Energy Policy 180 (2023) 113641

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Designing a future-proof gas and hydrogen infrastructure for Europe – A modelling-based approach

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ARTICLE INFO

Keywords:
Electrification
Hydrogen and gas infrastructure
Modelling
European Union

ABSTRACT

Hydrogen has been at the centre of attention since the EU kicked-off its decarbonization agenda at full speed. Many consider it a silver bullet for the deep decarbonization of technically challenging sectors and industries, but it is also an attractive option for the gas industry to retain and future-proof its well-developed infrastructure networks. The modelling methodology presented in this report systematically tests the feasibility and cost of different pipeline transportation methods – blending, repurposing, and dedicated hydrogen pipelines - under different decarbonization pathways and concludes that blending is not a viable solution and pipeline repurposing can lead to excessive investment outlays in the range of EUR 19–25 bn over the modelled period (2020–2050) for the EU-27.

1. Introduction

The European Union is committed to fully decarbonise its energy sector, including heating and cooling in buildings and industry, in order to arrive at a net-zero GHG emissions economy by 2050 (European Commission, 2019). The political goal is thereby established, with climate concerns and long-term environmental goals successfully negotiated and agreed to. This grand compromise, however, does not point to a single solution on how the goal should be achieved.

Electrification is widely considered the central solution for the decarbonization of space heating, but there is also a consensus that hydrogen and renewable gases will play an important role in the decarbonization of the energy system. The new technologies are meant to replace well-established value chains, first and foremost fossil fuels: oil, coal, and natural gas. Oil has already been largely removed from Europe's energy sector while coal has been significantly drawn down over the past two decades, replaced by renewables and natural gas in the merit order curve of European electricity production. By the end of the 2010s, EU governments were announcing coal phase-out deadlines. Natural gas, however, did not see such a development path. For a long time, natural gas has been treated as a bridging fuel in the energy transition and a full phase-out was never envisaged; to the contrary, a temporary rise in gas consumption was foreseen to substitute for coal (IEA, 2011).

The pledge to transition to a fully decarbonized economy by 2050 has made investments into natural gas infrastructure less attractive and the bankability of new natural gas projects problematic. Financial institutions like the European Investment Bank have withdrawn from major infrastructure financing. However, it is not only the gas industry but also policymakers in agreement that natural gas is indispensable to the EU energy system over the next decade. In fact, gas power plants under 100 g CO_2e/kWh were included in the European green taxonomy. The EU hydrogen strategy acknowledges the wide gap between the cost of decarbonized gases and imports. It envisages an aggressive reduction in electrolyser costs over the next decades (European Commission, 2020). The demand for hydrogen is, however, far more difficult to predict. Due to the energy efficiency losses in the production of green hydrogen, a consensus has emerged that the so-called "hard to abate sectors" like the chemicals and steel industry, where direct electrification is not possible, should be prioritized. Meanwhile, there are strong

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https://doi.org/10.1016/j.enpol.2023.113641
Received 29 July 2022; Received in revised form 4 May 2023; Accepted 18 May 2023
Available online 12 June 2023

Table 1
Summary of studies on hydrogen infrastructure.

Author/year	Study title	Stakeholder type	Coverage	Methodology	Focus	finding
Guidehouse (2021)	Extending the European Hydrogen Backbone	Gas TSOs	21 EU countries	Cost minimisation along the value chain	Natural gas and hydrogen networks	43-81 billion € investment need up to 2040, 39700 km
(Agora Energiewende and AFRY Management Consulting, 2021)	No-regret Hydrogen: Charting Early Steps for Hydrogen Infrastructure in Europe	Think tank	EU27 + UK + NO and MENA region	Cost minimisation along the value chain	industrial demand for hard-to-abate sectors	Only a few hydrogen corridors are identified; hydrogen is used by industry and production should be close to consumption
Fischer et al. (2020)	Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure	EC	EU27	scenario based modelling	infrastructure	The hydrogen scenario is cheaper than electrification for overall systems costs
Vautrin et al. (2021)	METIS study on costs and benefits of a pan-European hydrogen infrastructure	EC	EU27 + UK + NO	Integrated gas-hydrogen-electricity market modelling	Infrastructure, sector coupling	Must set up a pan-European hydrogen transport infrastructure by 2030 for best economic outcome
Koirala et al. (2021)	Integrated electricity, hydrogen and natural gas system modelling framework: Application to the Dutch Infrastructure Outlook 2050	Gas and electricity TSOs of NL	NL	Integrated gas-hydrogen-electricity market modelling (Linear programming assuming perfect competition)	Electricity, hydrogen, and gas markets; sector coupling	Hydrogen and biomethane can provide flexibility for RES-E in the future energy system
Aunedi et al. (2022)	Multi-model assessment of heat decarbonization options in the UK using electricity and hydrogen	Engineering research Council	UK	Soft-linked electricity, gas, and hydrogen models, cost minimisation	Electricity, hydrogen and gas markets; sector coupling	Electrolysis-based hydrogen generation is not cost-competitive with CCS SMR. Hydrogen is needed to supply peak heat demand. Electrification is the most cost-competitive option.
Gils et al. (2021)	Interaction of hydrogen infrastructures with other sector coupling options towards a zero-emission energy system in Germany	German Ministry of Economic Affairs	DE and neighbouring countries	Integrated gas-hydrogen- electricity market modelling (Linear cost minimisation)	Electricity, hydrogen and gas markets; sector coupling	Hydrogen can support balancing in electricity and significant infrastructure investment is required to achieve carbon neutrality
ACER (2021b)	Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure:	Regulators	EU27	Overview of existing studies and reflections on the conditions for repurposing	technical gaps, costs	no consensus on the size and need for repurposing of gas pipelines for hydrogen transport
Blanco et al. (2022)	A taxonomy of models for investigating hydrogen energy systems	IEA	–	Review of 29 studies on hydrogen network modelling	Review	Hydrogen models can be categorised into 9 archetypes; high techno-economic focus in modelling.
Wachsmuth et al. (2021)	The potential of hydrogen for decarbonising EU industry	European Parliament	EU27	Literature review and expert interviews	Industry	Hydrogen will be need for hard-to abate sectors and industrial sector will help the formation of a backbone
Breitschopf et al. (2021)	The role of H2 import & storage to scale up the deployment of renewable H2	European Commission	EU27	Scenario based cost comparison of hydrogen import	Supply gap of hydrogen demand and production in the EU	Closer regions (MENA, UA) have cost advantages to produce hydrogen for the EU

opponents of hydrogen applications in the heating and transportation sectors (Agora Energiewende and AFRY Management Consulting, 2021; Rosenow, 2020). With the long-term decline of European natural gas demand, there is growing interest in studying how the well-developed gas infrastructure could be utilised to transport or store other gases, most notably hydrogen, to fit into decarbonization plans. Outside of hard-to-abate sectors, the main argument for keeping gases in the energy mix is to serve as balancing for renewables, the advantage of gas storage over battery storage, and the advantage of transportation cost of gas over that of electricity. (European Commission, Directorate-General for Energy, 2018; Frontier Economics, 2019; Navigant, 2019; European Climate Fondation, 2019).

