Hydrogen in Gas Grids

A systematic validation approach at various admixture levels into high-pressure grids

D5.3

Intermediate report: key findings on potential and enablers

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Executive Summary

Introduction

This report contains the work caried out in Task 5.3, *Evaluation of results and compilation of recommendations,* so far. In particular, the results obtained with the help of the techno-economic model developed in this project are presented and evaluated here. Section 3 describes all results produced. The section is divided into sensitivity analysis (section 3.1), techno-economic modelling of the membranes (section 3.2), results not considering separation technology (section 3.3) and finally the results considering separation technology (section 3.4). Finally, key findings are presented and summarised in section 4.

Key findings

Main conclusion of the techno-economic modelling of the membranes shows that at large scale, the total CAPEX can be decreased to 13,812 €/m^2. This is approximately 37% of the cost when compared to lab scale production.

As per OPEX, a calculation of the cost for 1 Nm^3/h of hydrogen is to be expected to be around 0.95 €/Nm^3 of H_2. This cost being strongly dependent on (the currently very volatile) price of energy (mainly electricity)

The costs for transport of hydrogen computed with the model developed in this project are in the same order of magnitude as suggested by other studies and are therefore considered plausible:

- approx. **3-5 €/MWh/1000km** without consideration of membranes
    - The transport of hydrogen at high pressure in pipelines is by far the most cost-effective option when membranes are not considered. The low volumetric energy density speaks against large-scale transport by trucks.
- approx. **11 - 47 €/MWh/1000km** considering membranes at all city gates
    - the choice of the cost-optimal transport medium is no longer quite so clear. LH2 is considered to be of little use in this case (both by truck and by ship) in a European context. This leaves transport by truck in the form of compressed gas or as LOHC.

    - Transport in summer via pipelines tends to be somewhat cheaper than transport by truck, but only if the quantities are appropriate. However, if larger quantities of hydrogen have to be transported, as in winter, the truck seems to be more suitable. The investments required for membranes are simply too high and have a correspondingly negative effect on transport costs.

- approx. **7 - 11 €/MWh/1000km** considering the targeted use of membranes
    - the transport of hydrogen through a converted natural gas grid can make sense through the targeted use of membranes. It can not only be competitive, but even the most cost-effective solution. However, it is difficult to make a final statement, as the result depends on many local conditions, such as the demand for natural gas and/or hydrogen or the locally permitted hydrogen concentration in the natural gas grid.

it is currently hard to give an exact figure of what the conversion of the entire existing European gas grid would cost. The regional differences in supply and demand, both for natural gas and hydrogen, are currently so significant that only a local analysis of the situation really makes sense and allows a well-founded statement.

Outlook

This first set of key findings on the potential and enablers from Task 5.3 will be further elaborated with the other partners of this WP in the coming period. The aim will be to compile a set of recommendations that will provide a basis for decision-making for all stakeholders involved. A first direction will be given by the MS20 report in M39. This in turn will be further elaborated into D5.4, which will conclude the activities in WP5 in M42.

1 Objective

The main objective of this deliverable D5.3 is to present the results of the techno-economic modelling according to D5.2 and the cases described within it. Further, key findings on potential and enablers in a pan European context are described.

The specific results of this deliverable are classified as follows:

- Sensitivity analysis of the techno-economic model
- Techno-economic analysis of the membranes developed in HIGGS
- Determine levelized costs for H_2-transport for different cases
  - Not considering separation technology
  - Considering separation technology
- Determine the H_2-concentration along the modelled grid where of interest
  - Not considering separation technology
  - Considering separation technology

2 Introduction

In the HIGGS project, an experimental R&D platform has been built to conduct tests on the integrity of natural gas transmission network infrastructure under the influence of hydrogen admixture. The testing loop includes state-of-the-art components and materials of gas pipelines and is designed to work up to 80 bar with various blending levels but also pure hydrogen. A hydrogen purification prototype based on membrane technology for the separation of H_2/CH_4 on behalf of different end-use applications is also integrated in the design.

In addition to the construction and commissioning of the plant, as well as carrying out and analysing various tests (e.g. varying the H_2 concentration and using different pipeline steels), further research is carried out with regard to legal, regulatory, technical and economic aspects of the blending of hydrogen into the existing gas grids.

In WP5, *Techno-economic modelling and validation, enablers and interoperability*, the main objective is to develop operational strategies and business cases for grid operators and to illustrate how hydrogen blending in the high-pressure gas grid can contribute to the overall goals of decarbonising the European energy system. Moreover, the influence of higher H_2 fractions on the economics of the gas transport value chain will be assessed in the project and compared to other common methods, considering gas producers, transport companies up to delivery to the gas distribution networks. For this purpose, a numerical model will be compiled for representative cases in Europe to describe technical operation and business impacts. The model will allow analysing the different technological adaptions of the grid, which strongly depend on the blending level, as well as the operational strategies for the future grid with hydrogen injection.

This report contains the work caried out in Task 5.3, *Evaluation of results and compilation of recommendations,* so far. The Task is led by OST (formerly HSR) and runs form month 20 to 42 of the project lifetime. Project partner participating are TECNALIA and FHa.

The cases, described in detail in D5.2 and briefly refreshed in this report, have been calculated and evaluated. Further, the sensitivity of the techno-economic model to some key economic parameters Is investigated. The set of results is further supplemented by the techno-economic analysis of the membranes developed in HIGGS.

The purpose is to present the results for the modelled network section. It is achieved by comparing the cases amongst each other by using the metric of levelised costs for hydrogen transport in €/MWh/1000km and putting it into perspective with other means of transport. Eventually, a few key findings are derived from these results that put the work in a pan-European perspective.

Disclaimer: The results presented in this report are based on a section of the European gas network, which is fed with gas coming from the east. At the beginning of the modelling and well into the work package, the authors of the report did not foresee a complete gas supply stop from the east. However, the model used here is based on a blend of pure CH_4 and H_2. Therefore, gas quality (or gas origin) is of no interest in this model respectively in the results. Due to limited resources, it was no longer possible to model a new gas network section and define new cases. MEGAL and TENP may not be working under the same capacity now, but it is still a representative study for the impact of retrofitting a transmission grid. Despite this development, the results of the techno-economic modelling can be put into an overall European context.

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3 Results of techno-economic model

The baseline for modelling different cases was already set in D5.1 (section 4). This report described different hydrogen blending scenarios, the use hydrogen separation technologies, operation strategies of TSOs and economic aspects to be considered. Possible future scenarios for hydrogen transport in natural gas grids were defined according to the main findings, in a first step not considering separation technologies, but including them later.

All these cases are also described in detail in D5.2 and are briefly refreshed in this report from section 3.3 onwards, where they have been calculated and evaluated. Further, the sensitivity of the techno-economic model to some key economic parameters Is investigated in section 3.1. The set of results is further supplemented by the techno-economic analysis of the membranes developed in HIGGS.

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3.1 Sensitivity analysis of techno-economic model

As you can be seen in Table 1, economic factors needed for the economic part of the model vary a lot in literature. This was further confirmed by a survey amongst members of the external advisory board when asked what values they use for their investments. Basically every organisations or country uses different values. Hence the questions arise:

1. How accurate those figures need to be in order to gain representative results?
2. What are the effects on the results when those values vary?

Table 1: Variation of economic parameters in literature

Cost parameter	Unit	EHB [12]	GASUNIE [7]	James et al [8]
Electricity price / Energy price	€/MWh	40 – 90	114.2	42.7
Interest rates	%	5 – 7	N/A	8 12, 26.6[1]
Amortisation period	Years	15 – 33 30 – 55	N/A	33

In order to answer these questions a sensitivity analysis was conducted. For this purpose, the following base values were established for the three most important factors according to Table 2

Table 2: Base values for sensitivity analysis

Cost parameter	Unit	Pipelines	Compressors	City gates
Electricity price / Energy price	€/MWh	N/A	50	50
Interest rates	%	6	6	6
Amortisation period	Years	30	15	15

In a second step, two factors were left constant while the third was varied by ±50 % in 10 % increments. Finally, it was calculated how the levelized costs for H2-transport changed relative to the baseline value.

[1] Capital recovery factor, corporate tax rate

3.1.1 Amortisation period

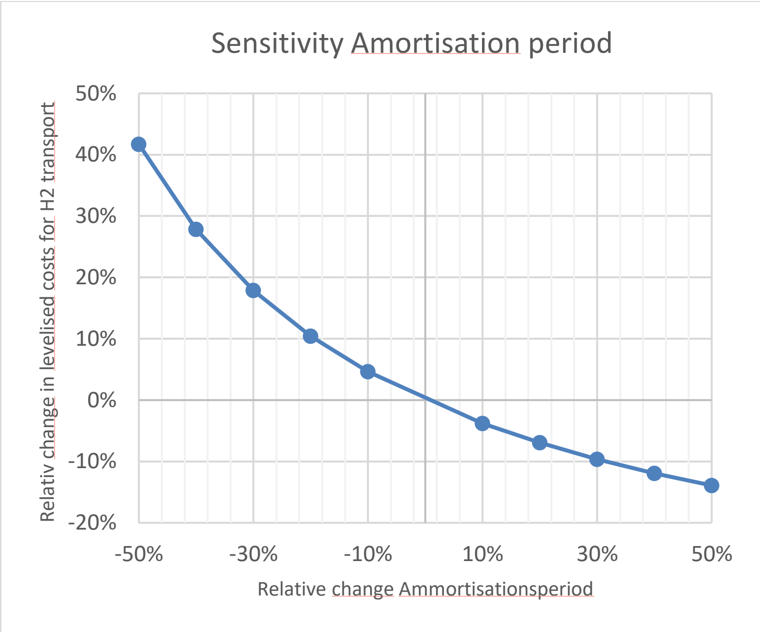

Figure 1: Models sensitivity to changes in the amortisation period

As one can see in Figure 1, the model is very sensitive to the amortisation period. Not so much when it is extended, but especially when it is shortened. This of course leads to the investment costs being proportionally higher when the transport costs are calculated. However, amortization period is often preset by the regulatory bodies and therefore vary a lot not only in value, but also from country to country. By sticking to the base value of 30 years for the pipelines and 15 years for the compressors and city gates respectively, a suitable average is used for the techno economic model as presented in D5.2 and used for D5.3

3.1.2 Interest rates

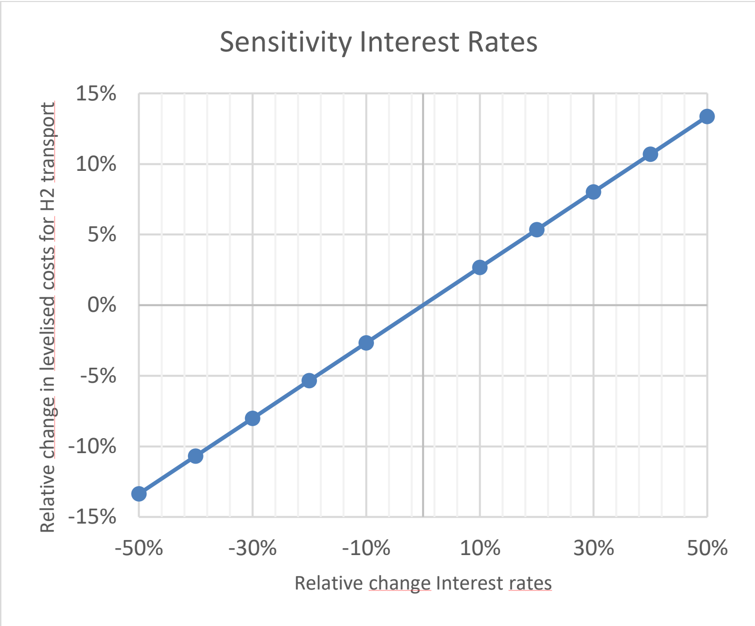

Figure 2: Models sensitivity to changes in the interest rates

Interest rates, on the other hand, have less influence on transport costs and can be extrapolated linearly. Even though interest rate policy is largely determined by national banks, it is also a reaction to the current economic situation. In the current global economic situation, interest rates should therefore be expected to be somewhat higher, leading to a 10-15% increase in transport costs. However, by using the base value of 6% for all the investments one is on the safe side, although some European central banks have increased interest rates significantly in (especially) late 2022 [11]. Interest rates of central banks are likely to be somewhat lower compared to interest rates between banks and institutions implementing infrastructure projects, but at least they represent a trend. A trend as a result of the measures taken against rising inflation and therefore of a temporary nature.

