germany. For this reason, gas grid control measures could not be considered in the sensitivity analyses of the system modelling.

Conclusions

With a maximum cost difference of 2.4 % for 0-100 vol.-% H_2 scenario compared to the pure methane scenario, the macro-economic evaluation shows no significant difference in technical and economical feasibility between the different transformation scenarios. However, there are differences in the allocation of costs regarding gas vehicle and gas engine adjustments on the one hand, and gas infrastructure adjustments on the other hand. Therefore, higher hydrogen grid contents lead to a significant drop in renewable gas production costs, shifting the major share of the oncosts from the gas infrastructure side to the vehicle and gas engine manufacturers. Methanation and membrane separation are an economic alternative to vehicle and filling station adjustments in 0-30 vol.-% H_2 and 0-100 vol.-% H_2 scenario. However, in this case the oncosts are fully attributed to the gas infrastructure side.

It should be noted that the macroeconomic analysis does not provide any information on the time required to implement the respective transformation pathways. Regarding the limited remaining global CO_2 budget, fast applicable GHG abatement options must be prioritized. To assess the feasibility of the transformation pathways in terms of time, further research is required that addresses the bottlenecks of the respective transformation pathways (e.g. import and supply of sufficient quantities of renewable methane or adaptation of the existing gas infrastructure and the connected users to higher H_2 concentrations).

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