The first consideration for the use of existing natural gas infrastructure as a carrier for hydrogen is the blending with natural gas. There are currently several ongoing projects testing the technical feasibility of blending. Most studies agree that to avoid damage to pipelines the hydrogen content of the gas mix should not exceed 10–15%, which would certainly limit the gas transmission grid for hydrogen transport (ACER, 2020). In the long-term, steel gas pipelines could be gradually repurposed to enable their use for the transportation of pure hydrogen. There are, however, major uncertainties around the development of the hydrogen market for both production and demand and the need for transport between these two. Therefore, repurposing should closely follow the market requirements to avoid unnecessary investments and stranded costs. Another option is the gradual build-out of a dedicated 100% hydrogen network from isolated hydrogen valleys to an interconnected internal market of (ACER, 2021b).

The objective of this report is to assess the impact of varying levels of heat electrification on natural gas and hydrogen grid infrastructure using quantitative modelling under three technical scenarios to determine the investment cost required for natural gas and hydrogen infrastructure: 1. direct electrification via use of renewable electricity; 2. indirect electrification via hydrogen, and 3. e-fuels[1] (synthetic gases) produced from renewable electricity.

This study covers the EU-27 Member States with a timeframe until 2050.

The paper begins with a short summary of the policy background followed by a review of the literature on hydrogen infrastructure modelling. Then our methodological approach is explained before the modelling results are presented. It concludes with a discussion of general lessons from this modelling exercise and policy recommendations.

2. Literature review

In 2020 several European gas TSOs commissioned a detailed study – the so-called Hydrogen Backbone study – (Guidehouse, 2021) aiming to show a possible future role for existing gas networks with a vision for the future European hydrogen supply infrastructure. The study found that it is more economical to repurpose existing natural gas networks and add dedicated hydrogen pipelines only in the absence of gas infrastructure.

Agora Energiewende, a think tank supporting decarbonization goals, together with AFRY management consulting (2021), concluded that the need for no-regret hydrogen infrastructure is much less than the gas industry finding in the Hydrogen Backbone study. Furthermore, they suggest that instead of repurposing existing natural gas pipelines, 100% dedicated hydrogen pipelines should directly connect production to industrial consumption centres. The European Commission Directorate-General for Energy ordered a study (Fischer et al., 2020) comparing the total system cost of three distinct pathways: electrification, hydrogen, and e-fuel-dominated scenarios. It concluded that the hydrogen scenario offers the lowest total system cost despite the larger RES investment requirements and efficiency losses of hydrogen transformation. Table 1 below summarizes the most relevant publicly available studies on the future of hydrogen networks in Europe.

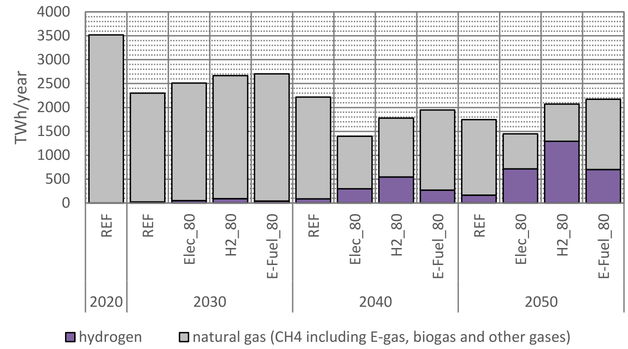

Fig. 1. Natural gas (including biomethane and biogases and e-methane) and hydrogen demand (EU-27).

Our paper contributes to this rich and quickly expanding literature by introducing a simple decision algorithm on hydrogen network investments that accounts for the interplay with natural gas networks. Contrary to integrated co-optimisation models, this framework highlights the ownership 'dilemma' – hydrogen and natural gas networks and production facilities have different owners – which can lead to alternate outcomes due to the lack of a central planner.

3. Methodology

In this study, we use a quantitative model-based scenario analysis to determine the investment levels required for gas infrastructure under different scenarios. To start, we establish a reference scenario for the modelling of heat supply taking into account current policies and targets without any further increase in decarbonization ambition (i.e. "business-as-usual"). This is mostly based on a preliminary version of the EU Commission's PRIMES reference scenario 2020 (European Commission, 2021). The reference case is used as the basis for comparative analysis against the three modelled technology scenarios determining the production and consumption levels of hydrogen, natural and other gases to reach EU decarbonization targets.

- Direct electrification scenario (Elec_80)
- Hydrogen scenario (H2_80)
- E-fuels scenario (E_fuel_80)

None of these technology-focused scenarios are 100% "pure" scenarios, but represent dominant shares of the main technologies (electrification, green hydrogen or synthetic gas) in the respective scenarios. Across all scenarios in the Results section, 80% of the heated floor area of buildings is heated by the respective 'target' technology (RES-E, hydrogen, or synthetic biofuels). For example, 80% of the floor area heating in scenario Elec_80 is derived from renewable electricity. While the "target" technology is kept within the scenario constraints, the remainder is filled with a mix of the other technologies according to a cost-minimisation approach. These modelled scenarios are based on a joint modelling project called "Electrification of the heating sector"[2] carried out jointly by Fraunhofer, TU Wien, Consentec and REKK for the European Commission. For the natural gas and hydrogen infrastructure modelling exercise herein, hydrogen demand and production are inputs from other modelling exercises.

Fig. 1 summarizes the natural gas (fossil methane, biogases,

[1] The term "e-fuels" in the scenario names will be used throughout this paper as synonym for synthetic, hydrocarbon-based gases produced based on electricity from RES.

[2] A project for the European Commission under Tender ENER/C1/2019-481.

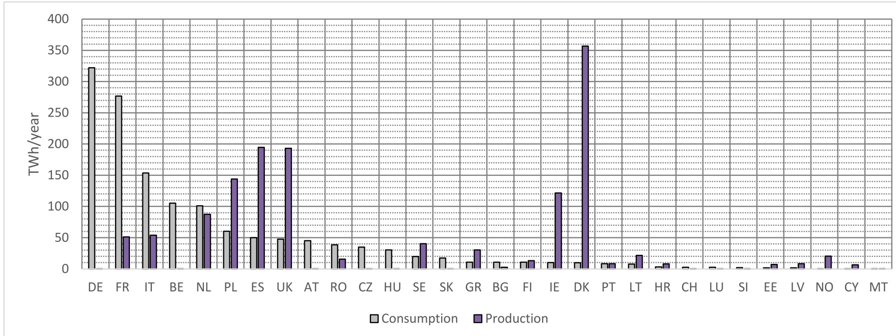

Fig. 2. EU 27 hydrogen consumption and production for the Hydrogen 80 scenario in 2050, TWh/year.