3.1.3 Energy costs

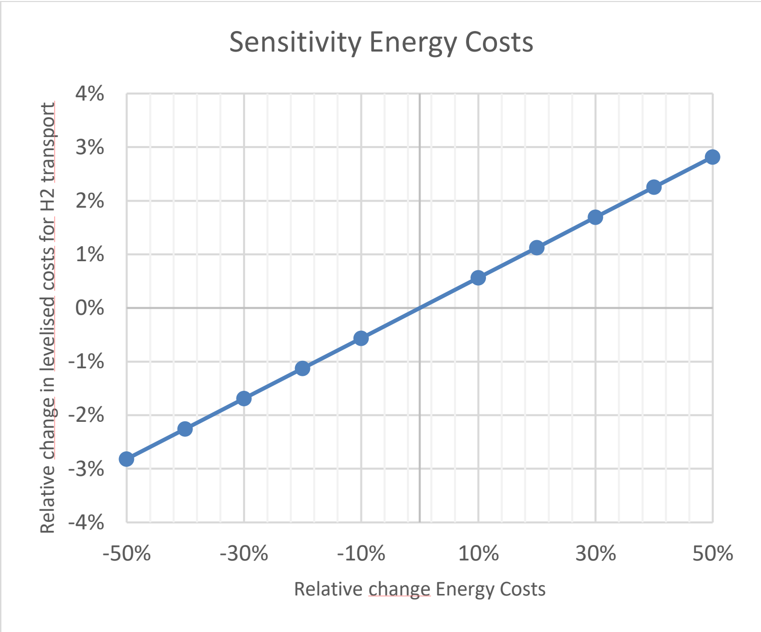

Figure 3: Models sensitivity to changes in energy costs

Interestingly, the model is only very slightly dependent on energy prices. This is mainly due to the fact that the energy, e.g. for compression, is spent on the mixture of methane and hydrogen, but for the transport costs described here, only the share for the hydrogen is calculated. This is an interesting finding of the model, especially now with very volatile energy prices. However, this does not mean that the energy costs for the production of hydrogen do not play a role, on the contrary. Production costs are not considered in this analysis. The energy costs considered here relate only to transport (heating/cooling and compression).

A factor that should not be underestimated is that by the time of compilation of this deliverable (later 2022, early 2023) Europe is confronted with increasing energy prices (for natural gas) for non-household consumers well above 100% on average within the Euro area according to eurostat [6]. Values ranging from 67 % to 271 %. For the presented techno-economic model it would lead to an increase of costs of ca. 4 % to 16 % when interpolating from Figure 3.

3.2 Techno-economic membrane modelling

This section reports the two activities considered in WP5 of HIGGS related to membrane technology:

- Modelling of Pd-based membrane technology
- Cost analysis of the Pd based membranes used in the prototype developed within HIGGS both at lab-scale and at large scale.
- Cost analysis of hydrogen separated for a unit of 1Nm^3/h of hydrogen.

3.2.1 Modelling of Pd-based membranes

The modelling of Pd-based membranes has been carried out with a proprietary modelling tool of TECNALIA.

For fine tuning the model, experimental results of the prototype tested at FHA has been considered (double-skinned (DS) Pd-based, reported as membrane #2 in deliverable D4.2). The gas separation prototype consists in three parts: 1) the feed section, where the blend prepared in the admixture system of the R&D platform is delivered at high pressure to the membrane module, 2) the membrane reactor, where the membranes are allocated and the operating temperature of 400°C is achieved with an oven and 3) an analysis section to check the composition and quantity of the separated flows.

The prototype consists in a feeding line as inlet and two outlets (permeate and retentate). The permeate is the stream rich in hydrogen, and the retentate, rich in methane. A back-pressure regulator is placed at the outlet of the retentate side to set the required trans-membrane pressure difference. The retentate and the permeate lines are connected to the analysis section. It contains mass flow meters to measure and monitor the permeate and retentate flows, which can be analyzed with a gas analyzer.

During the experimental campaign with this membrane at FHA, the feed flow and pressure were modified between 1.12-6.15 Nl·min^{-1} and 10, 20, 40, 60, 80 barg for the mixed gas tests, respectively, maintaining the operating temperature always at 400 °C and the feed H_2 content of 20% (the rest is CH_4).

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For performing the simulations with this model, the following conditions have been considered, as defined by OST:

- Feed H_2 content (the rest is CH_4): 10%, 20%, 30%
- Total feed pressure: 36, 41, 46, 51, 56, 61, 66, 71, 76, 81 bar(abs)
- Total permeate pressure: atmospheric (1 bar-abs)
- Membrane area: 94.79 cm^2 (corresponds to 1 membrane of 21.1 cm long and 14.3 mm outer diameter)
- Target: the H_2 content in the retentate <2% (or the content related to the highest H_2 recovery possible)

Table 3 shows the modelling results for the resulting 30 cases considering the conditions defined above.

Table 3: Modelling results obtained for the double-skinned Pd-based membranes

Case	Feed flow (Nm^3/h)	H_2% con-tent in feed	Pfeed (bara)	Perme-ate flow (Nm^3/h)	H_2 purity permeate (%)	HRF (%)*	Retentate flow (Nm^3/h)	H_2% content in Retentate
1	0.3	20	81	0.05586	99.4703%	92.61%	0.244	1.82%
2	0.27	20	76	0.05049	99.4480%	92.99%	0.22	1.72%
3	0.26	20	71	0.04835	99.4621%	92.47%	0.212	1.85%
4	0.245	20	66	0.04526	99.4671%	92.08%	0.2	1.94%
5	0.232	20	61	0.04269	99.4770%	91.52%	0.189	2.08%
6	0.23	20	56	0.04172	99.5108%	90.25%	0.188	2.38%
7	0.228	20	51	0.0406	99.5445%	88.62%	0.187	2.77%
8	0.227	20	46	0.03941	99.5793%	86.44%	0.188	3.28%
9	0.225	20	41	0.03782	99.6118%	83.71%	0.187	3.92%
10	0.2	20	36	0.03323	99.6122%	82.74%	0.167	4.14%
11	0.27	10	81	0.02347	98.6847%	85.80%	0.247	1.56%
12	0.25	10	76	0.02165	98.6612%	85.43%	0.228	1.60%
13	0.23	10	71	0.01981	98.6326%	84.94%	0.21	1.65%
14	0.21	10	66	0.01796	98.5976%	84.31%	0.192	1.72%
15	0.2	10	61	0.01684	98.6193%	83.03%	0.183	1.85%
16	0.18	10	56	0.01498	98.5751%	82.03%	0.165	1.96%
17	0.17	10	51	0.01384	98.5974%	80.25%	0.156	2.15%

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18	0.16	10	46	0.01267	98.6205%	78.07%	0.147	2.38%
19	0.15	10	41	0.01145	98.6437%	75.32%	0.139	2.67%
20	0.18	10	36	0.01239	98.9091%	68.08%	0.168	3.43%
21	0.33	30	81	0.09483	99.7024%	95.50%	0.235	1.89%
22	0.31	30	76	0.08908	99.7021%	95.50%	0.221	1.89%
23	0.3	30	71	0.08584	99.7118%	95.11%	0.214	2.06%
24	0.29	30	66	0.08257	99.7220%	94.64%	0.207	2.25%
25	0.27	30	61	0.07677	99.7233%	94.51%	0.193	2.30%
26	0.26	30	56	0.07341	99.7352%	93.87%	0.187	2.56%
27	0.25	30	51	0.06998	99.7480%	93.07%	0.18	2.89%
28	0.23	30	46	0.06408	99.7517%	92.65%	0.166	3.06%
29	0.22	30	41	0.06048	99.7668%	91.42%	0.16	3.55%
30	0.22	30	36	0.05877	99.7920%	88.86%	0.161	4.56%

* HRF: Hydrogen recovery factor = hydrogen permeate / hydrogen feed *100

As it can be seen in the results, H_2 content in the retentate lower than 2% can be obtained when operating at high feed pressures, but when lowering the feed pressure, it is more difficult to reach this target even if we go to the maximum hydrogen recovery rate for each of the cases. Anyway, for all the cases that have been simulated, the H_2 content is always lower than 5%. On the other hand, the H_2 purity in the permeate obtained in the simulations is between 98.5 and 99.8 %.

3.2.2 Cost Analysis of Pd-based membranes production

The production cost analysis was carried out for small-scale and large-scale membrane manufacturing of thin (≈ 5 μm) Double Skin Pd-Ag membranes. The DS PdAg membranes were developed by electroless plating onto 14/7 mm outer/inner diameter finger-like 50 cm long porous ceramic supports.

The concepts considered in the cost analysis are: supports (including the sealing connection), the selective layer materials and the production cost (including personnel, electricity consumption, equipment cost and maintenance cost, waste management, quality control of the process/membranes).

3.2.2.1 Small-scale DS PdAg membrane production

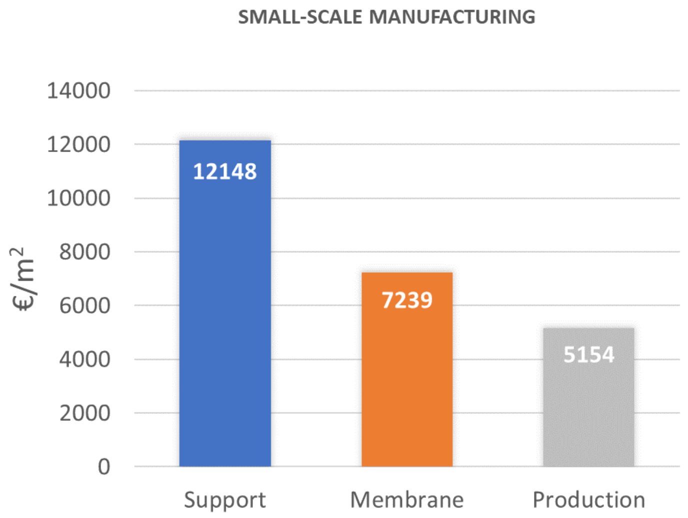
The small-scale (640 membranes/year) production costs have been defined considering the process followed in HIGGS to produce the DS Pd-based membranes at lab scale.

- The main assumptions considered for the small-scale production cost analysis are the following:
    - Porous finger-like ceramic supports:
- Price per 50 cm long, 14/7 mm OD/ID porous supports: 215 €/unit (~10'000 per m^2)
    - DS PdAg membrane deposition onto the support
    - Electroless plating (ELP) of 8 membranes per batch can be produced
    - Chemicals: Raw material production cost (Internal information)
    - 45 cm long effective membrane after sealing
    - Thickness of the thin Pd-Ag membrane: 5 µm
    - Sealing connection: Swagelok connector with graphite ferrule
    - Personnel cost
    - Electricity cost
    - Equipment cost depreciation
    - Quality control of the process/membranes
    - Waste management cost
    - Rejection considered in the calculation
- Number of membranes manufactured per year: 640

The results of the production cost analysis for the lab-scale production of the DS PdAg membranes with the HIGGS project procedure are presented in and Table 4 and Figure 4 hereafter. Values are presented under three main concepts: support (including the sealing costs), selective layer raw materials and production (including personnel cost, electricity cost, equipment cost depreciation, quality control of the process/membranes, waste management cost). Rejection is considered in the calculation.

Table 4: Small-scale DS PdAg membranes production costs when following the HIGGS production procedure. Thin (5 µm thick) selective layer onto 14/7 mm OD/ID. finger-like ceramic supports.

	Small scale	
	€/m²	%
Support (including connections)	12’148	49.5
Selective membrane layer	7’239	29.5
Production	5’154	21.0
TOTAL	**24’541**	**100.0**



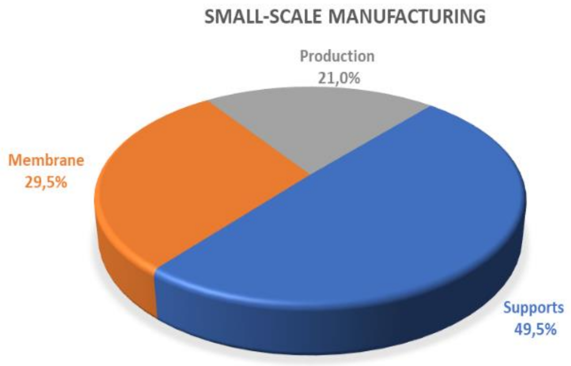


Figure 4: Small-scale DS PdAg membranes production costs breakdown when following the HIGGS production procedure (left: €/m2 per each concept and right: % of each concept with respect to the total cost).

Main conclusion of this analysis shows that:

- The total cost for producing DS PdAg membranes following the HIGGS procedure is 24’541 €/m². The highest cost is related to support including the sealing (49.5% of the total cost) being the membrane raw material cost the second highest (29.5% of the total cost). Finally, production cost is 21.0% of the DS PdAg membranes cost.

We should point out that the total cost shown in the previous figures describes the cost for producing 1 m² membrane area.

3.2.2.2 Large-scale DS PdAg membrane production

For the large-scale production, it has been considered a price for each support of 80 €, provided that ceramic membranes for water filtration that are the basis of ceramic supports used in this application can be obtained at a cost of 20 €/support at large scale.

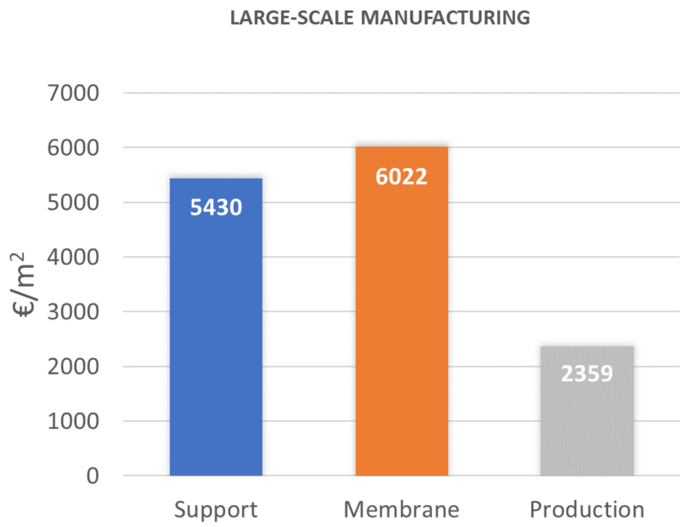
In addition, it has been considered that at large scale up to 11’200 membranes per year can be manufactured. A cost scale-up factor of 7 has been considered regarding the equipment to be able to produce the 11’200 membranes per year.

In this new process, 32 membranes can be produced simultaneously.

The results of the production cost analysis for the large-scale production of the DS PdAg membranes are presented in Table 5 and Figure 5 hereafter. Values are presented under three main concepts: support (including the sealing costs), selective layer raw materials and production (including personnel cost, electricity cost, equipment cost depreciation, quality control of the process/membranes, waste management cost). Rejection is considered in the calculation.

Table 5: Small-scale DS PdAg membranes production costs when following the HIGGS production procedure and the optimized production procedure. Thin (5 µm thick) selective layer onto 14/7 mm OD/ID finger-like ceramic supports.

	Large scale	
	€/m^2	%
Support (including connections)	5’430	39.3
Selective membrane layer	6’022	43.6
Production	2’359	17.1
TOTAL	**13’812**	**100.0**



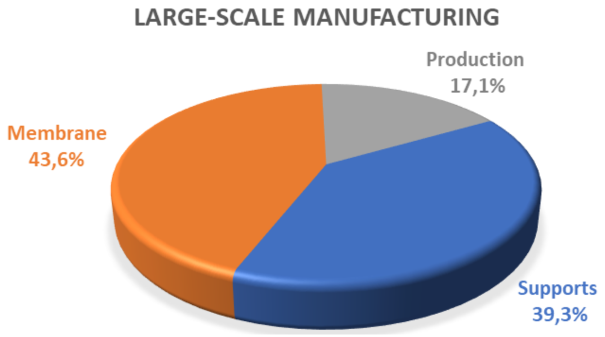


Figure 5: Large-scale DS PdAg membranes production costs breakdown when following the HIGGS production procedure (left: €/m2 per each concept and right: % of each concept with respect to the total cost).

Main conclusion of this analysis shows that at large scale, the total cost is decreased to 13’812 €/m^2. This is approximately 37% of the cost when compared to lab scale production. The highest cost now is related to membrane raw material cost (43.6% of the total cost) being the support (including sealing) cost the second highest cost (39.3% of the total cost). Finally, production cost is 17.1% of the DS PdAg membranes.

3.2.3 Cost analysis of hydrogen production

In terms of Operation expenditure (OPEX) of hydrogen separation system, since the stream is already fed at high pressure, there is no need for compression or vacuum to increase the partial pressure difference and hence, just the cost of heating the membranes and stream should be considered.

Below, a calculation of the cost for 1 Nm^3/h of hydrogen is shown. For this example, the following assumptions have been considered:

- Electricity cost: 0.13 €/kWh[2] (Date: 15/11/2022. Price for Spain. Source: https://euenergy.live/country.php?a2=ES)
- Energy consumption by the ovens for preheating of the stream and for the membrane module: 0.41 kWh/Nm$^3_{H2}$
- The hydrogen produced during the testing campaign considered for this calculation was 0.05586 Nm^3/h
- Cost of electricity per hour of operation:

$$0.41\frac{kWh}{Nm3_{H2}} \times 0.13\frac{€}{kWh} \times \frac{1Nm3/h}{0.05586Nm3/h} = 0.95€/Nm3_{H2}$$

Finally, if we consider that the lifetime of the membranes is 5 years, and that hydrogen can be produced 24/7, then we can conclude:

- Total Hydrogen produced: 5 years x 365 days x 24 hours x 1Nm^{3}h = 43’800Nm^3 of H_2. Where:
  - System depreciation: 2’343.8 €* / 43’800 Nm3h = 0.054 €/Nm^3 of H_2

[2] Average price for selected countries in Europe derived from https://www.statista.com/statistics/1267500/eu-monthly-wholesale-electricity-price-country/ (last checked on 08.02.2023)

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- OPEX: 0.95 €/Nm^3 of H_2

* Cost of Membrane to produce $1Nm^3/h$:

$$13'812\frac{€}{m^2} \times 94.79 \times 10^{-4} m^2 \times \frac{\frac{1Nm3}{h}}{\frac{0.05586Nm3}{h}} = 2'343.8\ €$$

3.3 Results not considering gas separation technologies

This section considers future scenarios for hydrogen transport in natural gas grids where separation technologies are not involved. Two scenarios have been studied: 1) a predefined mixture of natural gas and hydrogen is injected at the model's inlets and 2) several hydrogen production projects inject hydrogen in the local transport grid.

It is pointed out again that the grid section modelled in this WP is only a means to an end. This means that it is not about modelling the German network and/or investigating the flow of natural gas from the East (or any other specific region). It is about having a representative grid section to compute any results at all. In a subsequent step, these results are to be extrapolated or put into a European context in section 4. The selection of the network section is based, as already described in D5.2, on a.) the availability and b.) the quality of the available data.

3.3.1 Premixed H2/NG blends at model inlets

This investigated case injects a predefined mixture of natural gas and hydrogen at the model's inlets as shown in Figure 6. Based on the mass flows respectively the volume flows from the pure natural gas flows, part of the natural gas is replaced by hydrogen. Blends of 10, 20, 30, 60 and 100 vol.-% of hydrogen are investigated.

A full description of the case is given in section 3.5.1.2 of D5.2 of HIGGS as case 2.1.

Figure 6: Case 2.1: Premixed gases at model inlet nodes

3.3.1.1 Levelised cost for hydrogen transport

A meaningful parameter for the TSOs for billing purposes is the levelised costs with the unit €/MWh/1000km. This value will be used to compare different systems and technologies in the upcoming sections of this deliverable, where results are presented. Figure 8 shows the levelised costs for hydrogen transport in a retrofitted transmission system for 10, 20, 30, 60 and 100 vol.-% hydrogen concentrations.

The results show that, no significant differences in the costs for transport are likely to be expected up to 40 vol.-%, and they are about twice as high as the switch to pure hydrogen networks as Figure 8 shows. The reason for this is mainly the amount of energy that is transported in the mix. With increasing vol-% of hydrogen, the proportion of energy from hydrogen in the mix does not increase linearly, as Figure 7 shows. The annual expenditure can thus be shifted to only a small amount of energy.

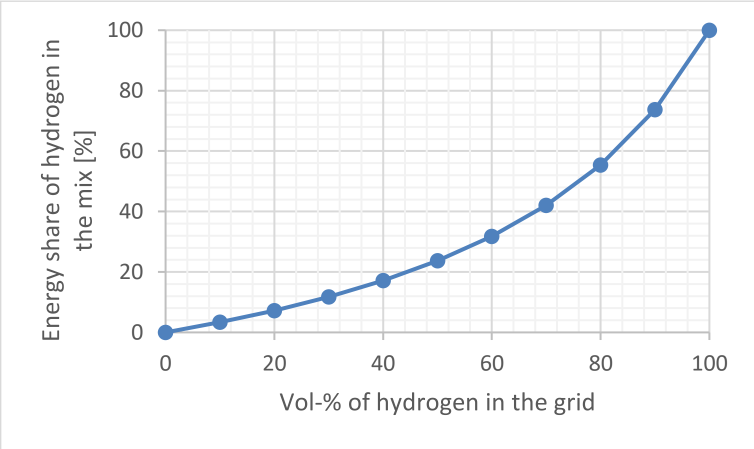


Figure 7 Share of Vol-% of hydrogen in the grid vs. energy share pf hydrogen in the mix

To be fair, it has to be said that further investments such as membranes and methanation systems for aquifer storage (or similar) would have to be made here but were not part of the case definition. Furthermore, it shows that there is basically no difference in the costs for transport between winter and summer. The reason for this being that the retrofit needed is the same for both seasons. What is slightly different though, is the need for pre-heating or cooling. But as shown in the sensitivity analysis in section 3.1.3, this has basically no effect on the cost for transport.

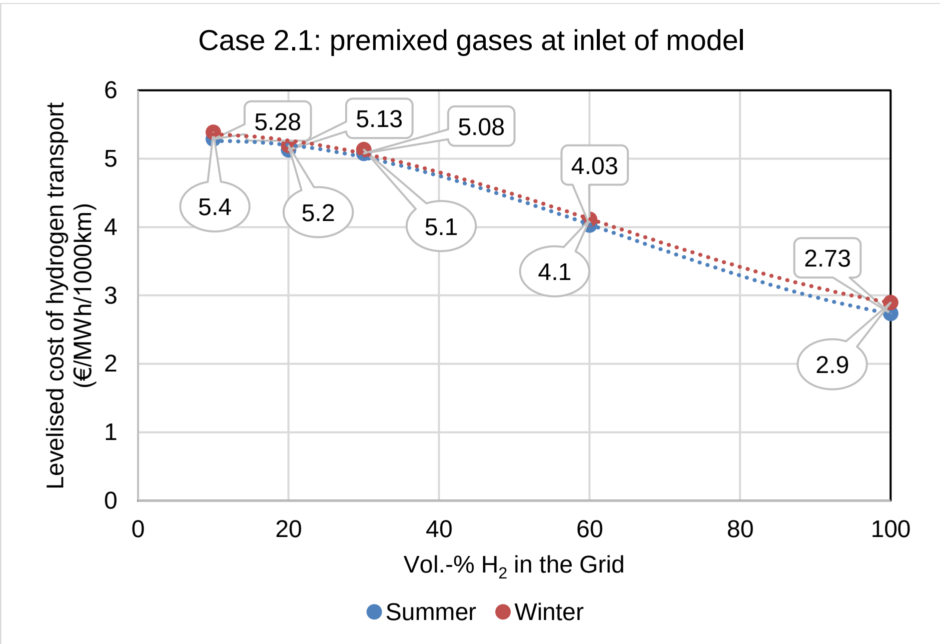


Figure 8: Levelised costs for hydrogen transport via retrofitted pipeline transmission system at different admixture levels

The approx. 3 euros for 100% systems also roughly coincide with the middle scenario of the backbone study shown in Figure 9, where the retrofit was also assumed at 75%. [12] Eventually, the 3 - 6 €/MWh hydrogen seems to be a relatively small premium compared to the production costs of 25 - 50 €/MWh assumed for green hydrogen in the medium and long term.[2]

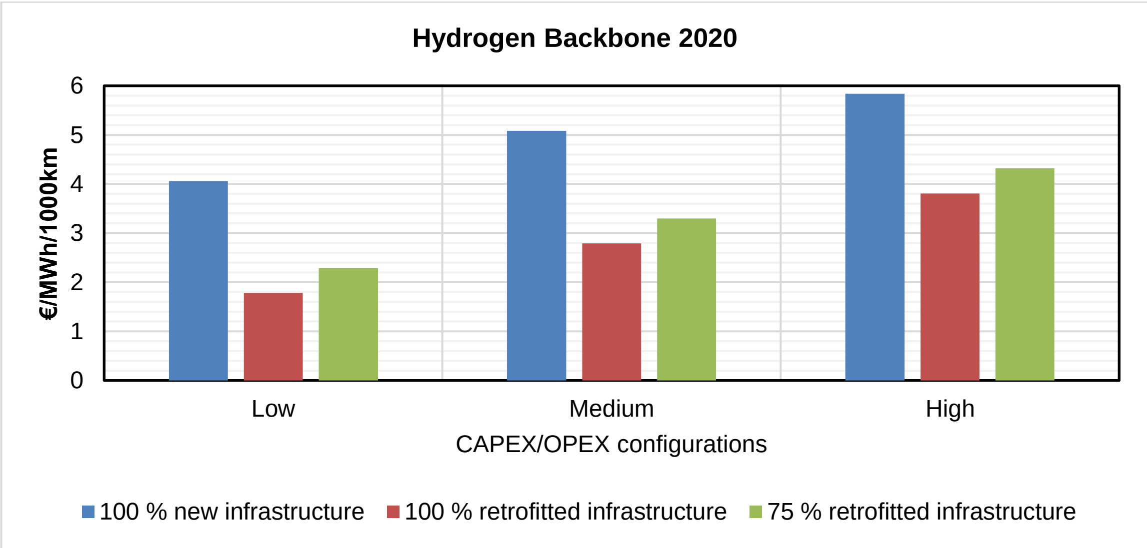


Figure 9: Backbone study results regarding the levelized costs of hydrogen transport [12]

3.3.1.2 Comparison with other modes of hydrogen transport

When talking about other hydrogen transport modes, a) the form and b) the means are meant. Hydrogen can be transported in the form of compressed hydrogen gas (CGH_2), liquefied hydrogen gas (LH_2), liquid organic hydrogen carriers (LOHC) or ammonia (to name the most important). It is transported by pipelines, trucks and ships. Not all forms of hydrogen are suitable for all means of transport. Depending on the distance and volume transported, certain combinations are better suited than others. Figure 10 shows the most common combinations.