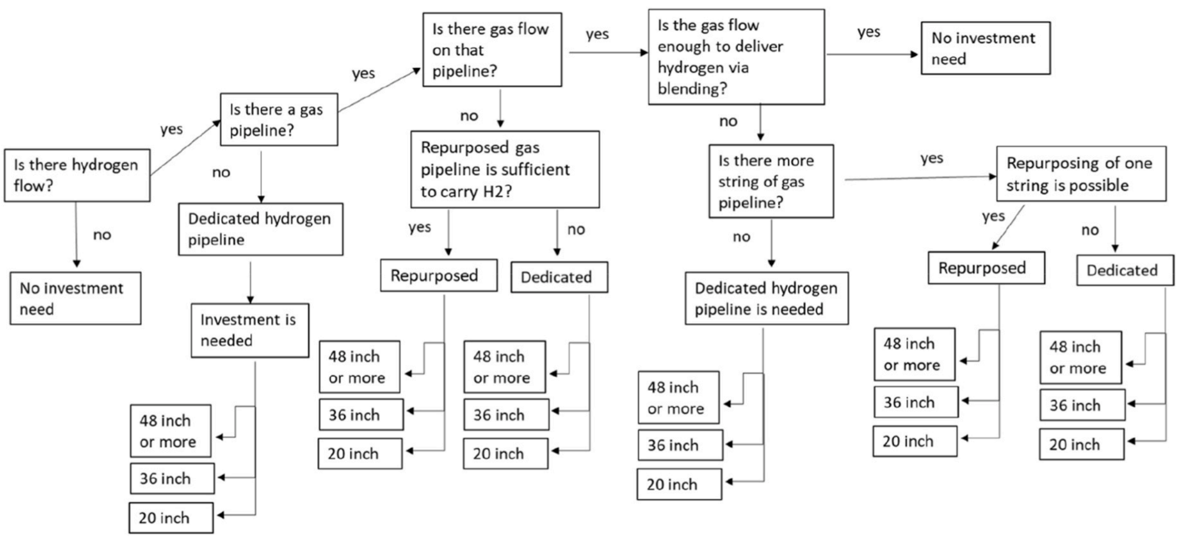

Fig. 3. Hydrogen investment decision tree.

biomethane, e-methane) and hydrogen demand in the EU27. From this, two main 2050 trends can be identified: (i) gas demand will fall by around 50% (from 3500 TWh/year to 1500–2000 TWh/year) (ii) the share of natural gas demand will drop significantly from current levels above 90% and the share of hydrogen will increase to 30–60% in the gas demand.

The input dataset meets all hydrogen demand with EU sources, hence no import is needed from third countries. However, demand and production of hydrogen is distributed unevenly among the modelled countries, illustrated by the Hydrogen 80 scenario for 2050 in Fig. 2. The different locational nodes of demand and supply must be connected, requiring additional network investments. Detailed hydrogen demand and supply data for all scenarios is provided in the data documentation.[3]

The EGMM gas market and transmission infrastructure model is used to estimate the investment levels required for additional natural gas and hydrogen infrastructure. The EGMM is a competitive, multi-market equilibrium model that simulates the operation of the wholesale natural gas market across the whole of Europe. It includes a supply-demand representation of 35 European countries, including gas storage and transportation linkages. Large external markets, including Russia, Turkey, Libya, Algeria and LNG exporters are represented exogenously with market prices, long-term supply contracts and physical connections to Europe. The timeframe of the model covers 12 consecutive months, starting in April. Market participants have perfect foresight over this period and dynamic connections between months are introduced by the operation of gas storages and take-or-pay constraints of long-term contracts.

Given the input data, the model calculates a competitive market equilibrium for the modelled countries, where all arbitrage opportunities across time and space are therefore exhausted to the extent that storage facilities, transportation, infrastructure, and contractual conditions permit. As a result, the competitive equilibrium yields an efficient outcome and can be equivalently computed to solve a constrained welfare maximization problem. The equilibrium is determined by solving the first-order linear complementarity conditions using an MLCP algorithm. A detailed description of the model can be found in Kiss et al. (2016) and (Kotek et al., 2023). This model has been widely used for infrastructure evaluation modelling (Kotek et al., 2019; Selei and Takácsné Tóth, 2022).

The ENTSOG capacity map is used as the basis for the EGMM gas transmission input data set. Additionally, advanced gas infrastructure projects from TYNDP 2020 are included into the base gas grid. The analysis only accounts for cross-border transmission pipelines; internal pipelines are not represented in the model. Since natural gas demand does not increase in any scenario, no additional investment for natural gas infrastructure is foreseen. The hydrogen infrastructure-development is defined by the need for hydrogen transport across country nodes along the interconnected natural gas network system as well as potential new dedicated hydrogen pipelines. The network must be able to carry both the natural gas and hydrogen trades; natural gas and hydrogen transmission grid expansion requirements are modelled separately and soft-linked. The EGMM-Hydrogen model is essentially a simplified version

[3] For all underlying data included in the analysis consult https://doi.org/10.5281/zenodo.7588981.

Table 2
Total investment need of the hydrogen network, bn EUR/yr (EU-27).

		2020–2030	2030–2040	2040–2050	Total
REF	**bnEUR**	0.0	0.0	0.0	0.0
Elec_80	**bnEUR**	12.3	2.6	3.9	18.8
H2_80	**bnEUR**	16.8	3.1	4.9	24.7
E-Fuel_80	**bnEUR**	12.9	4.1	3.6	20.6

OPEX is derived from accumulated CAPEX costs applying a 3% flat rate. By 2030, the hydrogen network OPEX is EUR 0.5 bn/year, increasing to EUR 0.6–0.7 bn/yr thereafter (Table 3). In this sense, OPEX is financing non-flow-related costs.

Table 3
Hydrogen network OPEX, Bn EUR/yr (EU-27).

		2020–2030	2030–2040	2040–2050
REF	**bnEUR**	0.4	0.5	0.6
Elec_80	**bnEUR**	0.4	0.4	0.6
H2_80	**bnEUR**	0.5	0.6	0.7
E-Fuel_80	**bnEUR**	0.4	0.5	0.6

of the EGMM, using the same mathematical algorithm with a hydrogen input dataset. LNG facilities and long-term natural gas contracts are excluded from the model as is LNG terminals repurposing for hydrogen which is outside the scope of this paper. Long-term legacy take-or pay contracts are important for the natural gas market but currently there is no information on the future development of hydrogen contractual arrangements. Gas storage, meanwhile, is considered to have potential for hydrogen storage. The geographical coverage of the EGMM-Hydrogen model is EU-27 enlarged with Switzerland, Norway and UK. Interconnections are assumed between all nodes (countries) with transport costs reflecting the geographical distances between nodes (see Annex). A uniform hydrogen production cost of 60 €/MWh is assumed for all countries. Hydrogen pipeline infrastructure is based on the current natural gas network and external connections beyond the geographical coverage of the modelling are not included. The modelling identifies the least-cost option for hydrogen transportation by setting distance-based tariffs for each potential connection between national consumption nodes. Tariffs were calculated based on the distance between country nodes using a unitary transport cost. The costs between two nodes were divided according to the distance from the national border (see Tables 11 and 12).

Fig. 3 illustrates the decision process of investing into hydrogen infrastructure. First, the EGMM-Gas model was run for every modelled year to quantify the gas flows and utilization of gas infrastructure in the different scenarios, taking into account the different levels of gas demand. This shows us whether hydrogen blending or repurposing is possible, or if dedicated hydrogen pipeline investment is needed. Then the second step was using these outputs as inputs for the modified gas market model, EGMM-Hydrogen. In some cases, additional links were added for countries with existing gas pipelines to facilitate the unconstrained flow of hydrogen. The natural gas and hydrogen models were run sequentially; the need for natural gas and hydrogen networks are not jointly optimized. The results from the EGMM-Gas and EGMM-Hydrogen were then used to calculate the investment need for hydrogen infrastructure by identifying the least-cost flow pattern.

Fig. 3 shows the three possible outcomes for the hydrogen investment decision tree.

- Hydrogen blending in the gas transmission network: Capped at 5% in the modelling, hydrogen blending does not result in additional infrastructure investment. Blended hydrogen content is assumed to supply the hydrogen demand in the modelling, although currently hydrogen blends are not physically de-blended and not supplied as pure hydrogen to the end consumer.
- Repurposing exiting natural gas pipelines to hydrogen flow: Natural gas pipelines may be repurposed at a lower cost than commissioning dedicated hydrogen infrastructure. The land use rights, existing infrastructure and other factors are expected to reduce the investment costs. Compressor station investment is based on distance. Once a natural gas pipeline is repurposed, it may only be used for hydrogen transport.
- Commissioning dedicated hydrogen pipelines: When blending or repurposing is not possible, dedicated hydrogen infrastructure is required. Compressor station investment is based on distance.

Investment occurs only if there is hydrogen flow present.

- If there is no natural gas pipeline in place, the hydrogen flow may only be accommodated by a dedicated hydrogen pipeline. The pipeline capacity is determined by the volume of hydrogen transported.
- If there is natural gas pipeline in place, the presence of gas flows determines the next step.
  - o If the gas pipeline is not in use, it can be repurposed for hydrogen flows.
    - ▪ If the hydrogen flows are lower than the capacity of the natural gas pipeline, repurposing is executed, taking into account the capacity need of the hydrogen pipeline.
    - ▪ If hydrogen flows are higher than the capacity of the natural gas pipeline, a dedicated hydrogen pipeline is needed, considering the capacity need of the hydrogen flow.
  - o If the gas pipeline is used for transmission, hydrogen may be blended up to 5%.
    - ▪ If the level is below 5% of the gas flow and there is free capacity, blending is possible. No infrastructure investment is needed.
    - ▪ If the transported hydrogen volumes exceed the blending threshold or there is no free capacity for blending, there is an assessment of whether parallel gas pipeline strings may be utilised.
- If parallel gas pipeline strings are needed, then they are either repurposed or a dedicated line is commissioned.
- If there are no parallel pipeline strings, a dedicated pipeline is needed.
  - o When gas pipeline repurposing and construction of dedicated hydrogen pipelines are needed, investments are differentiated according to the cost based on the modelled flows.

Table 4
Variable system costs of the natural gas network (EU-27).

		2020–2030	2030–2040	2040–2050
REF	**bnEUR/a**	2.8	2.2	1.9
Elec_80	**bnEUR/a**	2.5	1.0	0.7
H2_80	**bnEUR/a**	2.6	1.1	0.7
E-Fuel_80	**bnEUR/a**	2.6	1.5	1.2

Table 5
Variable system costs of the hydrogen network (EU-27).

		2020–2030	2030–2040	2040–2050
REF	**bnEUR/a**	0.0	0.0	0.0
Elec_80	**bnEUR/a**	0.1	0.3	0.7
H2_80	**bnEUR/a**	0.2	0.7	1.7
E-Fuel_80	**bnEUR/a**	0.1	0.4	0.9

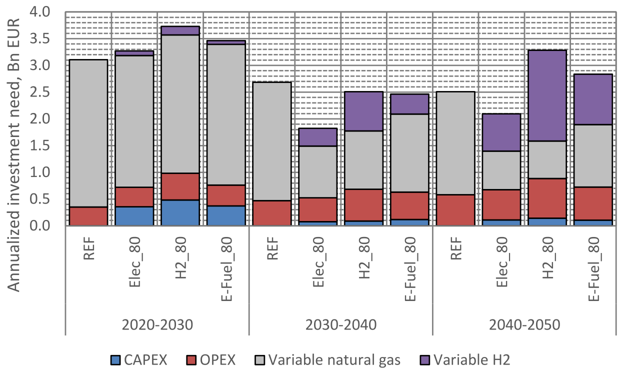

Fig. 4. Annualised CAPEX, OPEX, and variable system costs.

Table 6
Modelled CAPEX, 2020–2050 (EU-27+CH + NO + UK), Bn EUR.

	Elec_80	H2_80	E-Fuel_80		Elec_80	H2_80	E-Fuel_80
AT	0.8	1.1	1.0	IT	2.2	2.6	2.1
BE	0.6	0.6	0.6	LT	0.5	0.7	0.5
BG	0.2	0.2	0.1	LU	0.0	0.0	0.0
CH	0.4	0.7	0.2	LV	0.3	0.4	0.1
CY	0.2	0.5	0.2	MT	0.04	0.04	0.04
CZ	0.2	0.2	0.3	NL	0.9	0.9	0.9
DE	1.4	1.5	1.1	NO	1.3	1.7	1.2
DK	1.3	1.2	1.3	PL	0.9	1.1	1.9
EE	0.6	0.7	0.2	PT	0.1	0.3	0.2
ES	0.9	1.3	1.3	RO	0.3	0.8	0.2
FI	0.3	0.3	0.2	SE	1.2	1.5	1.2
FR	1.2	1.5	1.2	SI	0.5	0.5	0.5
GR	1.8	3.0	1.8	SK	0.5	1.0	0.8
HR	0.2	0.5	0.6	UK	2.3	2.3	2.3
HU	0.8	1.6	1.2	total	22.7	29.5	24.4
IE	0.8	0.8	0.8	Total EU-27	18.8	24.7	20.6

The investment cost of a hydrogen pipeline is based on the European Hydrogen Backbone study, factoring the pipeline and compressor, as well as CAPEX and OPEX (Guidehouse, 2021):

- Cost of hydrogen blending: Compressor is 0.05 m€/km CAPEX and no pipeline CAPEX.
- Cost of repurposing existing gas pipelines: 0.5 m€/km CAPEX and 0.62 m€/km OPEX.
- Cost of new dedicated hydrogen pipeline: 2.8 m€/km CAPEX and 0.62 m€/km OPEX.

The necessary length of the hydrogen infrastructure is estimated based on the distance between the central nodes in each country. The cost estimation is based on the approximate length of the hydrogen network and the utilization and flows on the joint hydrogen-gas infrastructure.

4. Results

4.1. Investment need and annualised system cost

The main focus of the modelling exercise is to quantify the investments requirements and annual costs of the joint hydrogen and natural gas systems. Due to decreasing natural gas demand, no new fossil gas pipelines are expected to be built. Gas network investment relate to repurposing existing gas pipelines to accommodate hydrogen flows, while hydrogen network investment denotes dedicated new hydrogen pipelines.