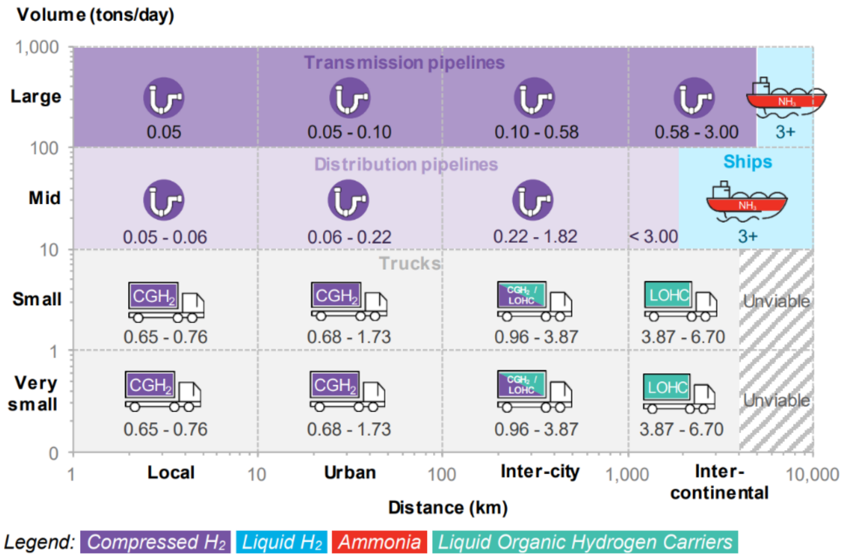


Figure 10: Hydrogen transport costs based on distance and volume in $/kg [2]

Based on the higher heating value (HHV) of hydrogen and starting from the 1000 km line in Figure 10, the prices per kilogram result in the levelised costs for the transport of hydrogen shown in

Table 6.

Table 6: Costs comparison of different forms- and means of hydrogen transport without separation

Form	Mean of transport	€/MWh/1000km[3]	Source
CGH_2	Pipeline	2.7 – 5.8	WP5 HIGGS
CGH_2	Pipeline	2.3 – 4.3	[9]
CGH_2	Pipeline	2.5 – 14.5	[2]
CGH_2	Truck	17 – 43	[2]
LH_2	Ship	> 15	[2]
LH_2/LOHC[4]	Truck	24 – 97	[2]

Here, too, the results of the techno-economic model are of the same order of magnitude as [2], at least as far as transport in pipelines is concerned. However, the transport of hydrogen at high pressure in pipelines is by far the most cost-effective option. The low volumetric energy density speaks against large-scale transport by trucks. Although this is less of an obstacle for LH2, the energy requirement and the necessary infrastructure for liquefaction have a negative impact on transport costs.

[3] Assuming Dollar to Euro parity
[4] *Even though LOHC is cheaper than LH2 for long distance trucking, it is less likely to be used than the more commercially developed LH2* [2].

3.3.2 Locally injected hydrogen

Projects that produce hydrogen through renewable energy (PV + Wind) inject hydrogen directly into the grid. Different sizes of electrolyzers are considered.

		Summer	*Winter*
		09.06.2017	*11.11.2017*
		10:00	*18:00*
Westküste 100:	30 MW_{el}	≙ 2 ksm^3/h[5]	≙ 9 ksm^3/h
Hybridge:	100 MW_{el}	≙ 14 ksm^3/h	≙ 19 ksm^3/h
NorthH2:	3,000 MW_{el}	≙ 99 ksm^3/h	≙ 573 ksm^3/h

The following questions are of particular interest:

1) What are the impacts on the gas composition in the grid?
2) What are the seasonal effects of green H_2 production?

A full description of the case is given in section 3.5.1.3 of D5.2 of HIGGS as case 3. It is an imaginary scenario in which these three projects inject the hydrogen produced instead of using it in their actual tasks.

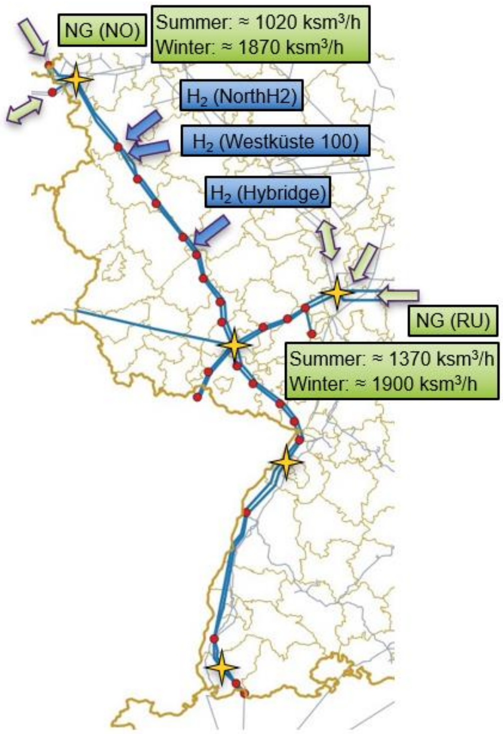


Figure 11: Case 3: Locally injected hydrogen

3.3.2.1 Modelling the injection of hydrogen

In Deliverable 5.2, three projects were identified (West Coast 100[6], North2[7] and HyBridge[8]), which aim to produce and distribute hydrogen in larger quantities in the foreseeable future. Whether this distribution will effectively take place via the gas transmission network and in the envisaged quantity is excluded from this consideration. What is more important is that the feed-in of a considerable

[5] ksm^3/h: kilo standard cubic meters per hour
[6] https://www.westkueste100.de/
[7] www.north2.eu
[8] https://www.hybridge.net/

amount of hydrogen could in principle be possible. The projects differ in size and concept. While Westkueste100 and North2 produce hydrogen from green offshore wind power, HyBridge focuses on sector coupling as a starting point for the purchase of excess electricity.

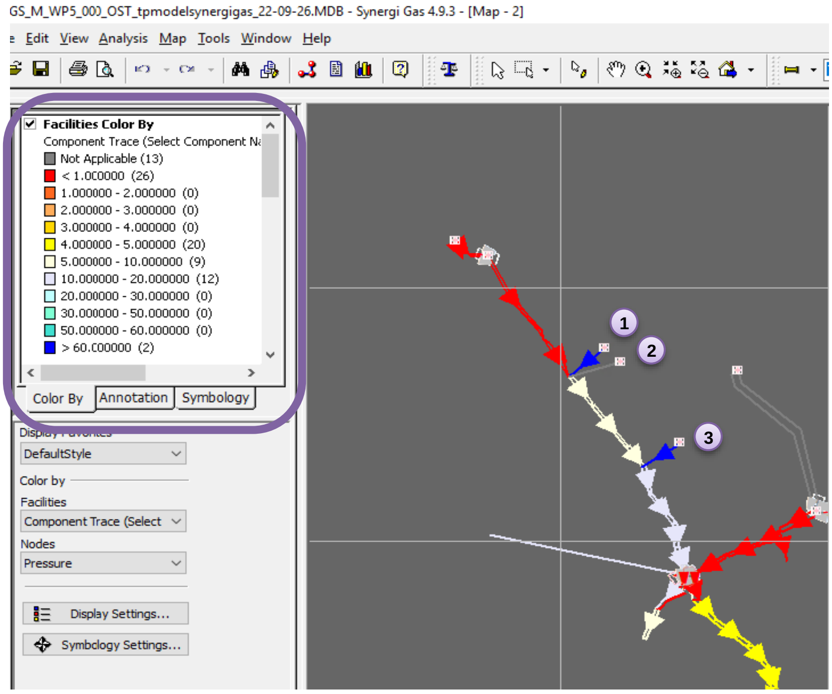
Table 7: Information about the investigated hydrogen production sites used in HIGGS case 3.

Project	Energy Source	Location	P_el_in [MW]	El. -> H2 eff. (%, est.)	Profile dependencies
Westküste100	Offshore Wind	Schleswig-Holstein	50	60%	Offshore windspeeds 2019, height & turbine
North2	Offshore Wind	Netherlands	3'000	65%	
Hybridge	Sector coupling	Lower saxony	100	65%	electricity cost or neg. balancing energy

For the offshore wind profile, a profile from the North Sea region was obtained from renewables.ninja[9]. The portal offers the possibility to simulate the energy yield of wind generators from various manufacturers and at different hub heights. Our offshore wind profile was created with a hub height of 150 m, 3 GW installed generator capacity and the MERRA-2 data set from 2019. The profile has been used equally for the West Coast100 and the North2, both of which intend to produce hydro fuel from North Sea offshore wind turbines.

For the relative production profile of the HyBridge electrolyser, the chosen approach was that the plant produces hydrogen when either a) the purchase price of electricity is very low or b) negative control energy is available in sufficient quantities. In the case of cheaply available electricity, the wholesale prices of 2017 were used and a threshold value of 25 €/MWh was applied. If the electricity price is lower, hydrogen is produced. This was the case for 1,620 hours. Information on negative control energy was obtained from reBAP[10]. Whenever this was negative, the corresponding amount was provided by the electrolysis up to the maximum possible purchase capacity of 100 MW_{el}. This was the case for a total of 3488 hours with an average reference power of 86.4 MW_{el}. By combining the two conditions for electrolysis operation, the total operating time for 2017 resulted in 4,301 operating hours with an average of 90.7 MW_{el} or 44.5 MW_{el} for year-round operation.

[9] https://www.renewables.ninja/
[10] https://www.regelleistung.net/ext/static/rebap?lang=en



Location of H2-Injection on the HIGGS-Modell:

(1) NorthH2

(2) Westküste100

(3) HyBridge

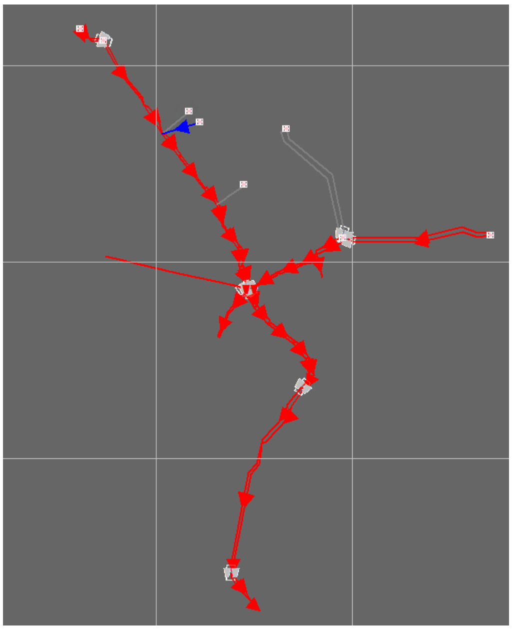
If the hydrogen-carrying gas line is blue, the H2 node is active; if it is grey, it is correspondingly inactive. The H2 content by Vol-% in the gas mixture is indicated by colour.

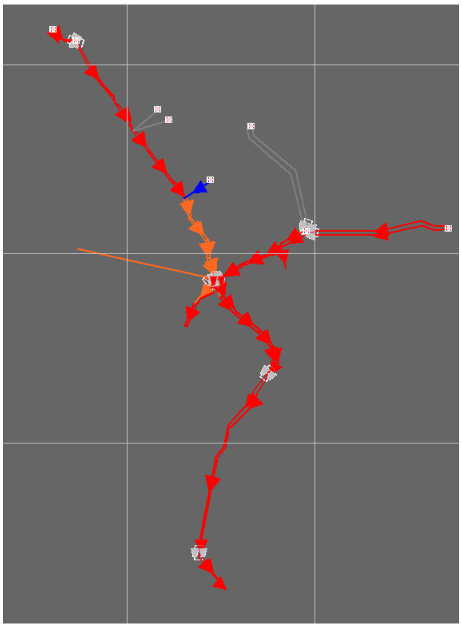
Figure 12: Allocation of the H2-Injection projects in HIGGS Modell

NorthH2 and Westküste100 are connected to the same connection point in the transmission grid. This is because both projects follow the same production profile, but the NorthH2 project has a significantly higher production capacity. Therefore, it was decided not to have both projects connected and feeding hydrogen at the same time, as this would not make a significant difference compared to NorthH2 alone.