Table 7
Length and composition of hydrogen transmission pipelines (EU-27).

	Hydrogen transmission pipeline length				Repurposed natural gas transmission pipeline length				Dedicated hydrogen transmission pipeline length				Share of repurposed pipeline
	2020–2030	2030–2040	2040–2050	Total	2020–2030	2030–2040	2040–2050	Total	2020–2030	2030–2040	2040–2050	Total	Total
	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	%
REF	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0
Elec_80	11.26	3.14	4.53	18.93	6.85	2.39	3.12	12.37	4.41	0.75	1.40	6.56	65%
H2_80	12.22	3.89	3.45	19.56	6.96	3.54	1.81	12.31	5.26	0.35	1.64	7.25	63%
E-Fuel_80	11.99	3.96	2.74	18.69	7.14	2.83	1.35	11.32	4.85	1.13	1.38	7.37	61%

Hydrogen blending ranges from 0 to 7 TWh/year (Table 8), remaining far below the theoretical 5% blending threshold, thus playing a negligible role. The highest blending occurs in the 80% hydrogen scenario, equating to 7.4 TWh or 7% of the total hydrogen trade in 2030. By 2050, only 3% of the total hydrogen trade is blended. Hydrogen trade is mainly executed on repurposed or dedicated pipeline infrastructure.

Table 8
Total modelled hydrogen blending (TWh/year), (EU-27+CH + NO + UK).

	hydrogen blending, TWh/year		
	2020–2030	2030–2040	2040–2050
REF	0.0	0.0	0.0
Elec_80	2.47	0.18	–
H2_80	7.38	0.30	0.03
E-Fuel_80	5.66	0.82	2.70

The total investment into the hydrogen network ranges from bn EUR 18.8–24.7 bn (Table 2). Not surprisingly, it is the lowest in the electrification scenario, when heating demand is served mostly by electricity, and highest when hydrogen is used as a primary source of heating. Two thirds of the network is made up of repurposed gas pipelines currently in use.

Variable system costs are indicated for gas and hydrogen networks separately. These costs are derived from modelled flows on the network multiplied by the applicable network tariffs. Although the current proposal for the regulation of the European hydrogen market does not anticipate cross-border transmission tariffs, distance-based hydrogen transmission tariffs are included in the OPEX of this modelling. Likewise, (natural) gas transmission tariffs from 2020 are used as the basis for gas transmission OPEX.

Variable gas system costs comprise most of the system operation costs to 2030 (EUR 2.5–2.6 Bn) as gas flows remain high relative to total gas demand, before falling to EUR 0.7–1.2 bn in 2050 (Table 4). Variable hydrogen system costs reach EUR 0.7–1.7 bn/year by 2050 (Table 5).

CAPEX costs are annualised to allow for easy comparison between the various scenarios, so that all cost categories can be added together to represent the annual cost of hydrogen and gas transmission. The annualization of CAPEX presumes a 60-year lifetime at a 2% discount rate, resulting in a ~3% annuity factor. Up to 2030, management of the natural gas transmission network is the main cost component next to negligible hydrogen system costs. By 2050, this relation shifts. As total flows on the network fall, the total costs of maintaining the natural gas and hydrogen system are lower than or equal to current (2020) natural gas system costs. By 2050, the total costs of maintaining the natural gas and hydrogen system range from 2 to 3 bn EUR (including annualised investment costs). The costs of the hydrogen system are on par with or greater than the natural gas system by 2050 (Fig. 4).

The distribution of investment costs between countries varies between 0% and 14% of the CAPEX, the highest in Italy, usually followed by the UK and Poland. The other countries with outstanding CAPEX above 7% of the total modelled CAPEX of the region are Germany and Greece (Table 6).

4.2. Hydrogen infrastructure findings

The estimated length of the 2050 EU hydrogen transmission system is some 18,000–20,000 km, most of which needs to be in place by the first decade. The longest network is found in the hydrogen scenario. The share of repurposed pipelines is lowest in the E-fuel scenario (61%), given that nearly the same hydrogen demand is coupled with a higher synthetic gas flow (Table 7).

Table 9
Internal natural gas and hydrogen trade across European infrastructure in 2050, TWh/year, (EU-27+CH + NO + UK).

	hydrogen trade volume	natural gas trade volume	blended hydrogen trade volume	total
	TWh/year	TWh/year	TWh/year	TWh/year
REF	–	–	0.0	–
Elec_80	718	915	–	1634
H2_80	1580	878	0.03	2458
E-Fuel_80	959	1712	2.70	2674

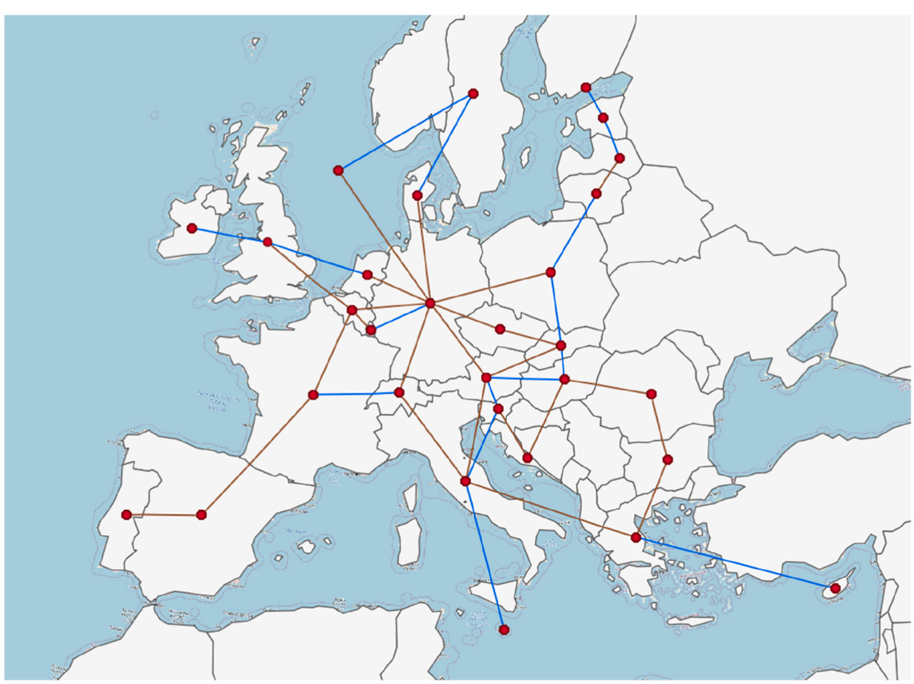

Fig. 5. 2050 hydrogen transmission infrastructure, Elec_80 scenario (blue lines: dedicated hydrogen; brown lines repurposed gas pipelines). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