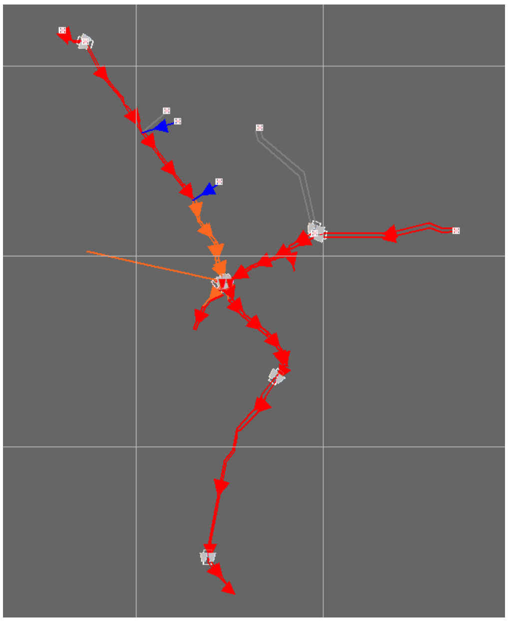
3.3.2.2 Impacts on the gas composition in the grid

Let's start by looking at what kind of impact the two smaller projects, namely Westküste 100 and Hybridge or the combination of both, would have on the gas composition in the modelled grid. Figure 13 shows where hydrogen is injected into the grid, which is where the arrows are shown in blue and consequently the concentration is 100%. However, the amount of hydrogen is so small that it does not exceed 3 % by volume in the entire grid under investigation. Under these conditions, transport beyond the national borders to France or Switzerland would therefore even be conceivable without restrictions according to deliverable 5.1 of HIGGS. With the current legal situation, it would even be feasible today. It can be therefore concluded that no separation technology would be needed in such a case. At least not on a transmission level. The 3% threshold is compatible with most cases, but there can be still final users that demand a higher NG quality (e.g. chemical industry using NG as feedstock). In section 4it will be discussed what these results mean in a pan-European context.





Westküste (30 MW_{el}) Hybridge (100 MW_{el})



Westküste + Hybridge (130 MW_{el})

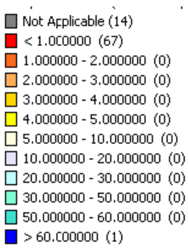


Figure 13: Hydrogen concentration along modelled grid section with relative low amounts of hydrogen injected during summer

The situation looks somewhat more exciting if hydrogen from NorthH2, as shown in Figure 14, is fed into the modelled. In terms of electrical power, more than 20 times the electrical power than the examples on Figure 13 is fed into the grid. Consequently, the concentration of hydrogen rises locally to over 10% by volume. The concentration of hydrogen in the grid not only rises to the injected hydrogen, but also due to less flow of methane downstream. Accordingly, two processes have to be considered for the determination of the hydrogen concentration along a pipeline: Firstly, the amount of hydrogen injected and secondly, the consumption of natural gas along (which tends to become less and less the further downstream a city gate is from an inlet or intersection).

This can lead to a level of hydrogen where the question of transport across national borders becomes more difficult to solve. Without a uniform Europe-wide solution for the permitted hydrogen concentration in the transmission network, the use of membranes is unavoidable in this case. Transport costs would therefore further increase. However, demand would also have to be available to absorb the hydrogen that cannot or is not allowed to be transported across borders. If this is not the case, transport could become financially unattractive. More on the cost of transport when membranes are included can be found in starting from section 3.4

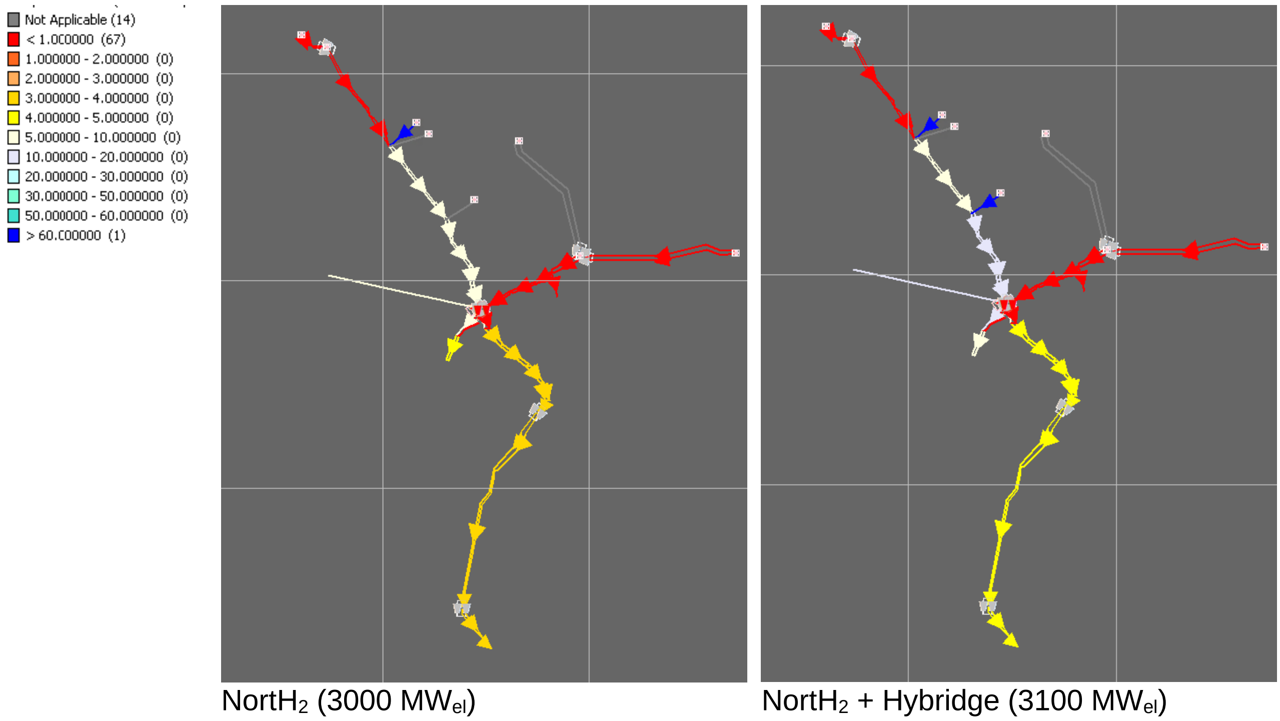
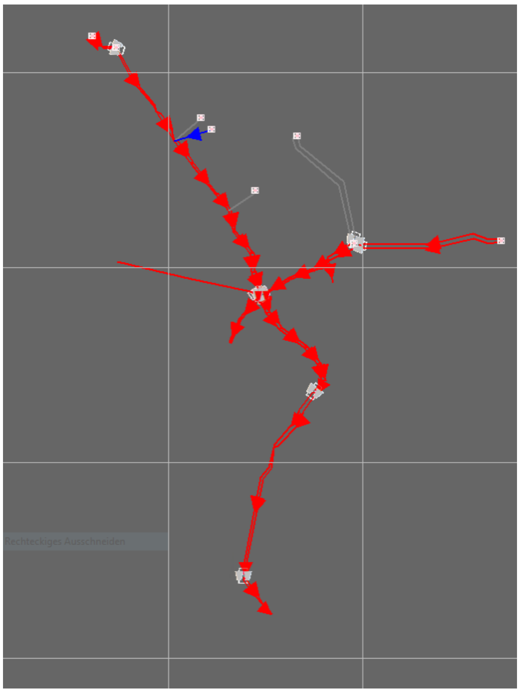
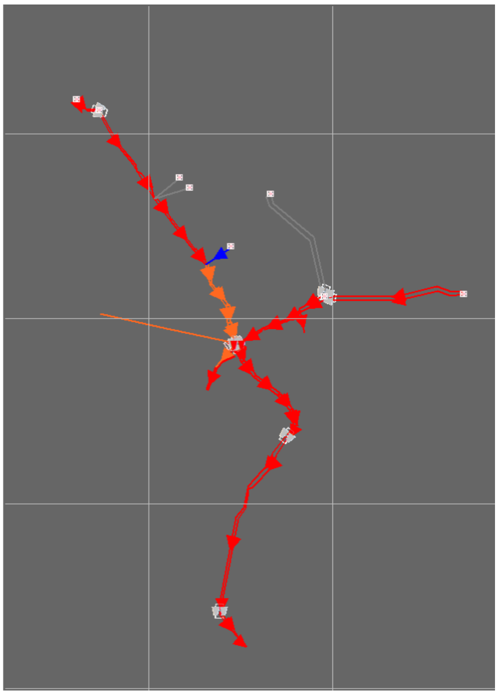


Figure 14: Hydrogen concentration along modelled grid section with relative high amounts of hydrogen injected during summer

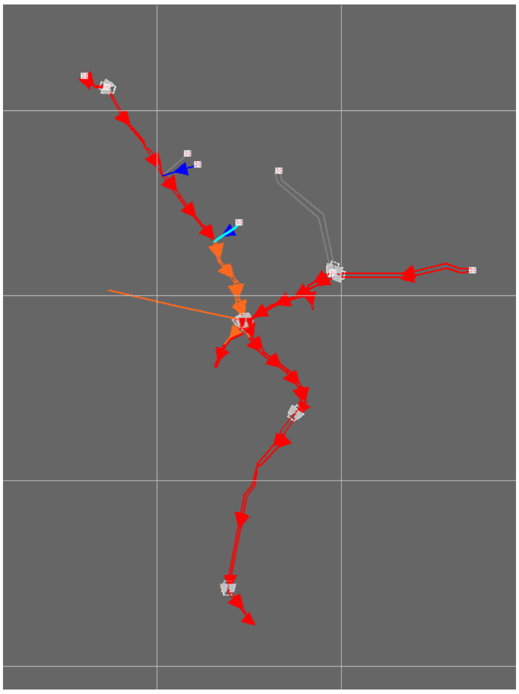
To determine whether there are seasonal effects on the hydrogen concentration, the same calculations were also carried out for a typical winter day. As expected, and as shown in Figure 15, there are no high hydrogen concentrations in the modelled grid during winter either. Concentration still being about max. 1-3 % by volume of hydrogen in the grid. Hence, the same conclusions can be drawn here as in the summer cases.



Westküste (30 MW$_{el}$)



Hybridge (100 MW$_{el}$)



Westküste + Hybridge (130 MW$_{el}$)

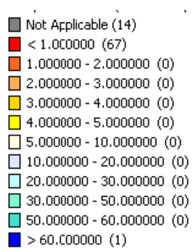


Figure 15: Hydrogen concentration along modelled grid section with relative low amounts of hydrogen injected during winter

As previously seen for the summer case, hydrogen injection on the scale of NorthH2 looks very different in terms of hydrogen concentration (see Figure 16). Compared to the summer, where only locally concentrations of over 10 vol% occur after Hybridge, we have over 10 vol% of hydrogen over long stretches of the modelled network in winter. Since the amount of hydrogen fed into the grid is higher in winter then in summer, one would have to conclude that either the same amount of natural gas is transported in winter and summer or that less natural gas flows through the transport pipelines in winter. That sounds somehow counterintuitive at first.

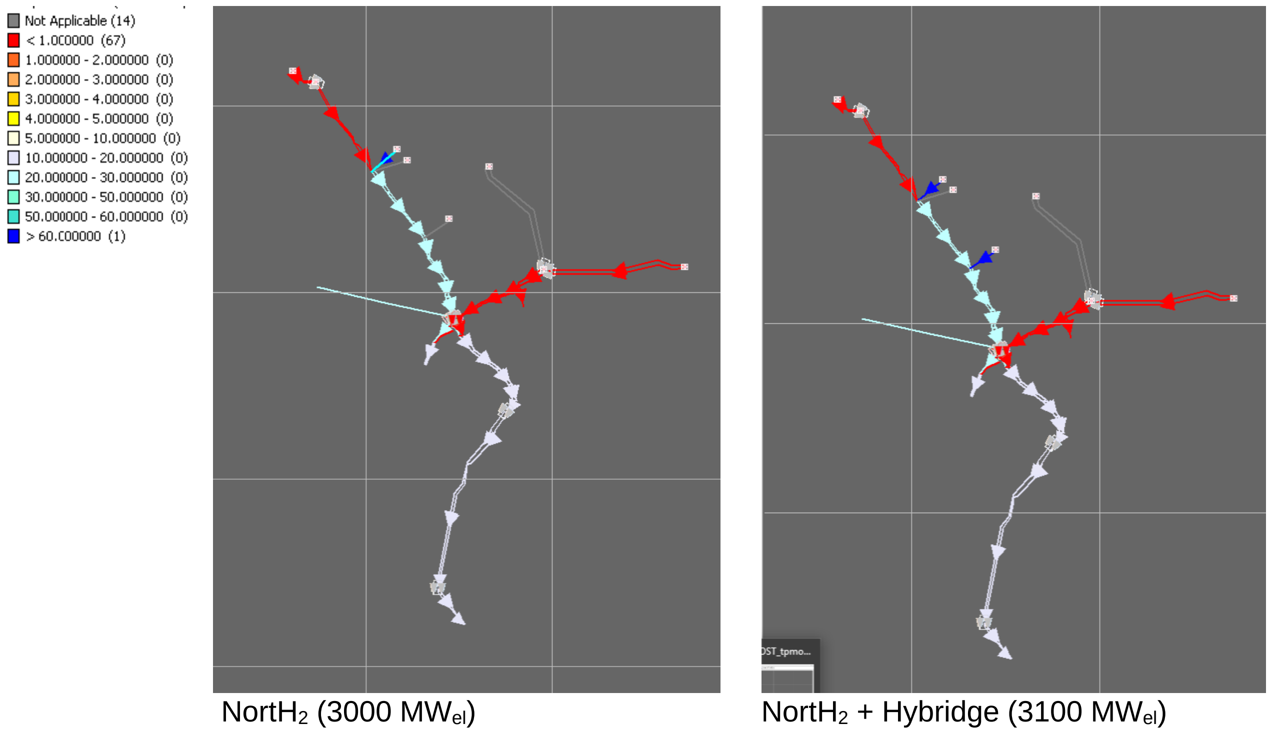


Figure 16: Hydrogen concentration along modelled grid section with relative high amounts of hydrogen injected during winter

However, the 2017 data for this section shown on Figure 17 of the network shows just that at the inlet. One thing to keep in mind however is that this curve does not necessarily indicate demand or consumption because it only shows the flow on a transmission level. The demand for natural gas is indeed in winter than in summer. One option, however, is that this demand is served to a large extent by the full storage facilities on the distribution level. These were filled in the summer via the transmission level. Therefore, less natural gas is needs to be transported on the transmission level. The second option is that in this section fewer natural gas arrives at the inlet due to higher demand higher up in the (not modelled) grid. Higher demand on distribution level still would need to be served from full storages.