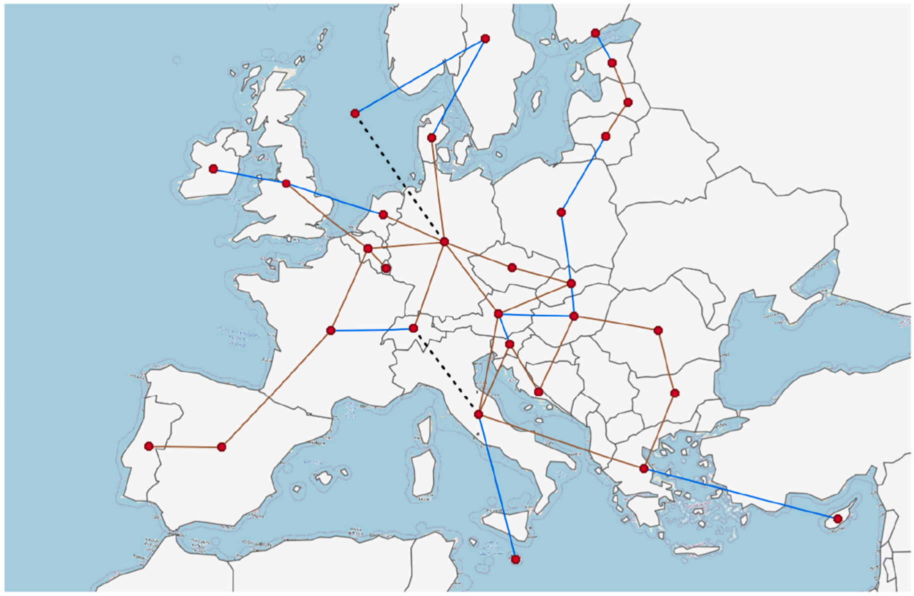

Fig. 6. Hydrogen transmission infrastructure by 2050, E-Fuel_80 scenario (blue lines: dedicated hydrogen; brown lines repurposed gas pipelines; dashed lines: blending). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

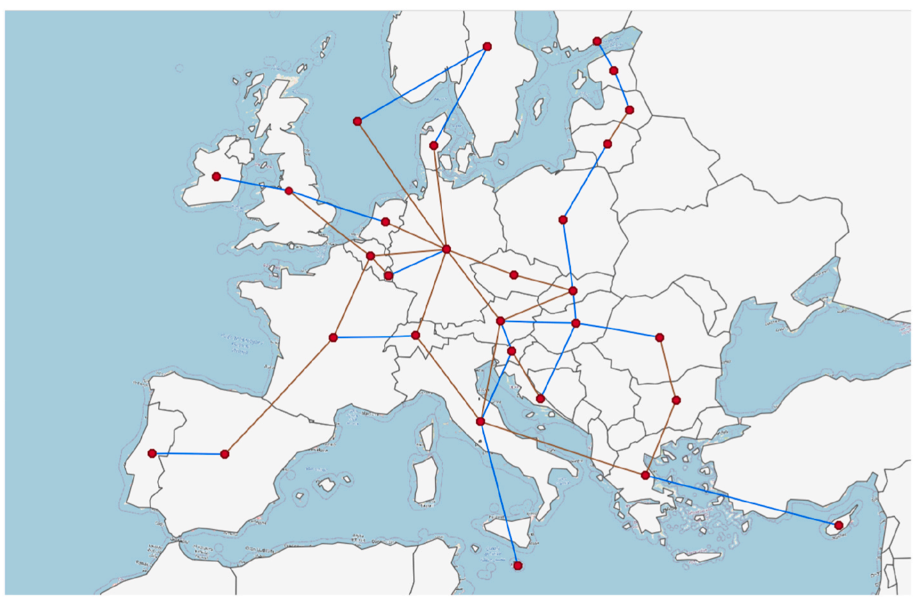

Fig. 7. Hydrogen transmission infrastructure by 2050, H2_80 scenario (blue lines: dedicated hydrogen; brown lines repurposed gas pipelines). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

By 2050, most of the fossil natural gas network will be used for transporting hydrogen and abated natural gas. In the Electrification scenario, the combined gas transmission and newly built hydrogen pipeline networks will carry 42–44% hydrogen and 56–58% natural gas. The transmission networks have a higher utilization in the hydrogen scenario, with a split of 47–64% for hydrogen and 36–53% for natural gas. The utilization rate is similar for the E-fuel scenario, in reverse, with a split of 33–42% for hydrogen and 58–67% for natural gas (Table 9).

All three scenarios require a very similar hydrogen network setup (Fig. 5, Fig. 6, Fig. 7). There are a few interconnections that are repurposing in one scenario and a dedicated pipeline in another (e.g.HR-HU and RO-HU), but it is rare that a pipeline is needed in only one scenario (e.g., PL-DE in Elec_80-scenario). By 2050, only the H2_80-scenario uses a cross-border natural-gas pipeline for blending. It should be noted that hydrogen infrastructure in the model is structured by meeting the hydrogen production and demand equilibrium inside the EU at least cost; it does not consider imports from third countries nor the cost effectiveness of hydrogen compared to alternative sources. As a result, some expensive dedicated pipelines (e.g. between Cyprus and Greece or Malta and Italy) are built into the model. The modelling only considers pipeline investments which may be replaced by hydrogen transported via ships to these target markets Therefore, the cost effectiveness of individual pipelines should be further analysed.