What's also worth mentioning is that ultimately the concentration of hydrogen in the grid is not only a question of supply, but also of demand. The presented results and the simulations are based on data from the past (2017) and only allow a limited prediction of future energy demand. What will be purchased in what quantity at the city gates will strongly influence the concentration of hydrogen in the grid. This will certainly have to be considered in the potential expansion of the network with separation technology like membranes.

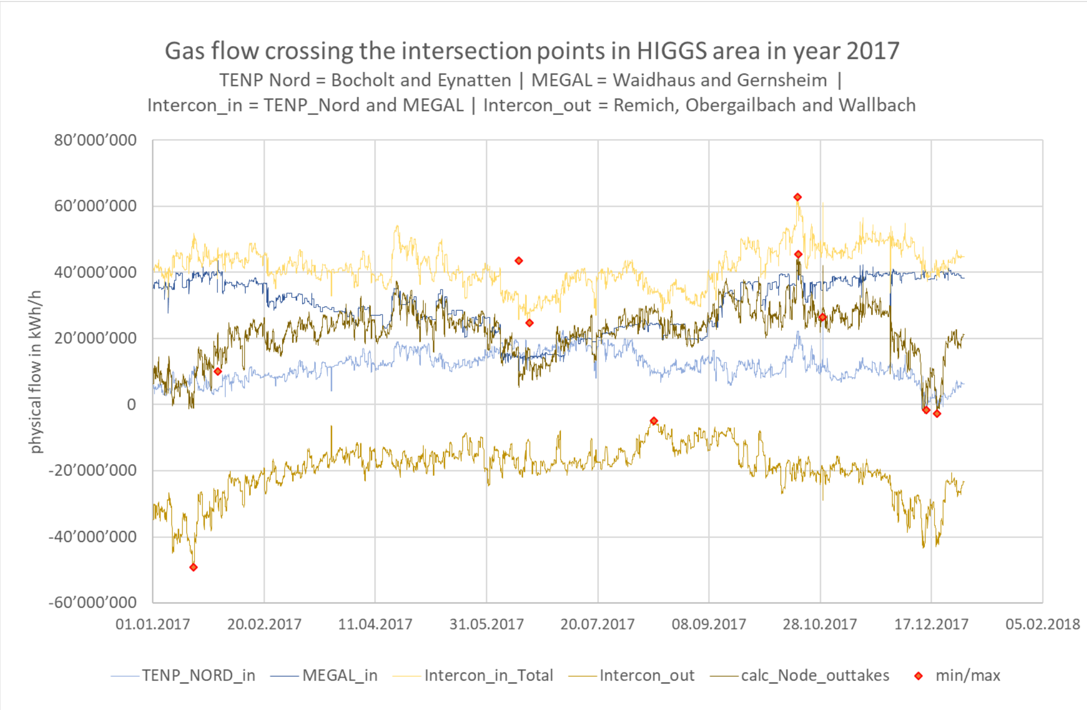


Figure 17: gas flow via the interconnection points in 2017 for the modelled section [4]

3.4 Results including gas separation technologies

In the cases where separation technology is now used, the same thermal flows and inputs are used as without separation technology. Consequently, different amounts of hydrogen are transported in absolute quantities in the individual subcases for summer and winter according to the vol-% of hydrogen. The same applies to the transport of methane according to Figure 17. Again, all these considerations based on a retrofitted grid.

Depending on the subcase the target product, the product that is kept or reinjected into the grid can either be hydrogen or natural gas. In the case of hydrogen, the product is recompressed from ambient pressure to current line pressure. In the case of natural gas respectively methane, there is no need for recompression, nor reinjection. The methane stays at current line pressure.

3.4.1 Moderate, selective use of hydrogen

Based on case 2.1 described in section 3.3.1 it is now assumed, that hydrogen injected at the inlet points of the grid is only going to be used in a moderate way and therefore all the nodes need to be equipped with membranes. The target product (hydrogen) from separation is then reinjected into the grid.

This case is going to investigate the effects of injecting 10, 20 and 30 H_2 vol.-% at the inlets. Allowed concentration of hydrogen in the permeate is 2 and 10 Vol-%

A full description of the case is given in D5.2 of HIGGS as case 2.2 (section 3.5.2.1)

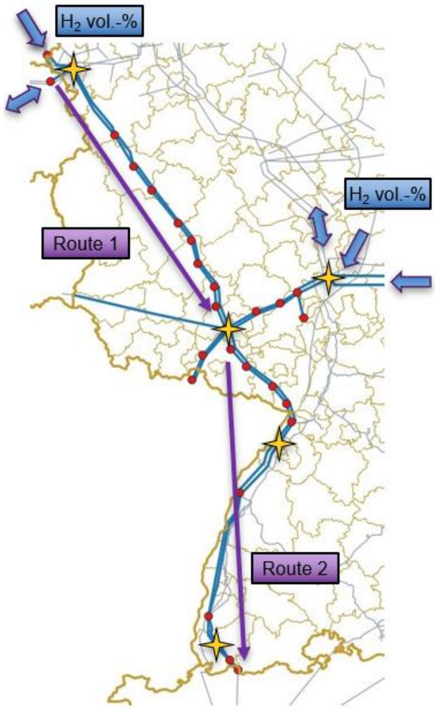


Figure 18: Case 2.2: Moderate use of hydrogen

3.4.1.1 Levelized cost for hydrogen transport

In order to put the transport costs for this case into context, it is recalled that in section 3.3.1 the transport costs without membranes were determined. These amount to slightly more than 5 €/MWh/1000km for 10-30 vol% hydrogen at the inputs for a converted natural gas network. In comparison, the transport costs according to Figure 17, considering membranes and permitted hydrogen in the permeate, amount to 10.7-21.1 €/MWh/1000km in summer. In winter, however, the costs rise again from 18.1-47.3 €/MWh/1000km. Consequently, the transport costs are *2-9.5 times more expensive* when the membranes are included.

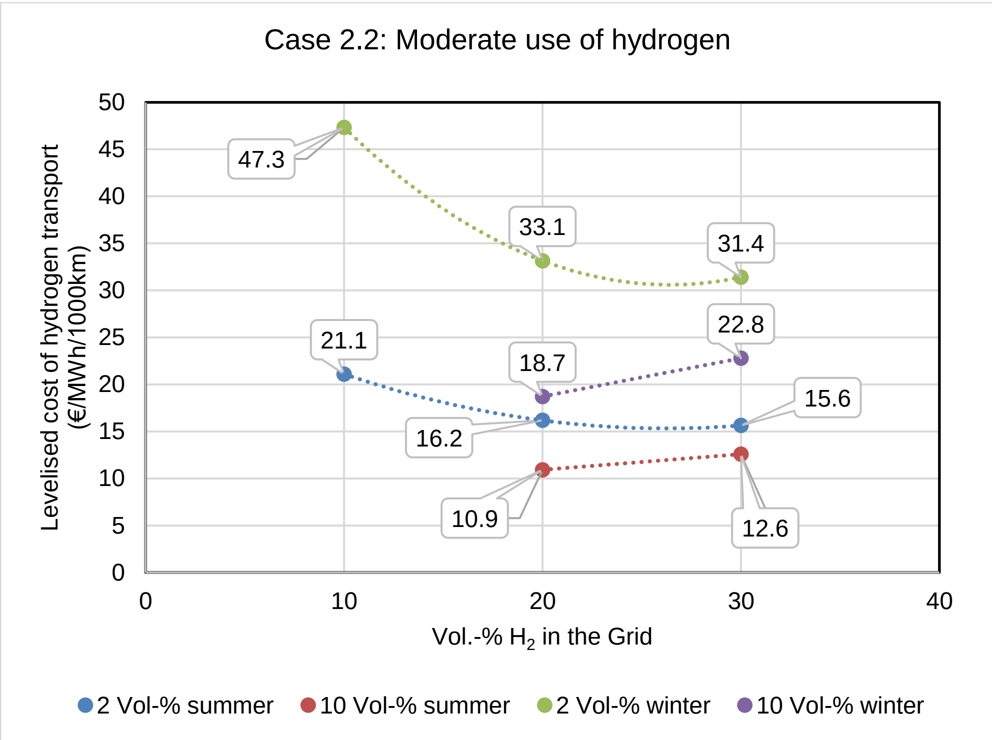
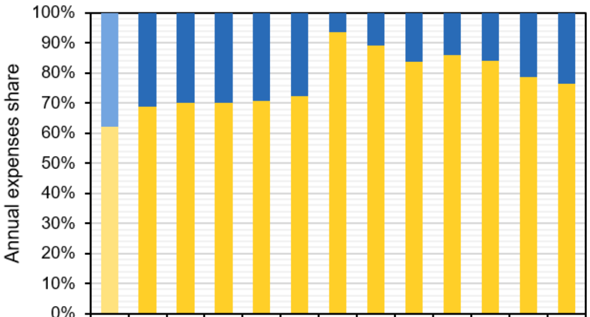


Figure 19 Levelised costs of hydrogen transport when considering separation technology at all the nodes of the TENP section. Different levels of hydrogen allowed in the permeate respectively distribution level.

The first thing that stands out is the clear seasonal differences. These can be directly attributed to the amount of hydrogen that has to be transported. This in turn has various mechanisms that primarily drive CAPEX (€/year), as Figure 20 shows.

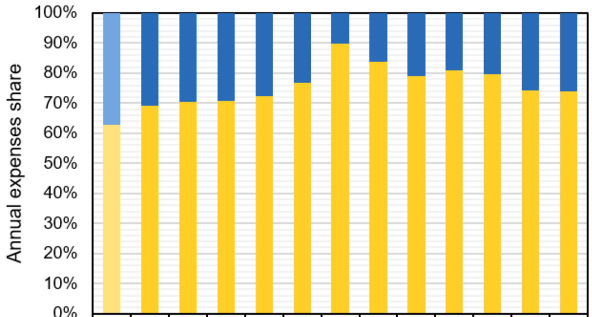
First, the absolute amount of hydrogen is higher in winter. This means that more hydrogen must be separated in winter for a given target concentration in the permeate. This in turn means that the required membrane area is larger. Hence, the investment costs increase. Secondly, the required membrane area is also influenced by the separation efficiency: the lower the concentration of hydrogen in the feed gas, the less feed gas flow is required to achieve the separation efficiency. This means, however, that less hydrogen can be separated per time per area. Calculated over a year, this means that the investment costs must be distributed over less hydrogen, which in turn negatively affects or increases CAPEX. Finally, the CAPEX is also driven up by the short lifetime of the membranes of only 5 years, as described in section 3.2.2.

The OPEX, proportionally responsible for 6-18% of the annual expenditure, also have a not insignificant share in the transport costs. The variable OPEX are directly proportional to the amount of hydrogen separated. The costs are drawn by the energy demand for the separation itself on the one hand and the reinjection[11] of hydrogen into the grid on the other. The following applies to both steps: the more hydrogen, the more expensive and the higher the share of annual costs. The variable OPEX can be reduced primarily by increasing the permitted proportion of hydrogen in the permeate (and thus at the distribution level), as Figure 19, among other things.



	100 (as-is)	211	212	213	214	215	221	222	223	224	225	231	232
OPEX	173	18.	37.	60.	126	264	33.	82.	183	60.	132	53.	49.
CAPEX	284.	41.2	87.3	140.	308.	697.	491.	682.	959.	373.	704.	197.	160.

computed use-cases (winter)



	100 (as-is)	211	212	213	214	215	221	222	223	224	225	231	232
OPEX	167	18.	36.	58.	118	211	23.	62.	128	50.	99.	43.	42.
CAPEX	284.	40.6	86.8	140.	307.	697.	210.	325.	482.	211.	392.	127.	119.

computed use-cases (summer)

Figure 20 share of CAPEX and OPEX in annual expenses across all simulated cases for both summer and winter. 211-215 (premixed gases) without membranes. 221-225 (moderate use H_2) and 231-232 (technology diversification) with membranes

Whether reinjection into the transport network is the best solution is still open from an operational point of view and not the subject of this study. Intermediate storage and further transport by mean

[11] Modelled as isothermal one-stage compression from ambient pressure (permeate pressure) to current line pressure of 65 bar (average). Although technically very difficult to implement (if at all), the energy required is only 0.4 % less for the multi-stage compressor compared to a three-stage compressor with a compression ratio of 4. To reduce the complexity of the evaluation, a single-stage compressor was therefore assumed.

other than pipelines would also be conceivable. There will hardly be any advantages in terms of operating costs, as intermediate storage also requires separation and compression.

3.4.1.2 Gas composition in the grid

If the hydrogen is injected back into the natural gas grid, there may be a local concentration of hydrogen in the grid. Depending on the natural gas consumption at the individual city gates, this can be more or less pronounced. Furthermore, the permissible share of hydrogen in the permeate also plays an important role. The higher the percentage, the less critical the local accumulation or the smaller the vol-% of hydrogen at a certain point. This is important because the existing network does not have to be modified for the (maximum) vol-% of hydrogen at the inlets, but according to the expected higher concentrations of hydrogen due to accumulation downstream.

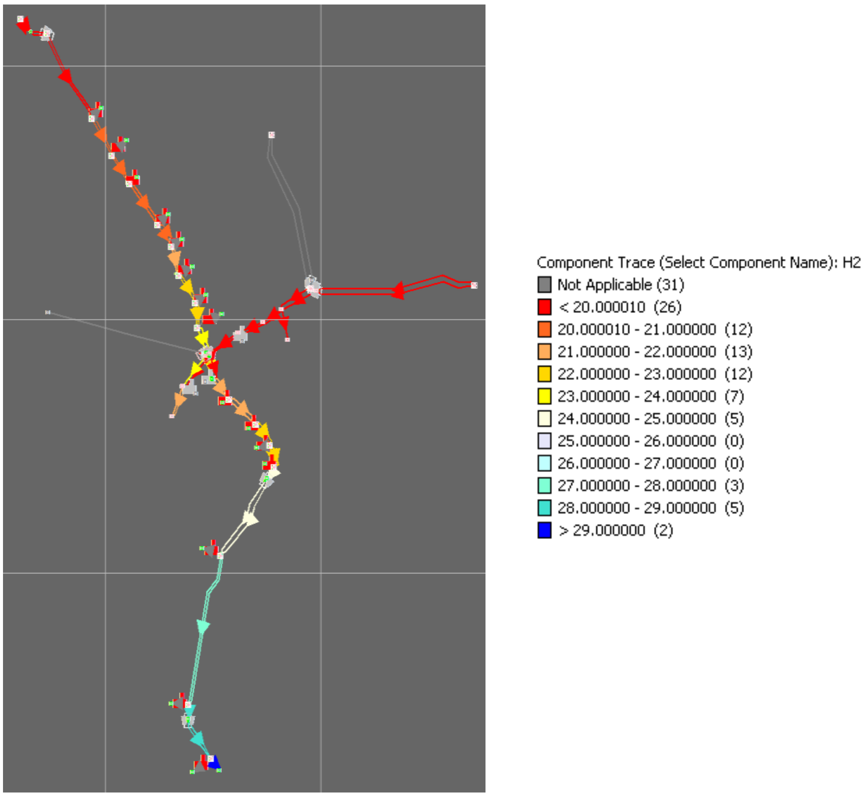


Figure 21 Example of the hydrogen concentration along the modelled grid at 20 vol-% of hydrogen at the inlet and 2 vol-% of hydrogen allowed in the permeate for the case in summer.

3.4.1.3 Comparison with other means of hydrogen transport

In contrast to section 3.3.1, where no membranes are installed, the choice of the cost-optimal transport medium is no longer quite so clear. The comparison with pipelines is no longer made because membranes are not considered in [2]. LH2 is still considered to be of little use in this case (both by truck and by ship) in a European context. There is a lack of shipping routes for transport as well as (still) a lack of demand that would justify liquefaction (and the associated energy expenditure). This leaves "only" transport by truck in the form of compressed gas or as LOHC. However, the situation must be considered in a differentiated way. If we compare Table 8 with Figure 10 , we see that there is a large overlap in the range of transport costs.

Table 8: Costs comparison of different forms- and means of hydrogen transport including separation

Form	Mean of transport	€/MWh/1000km[12]	Source
CGH_2	Pipeline	10.9 – 47.3	WP5 HIGGS
CGH_2	Truck	17 - 43	[2]
LH_2	Ship	> 15	[2]
LH_2/LOHC[13]	Truck	24 - 97	[2]

Transport in summer via pipelines tends to be somewhat cheaper than transport by truck, but only if the quantities are appropriate. In the calculated cases, this is the case with more than 20% hydrogen by volume in the pipelines. However, if larger quantities of hydrogen have to be transported, as in winter, the truck seems to be more suitable. The investments required for membranes are simply too high and have a correspondingly negative effect on transport costs.

[12] Assuming Dollar to Euro parity

[13] *Even though LOHC is cheaper than LH2 for long distance trucking, it is less likely to be used than the more commercially developed LH2* [2].

3.4.2 Technology diversification

For this last case it is now assumed according that vast amounts of hydrogen are available, transported and used throughout the grid. Part of the natural gas from the north is supplied with an admixture of 20 H_2 vol.-%. On the other hand, natural gas from the East contains up to 10 H_2 vol.-%.

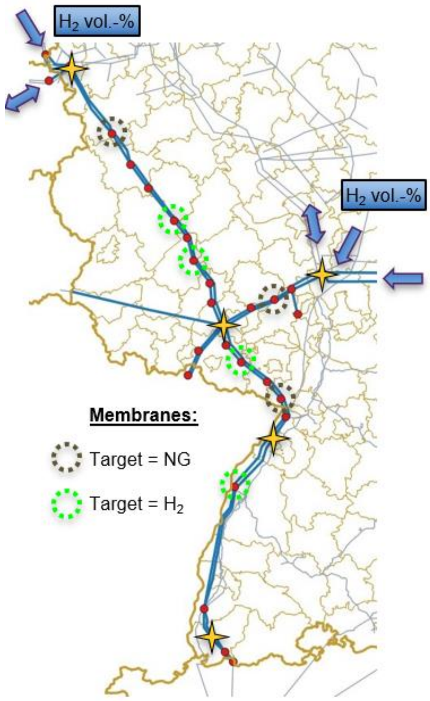


Figure 22: Case 2.3: Technology diversification

As Figure 22 shows, depending on the location respectively customer, the target product (hydrogen or natural gas) is different. Hence separation technology like membranes need to be installed. Further, the target product from the separation is reinjected into the grid. Allowed concentration of hydrogen in the permeate is 2 and 10 Vol-%

A full description of the case is given in D5.2 of HIGGS as case 2.3 (section 3.2.2.2)

3.4.2.1 Levelized cost for hydrogen transport

Along the TENP axis of the modelled section, only 6 membranes were installed compared to section 3.4.1. 4 units for the separation of hydrogen and 2 units for the separation of methane. It is not surprising that if membranes are only installed where it is really necessary, the costs for the transport of hydrogen is significantly reduced. Figure 23 shows, at least for the summer, transport costs in the same order of magnitude as if no membranes were used at all. However, they are still 1.3 - 1.4 times higher. For winter, the differences are much greater and in the range of 1.8 - 2.1 times greater. However, a network converted in this way would have to be designed for the worst case, which in this case would be winter. This would mean that the grid would be oversized for summer, which would also increase the costs in summer somewhat. Otherwise, the same effects on costs can be seen here as already described in section 3.4.1.1.

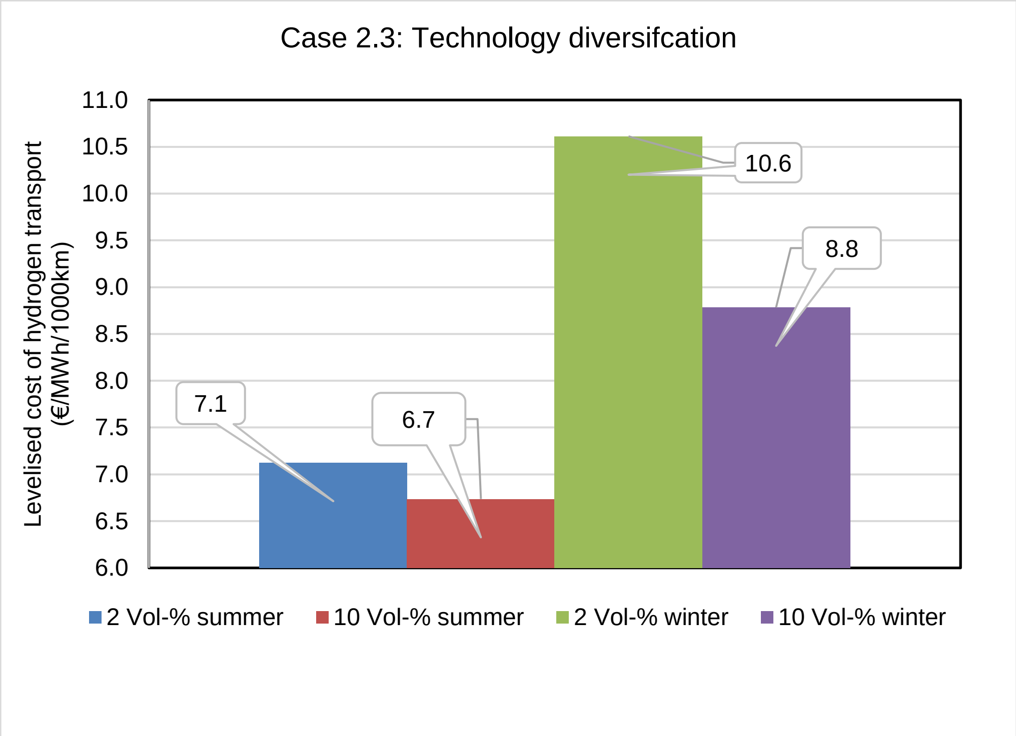
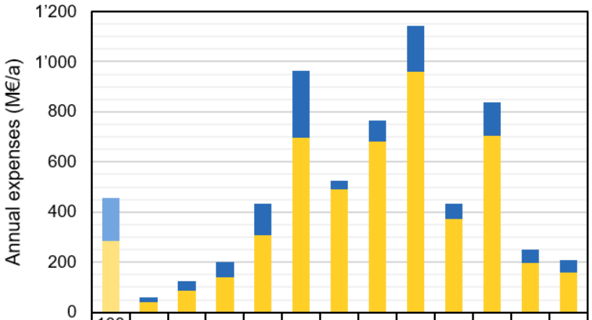


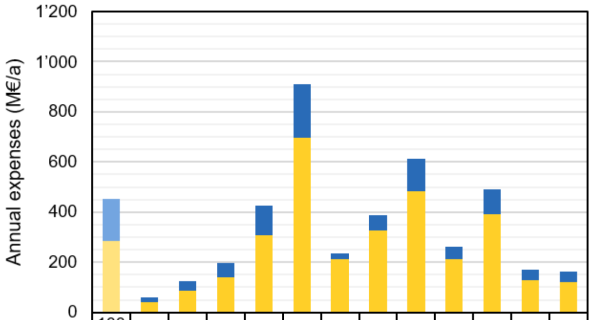
Figure 23 Levelised costs for hydrogen transport with diversified technology usage

Figure 24 shows how the annual expenditures for the hydrogen network compare to the other cases. It should be noted, however, that the annual expenditure tends to increase with the permitted share of hydrogen in the natural gas grid. However, these recurring costs can be distributed over more hydrogen (more energy), which means that the transport costs per quantity of hydrogen tend to become lower. However, Figure 24 makes it clear once again that the targeted use of membranes reduces the costs to such an extent that they are comparable with the cases where no membranes are used at all. At least for the cases that allow a proportion of 20-30 vol-% (212 and 213).



	100 (as-is)	211	212	213	214	215	221	222	223	224	225	231	232
OPEX	173	18.	37.	60.	126	264	33.	82.	183	60.	132	53.	49.
CAPEX	284.	41.2	87.3	140.	308.	697.	491.	682.	959.	373.	704.	197.	160.

computed use-cases (winter)



	100 (as-is)	211	212	213	214	215	221	222	223	224	225	231	232
OPEX	167	18.	36.	58.	118	211	23.	62.	128	50.	99.	43.	42.
CAPEX	284.	40.6	86.8	140.	307.	697.	210.	325.	482.	211.	392.	127.	119.

computed use-cases (summer)

Figure 24 Annual expenses in (M€/a) across all computed cases compared for both summer and winter. 211-215 (premixed gases) without membranes. 221-225 (moderate use H_2) and 231-232 (technology diversification) with membranes

3.4.2.2 Gas composition in the grid

If the use of separation technology is diversified and membranes are used in a targeted manner, it is advisable to investigate how the concentration of hydrogen behaves along the grid. The main aim is to determine whether there is a local accumulation of hydrogen due to the high demand for natural gas or methane further upstream. This is important because the network needs to be modified to accommodate the maximum concentrations that occur. However, this does not have to be the same everywhere. The costs for hydrogen transport can be reduced accordingly through targeted retrofitting according to the requirements of individual sections.