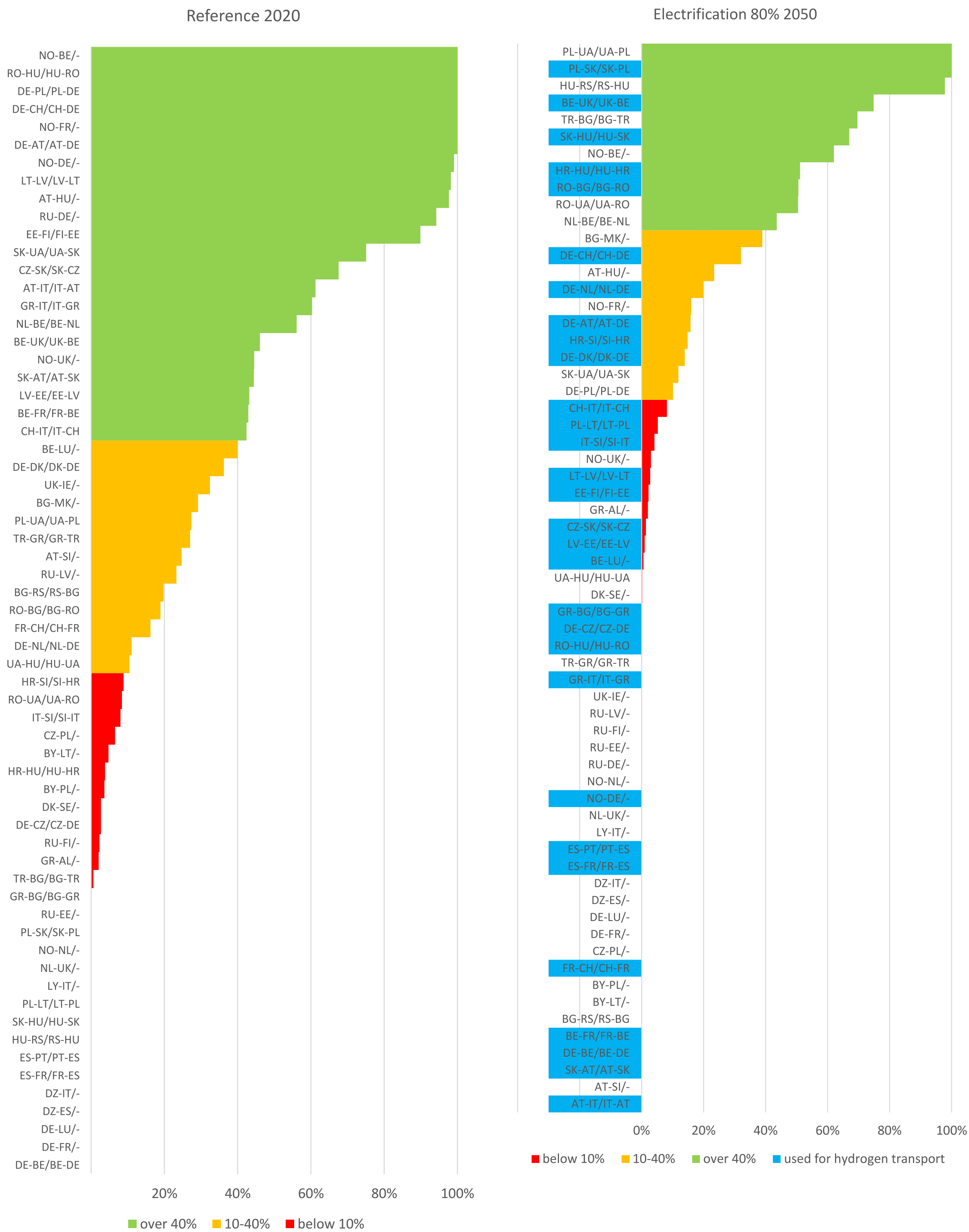

Fig. 8. Utilization of natural gas transport network (flow/capacity %): red bars indicate capacity utilisation below 10%; orange between 10 and 40%; green above 40%; blue colouring shows that the pipeline or one of its string is repurposed for hydrogen. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)
Source: REKK modelling

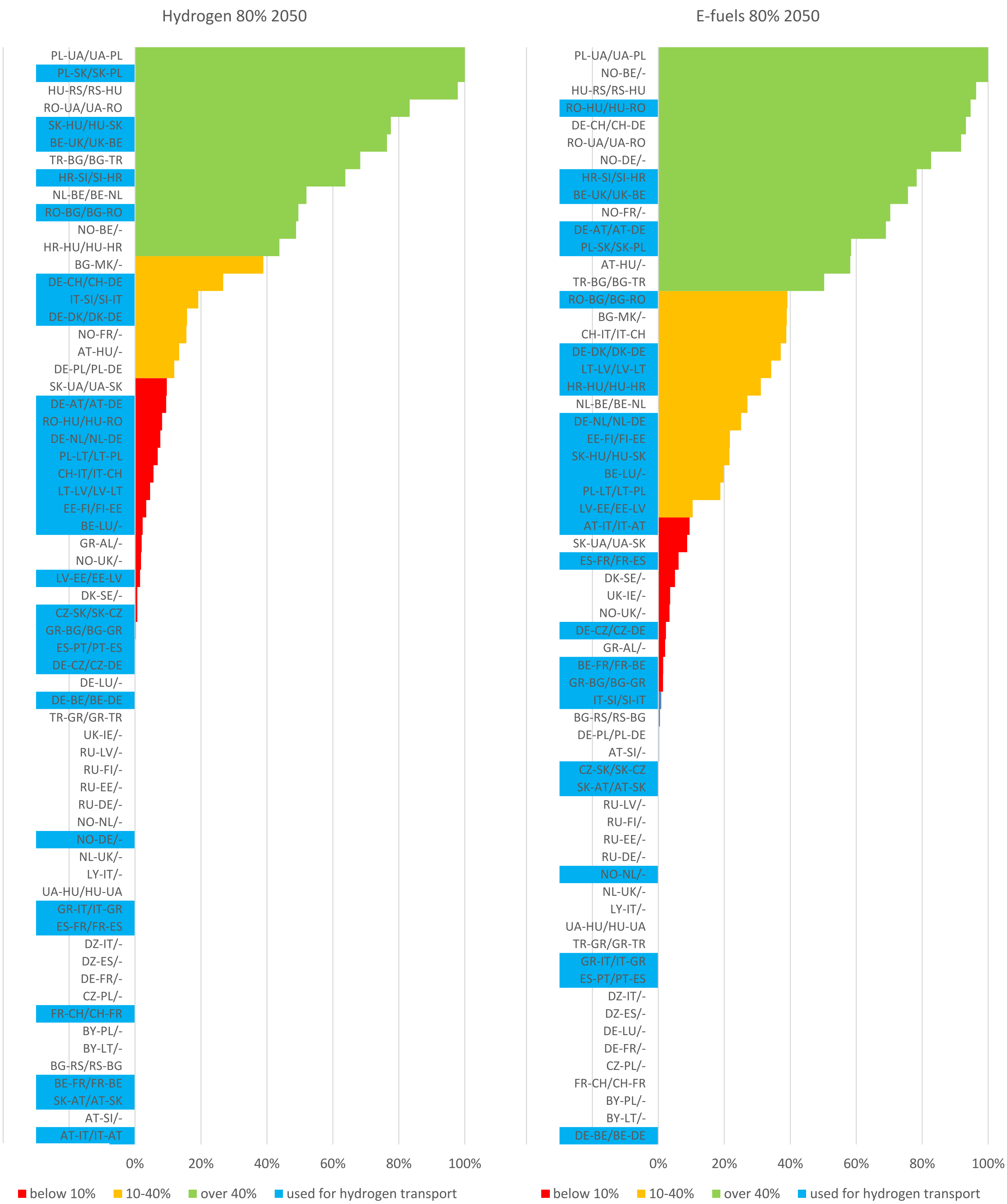

Fig. 8. (*continued*).

Table 10
Utilization indicators for gas transmission pipelines (EU-27+UK + NO + CH).

	A	B	C	B/A	C/A	1-C/A
	pipeline capacity	pipeline capacity with flow (natural gas)	pipeline capacity with flow (natural gas plus repurposed for hydrogen)	capacity utilised (natural gas)	capacity utilised (natural gas and repurposed for hydrogen)	capacity not in use
	TWh/year	TWh/year	TWh/year	%	%	%
REF 2020	15407	10709	10709	70%	70%	30%
Elec_80 (2050)	16635	6049	8746	36%	53%	47%
H2_80 (2050)	16635	6575	9343	40%	56%	44%
E-Fuel_80 (2050)	16635	7182	9239	43%	56%	44%

4.3. *Natural gas infrastructure findings*

The gas network utilization is calculated as the annual gas flow divided by available technical capacity. In Fig. 8 pipelines figures are depicted in decreasing rates of utilization for the given scenarios. Compared to the current situation in REF 2020 on the left-top, the utilization of pipelines drops significantly by 2050 in the 80% technology scenarios. The blue colouring indicates the need for repurposing of one or more cross-border pipeline strings. Despite this repurposing, we observe more unused pipes. Similarly, the use of EU import pipelines declines considerably.