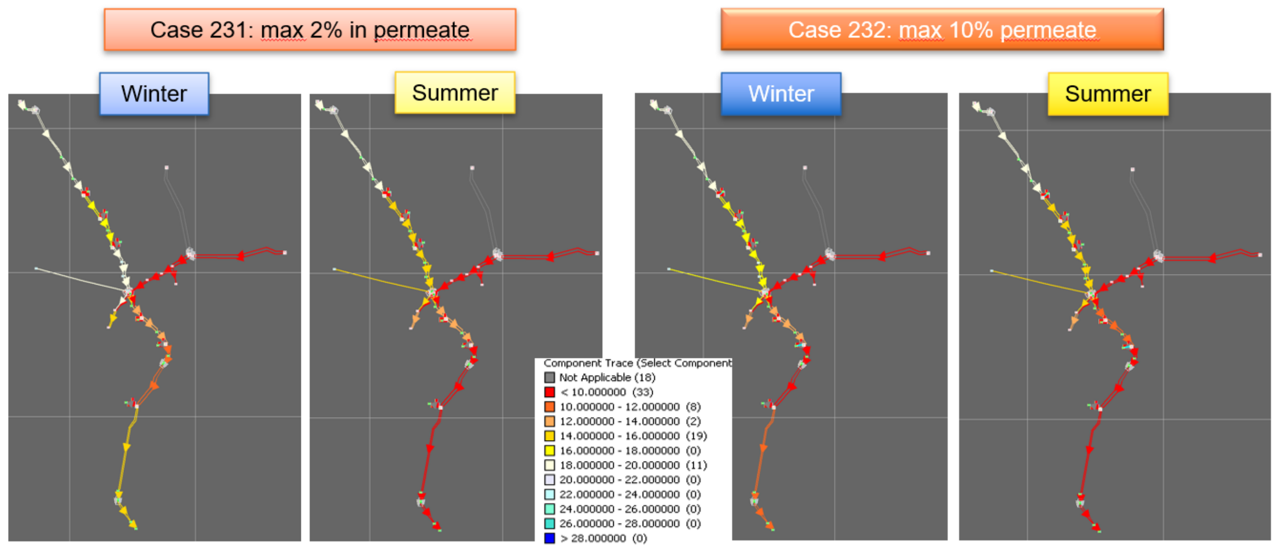


Figure 25 Example of gas composition in the grid in the case of technology diversification during winter and summer for different levels of hydrogen allowed in the permeate. Local accumulation can occur as case 231 in winter shows.

The hydrogen concentrations along the network depend on the concentrations at the inlets and thus give a first indication of the order of magnitude of the concentrations further downstream.

3.4.2.3 Comparison with other means of hydrogen transport

Figure 10 is used again for comparison and summarised in Table 9 with this use case as an example. The comparison with the pipelines is again skipped because no membranes are considered in [2] and it is a pure hydrogen grid.

Table 9 Costs comparison of different forms- and means of hydrogen transport considering technology diversification

Form	Mean of transport	€/MWh/1000km[14]	Source
CGH_2	Pipeline	6.7 – 10.6	WP5 HIGGS
CGH_2	Truck	17 - 43	[2]
LH_2	Ship	> 15	[2]
LH_2/LOHC[15]	Truck	24 - 97	[2]

This example shows once again that the transport of hydrogen through a converted natural gas grid can make sense through the targeted use of membranes. It can not only be competitive, but even the most cost-effective solution. However, it is difficult to make a final statement, as the result depends on many local conditions, such as the demand for natural gas and/or hydrogen or the locally permitted hydrogen concentration in the natural gas grid.

[14] Assuming Dollar to Euro parity

[15] *Even though LOHC is cheaper than LH2 for long distance trucking, it is less likely to be used than the more commercially developed LH2* [2].

4 Key findings on potential and enablers

4.1 Retrofitting European natural gas grid

As a first option, pure hydrogen networks could be developed in parallel and alongside the natural gas network. Existing long-term gas supply and transport contracts do not seem to prevent the development of a hydrogen backbone based on reused natural gas pipelines by 2040 in most EU Member States [3]. Should it be necessary in the future to interconnect large volumes of hydrogen production and demand centers over long distances, where hydrogen consumers are far from large hydrogen supplies from renewable sources, transport via pipelines seems to be much cheaper compared to transport by truck or ship, as some results in [12] suggests.

However, when retrofitting the natural gas grid in view of a new hydrogen market, security of supply for existing natural gas demand must also be ensured during the transition phase. The following conditions should be fulfilled for a conversion to hydrogen to be considered a viable option:

- Existence of (parallel) natural gas pipeline networks, at least parts of which could be converted to transport hydrogen.
- Ensuring natural gas supply to consumers during and after the conversion of a network section. This means that free capacities for natural gas transport or alternative supply routes should be available in the affected network section.
- Acceptance of the hydrogen market in the regions serving this hydrogen corridor.
- The supply of clean hydrogen should develop synchronously with the development of demand.

When and where these conditions will be met across Europe, and whether they will be met at all, is currently completely unclear. The timetable for the conversion of natural gas pipelines to a high hydrogen content would largely depend on the development of the hydrogen market (production and demand) in each individual region. Given the uncertainties in this phase of hydrogen development, market commitments and market interest should provide the incentives for the repurposing of networks to hydrogen and not the other way around, in order to avoid the risk of stranded as-sets. The reallocation of gas infrastructure should always be based on the principles of cost-effectiveness and cost-efficiency and benefit energy consumers. Against this background, investment decisions on the reallocation of gas infrastructures should be taken prudently and without regret, and should be based on credible scenarios for the development of the hydrogen market [1].

At the end of the day, it is currently hard to give an exact figure of what the conversion of the entire existing European gas grid would cost. The regional differences in supply and demand, both for natural gas and hydrogen, are currently so significant that only a local analysis of the situation really makes sense and allows a well-founded statement.

4.2 Cross border transport

What is currently still a considerable obstacle to the cross-border transport of hydrogen are the permitted, non-harmonised hydrogen concentrations in the mixture with natural gas. This means that not only energy-intensive separation technologies have to be installed at the border crossings, but also measuring equipment that ensures the permitted gas quality. This is exacerbated by the need for redundancy of the equipment just mentioned in order to maximise the availability of the network and minimise outages.

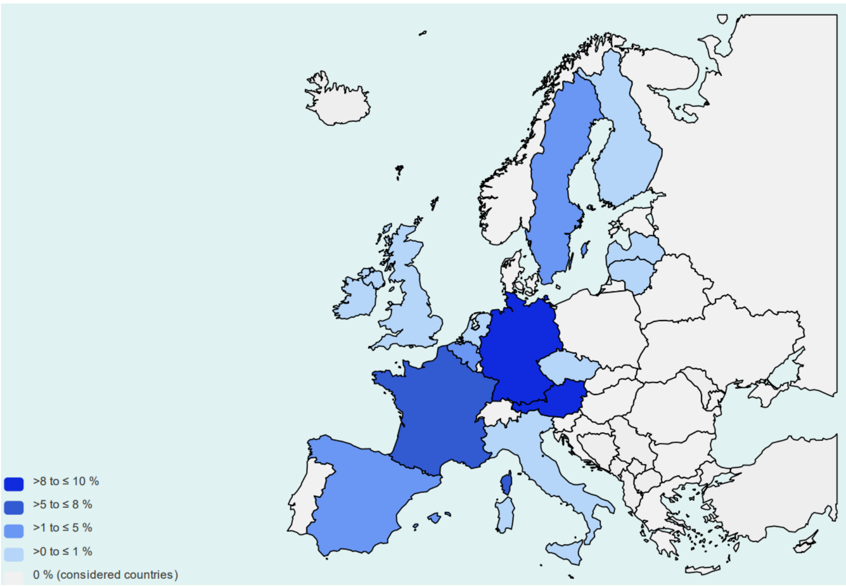


Figure 26 Allowed hydrogen concentration for blends with natural gas in the transmission gas grid of the European countries incl. UK [HIGGS D2.3]

Figure 26 shows the currently allowed hydrogen concentrations in blends with natural gas in the different EU member countries. It can be seen, that in 14 countries it is possible to have hydrogen in the transmission natural gas grid. On the other hand, the allowed concentrations in some of these countries are very low. Countries like Germany, Austria, France, Spain have allowed concentrations between 5 to 10 Vol-% and in some of these countries further adjustments to raise this limit to up to 20 Vol-% are ongoing (as in Germany for example). In other countries there is no opportunity for the injection or the transport of hydrogen reported at all [HIGGS D2.3]

4.3 Energy price development

As already shown in this report, the transport of hydrogen, especially when using membranes, is an energy-intensive process. Even if the OPEX share of the total expenses, as shown in Figure 20, is only small, it should not be disregarded. In section 3.1.3 it was shown that the model does not react very sensitively to the energy price, but this can quickly lead to additional costs in the millions for individual TSOs.

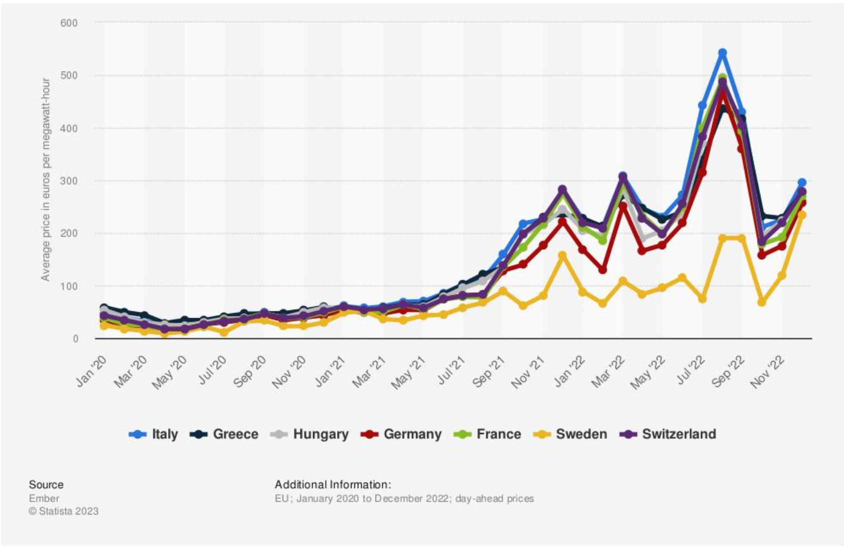


Figure 27 Average monthly electricity wholesale prices in selected countries in the European Union (EU) from January 2020 to December 2022 [10]

In the past almost 2 years, Europe has seen a strong increase in energy prices, as Figure 27 shows. Since it is impossible to predict the development in the coming years, special attention must be paid to energy prices. As energy prices rise, the permitted volume share of hydrogen in the grid would also have to increase. This would then make it possible to dampen the additional costs due to the higher supply of hydrogen.

The reasons for price fluctuations can be manifold and complex in nature, as the upcoming example from [5] show. High energy commodity prices, especially gas (marginal fuel setting the wholesale electricity prices in most regions), supported unprecedented high prices and volatility in Q3 2022. Low nuclear fleet availability and reduced hydro output, increased the pressure on the already tight market. The largest year-on-year price increases in Member States were registered in France (+342%), Austria (312%), and Slovakia (+310%). Prices in France were influenced by low nuclear generation that led to net imports from other European markets. The European Power Benchmark was 339 €/MWh on average in Q3 2022, 222% higher on yearly basis. Prices rose considerably in almost every market in Europe (price changes ranged from 25% to more than 300%). The highest prices during the quarter were recorded in Italy and Malta (472 and 460 €/MWh, respectively) and were 279% and 238% higher than in Q3 2021.

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5 Conclusions and Outlook

Based on Task 5.2, in which the model was developed both technically (numerical model of the gas grid) and economically (computing of costs for retrofit of grid components), it was possible to investigate various scenarios regarding transport costs of hydrogen and gas composition along the grid. The scenarios were mainly examined regarding the levelised transport costs for hydrogen. This allowed a comparison of the scenarios among each other. Hence, a first set of key findings on potential and enablers was compiled in this report.

It turned out that the question of whether hydrogen can be transported cost-efficiently in a mixture with natural gas or methane in a retrofitted natural gas grid can't be answered unambiguously. The answer depends above all on the following:

- The permitted proportion of hydrogen in the mix with natural gas at the transport level within a network section
- Whether and how many membranes must be used within the network section to
    a.) Ensuring a certain gas quality at distribution level
    b.) To transport hydrogen also across borders if no harmonised hydrogen shares in the mix are defined EU-wide.
- What other means of transport are available in the region under investigation
- Seasonal differences in the absolute amount of hydrogen fed into the grid and transported

The costs calculated with the model developed in this project are certainly in the same order of magnitude as suggested by other studies and are therefore considered plausible:

- approx. **3-5 €/MWh/1000km** without consideration of membranes
- approx. **11 - 47 €/MWh/1000km** considering membranes at all city gates
- approx. **7 - 11 €/MWh/1000km** considering the targeted use of membranes

This first set of key findings on the potential and enablers from Task 5.3 will be further elaborated with the other partners of this WP in the coming period. The aim will be to compile a set of recommendations that will provide a basis for decision-making for all stakeholders involved. A first direction will be given by the MS20 report in M39. This in turn will be further elaborated into D5.4, which will conclude the activities in WP5 in M42.

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