The capacity utilisation was condensed into a single indicator representing the capacity of the used pipelines divided by the capacity of the total network. This means that if a pipeline capacity utilisation is 10%, the full capacity of the required pipeline is considered. Beginning at 70% in 2020, by 2050 the indicator falls to 36% in the Electrification scenario and 40% in the H2-scenarios, while the highest utilization of 43% is achieved in the E-fuel scenario (see B/A column in Table 10). Part of the natural gas pipeline system is repurposed to accommodate hydrogen flows. When the partial repurposing is accounted for, the capacity ratio of the used pipelines rises to 53–56% in all scenarios (see C/A column in Table 10). This implies that the 30% of unused pipeline capacity in 2020 increases to 44–47% by 2050 in the scenarios (see 1-C/A column in Table 10).

5. Conclusions and policy recommendations

Our primary finding is that hydrogen blending with natural gas in natural gas-grids is not a viable long-term solution for hydrogen transport. The necessary natural gas flows that must be present for hydrogen to be blended is a significant constraint that ultimately makes blended hydrogen negligible.

Rather, in the future hydrogen will be transported via repurposed natural gas pipelines or dedicated new hydrogen infrastructure. The total hydrogen network realized by 2050 in the EU-27 varies between 18,000 and 20,000 km depending on the technology scenario; this is some 10% of today's 225,000 km natural gas transmission infrastructure.[4] In fact, according to hydrogen demand and production estimates used in the modelled scenarios, the majority of this future hydrogen network will already need to be in place by 2030, though it would be underutilized until 2050. About 57–65% of the network consists of repurposed gas pipeline in the technology scenarios. This infers that the investments will take place at the beginning of the transition period and is not equally spread over subsequent years.

The investment costs for the hydrogen network is robust across the scenarios, ranging from EUR 19–25 bn over the 2020 to 2050 period.

During the transition, there is a distinct risk of over-investment for flows that might be re-routed later when new competing routes are built in a more integrated network. To mitigate this risk, long-term hydrogen transport contracts might be needed to secure the necessary revenues for the investments. Alternatively, the cheaper repurposed gas pipelines would not require such a long-term guaranteed commitment for investments, only some regulatory flexibility during the transitory period.

Therefore, dedicated EU regulation will be needed for the systematic repurposing and decommissioning of existing gas infrastructure to enable hydrogen transportation. By 2050 there will be no unabated fossil gas transmitted through the EU network with only 33–45% of current (2020) capacities used for natural gas transport compared to 70% today.

Though the modelling did not envisage any new natural gas infrastructure in Europe, the changing geopolitical dynamics caused by the Russian war in Ukraine has brought new LNG projects back into the discussion to compensate for the reduction in Russian gas supplies in the short-term. At the moment, European buyers are struggling with the decision to make long-term offtake commitments from these terminals that risk becoming stranded assets. In order to avoid this, they could be used in the future for importing green LNG or, in the case of floating terminals, relocated to other demand centres outside the EU.

CRediT authorship contribution statement

Peter Kotek: Methodology, Formal analysis, model run, Writing – original draft, Writing – review & editing. **Borbála Takácsné Tóth:** Conceptualization, Methodology, Validation, Writing – original draft, Writing – review & editing. **Adrienn Selei:** Methodology, Formal analysis, Writing – original draft, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgements

This paper was heavily based on the research performed under the grant ENER/C1/2019-481 "Potentials and levels for the electrification of space heating in buildings" by the European Commission, DG Energy.

Annex

[4] ENTSOG TYNDP 2018. https://www.entsog.eu/sites/default/files/2018-12/ENTSOG_TYNDP_2018_Infrastructure%20Report_web.pdf.

Table 11
Estimated hydrogen transport costs, EUR/MWh.

		FROM																														
		AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	RU	SE	SI	SK	UK
TO	AT	–	–	–	–	–	–	1,14	–	–	–	–	–	–	–	–	–	1,30	–	–	–	–	–	–	–	–	–	–	–	–	1,00	–
	BE	–	–	–	–	–	–	0,97	–	–	–	–	1,14	–	–	–	–	–	–	–	–	–	0,47	1,71	–	–	–	–	–	–	–	1,32
	BG	–	–	–	–	–	–	–	–	–	–	–	–	1,02	–	–	–	–	–	–	–	–	–	–	–	–	0,82	–	–	–	–	–
	CH	–	–	–	–	–	–	1,16	–	–	–	–	1,05	–	–	–	–	1,37	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CY	–	–	–	–	–	–	–	–	–	–	–	–	2,56	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CZ	–	–	–	–	–	–	0,92	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,78	–
	DE	1,14	0,97	–	1,16	–	0,92	–	1,33	–	–	–	–	–	–	–	–	–	–	0,81	–	–	0,85	1,98	1,53	–	–	2,88	–	–	–	–
	DK	–	–	–	–	–	–	1,33	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,43	–	–	–
	EE	–	–	–	–	–	–	–	–	–	–	0,43	–	–	–	–	–	–	–	–	0,54	–	–	–	–	–	–	–	–	–	–	–
	ES	–	–	–	–	–	–	–	–	–	–	–	2,04	–	–	–	–	–	–	–	–	–	–	–	–	0,92	–	–	–	–	–	–
	FI	–	–	–	–	–	–	–	–	0,43	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	FR	–	1,14	–	1,05	–	–	1,82	–	–	2,04	–	–	–	–	–	–	–	–	–	–	–	–	2,76	–	–	–	–	–	–	–	–
	GR	–	–	1,02	–	2,56	–	–	–	–	–	–	–	–	–	–	–	2,20	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	HR	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,06	–	–	–	–	–	–	–	–	–	–	–	–	–	0,71	–	–
	HU	0,96	–	–	–	–	–	–	–	–	–	–	–	–	1,06	–	–	–	–	–	–	–	–	–	–	–	1,09	–	–	–	0,41	–
	IE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,96
	IT	1,30	–	–	1,37	–	–	–	–	–	–	–	–	2,20	–	–	–	–	–	–	–	1,89	–	–	–	–	–	–	–	0,98	–	–
	LT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,52	–	–	–	1,11	–	–	–	–	–	–	–
	LU	–	0,34	–	–	–	–	0,81	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	LV	–	–	–	–	–	–	–	–	0,54	–	–	–	–	–	–	–	–	0,52	–	–	–	–	–	–	–	–	–	–	–	–	–
	MT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,89	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	NL	–	0,47	–	–	–	–	0,85	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,33	–	–	–	–	–	–	–	1,28
	NO	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,90	–	–	–
	PL	–	–	–	–	–	0,94	1,53	–	–	–	–	–	–	–	–	–	–	1,11	–	–	–	–	–	–	–	–	–	–	–	0,91	–
	PT	–	–	–	–	–	–	–	–	–	0,92	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	RO	–	–	0,82	–	–	–	–	–	–	–	–	–	–	–	1,09	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	RU	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	SE	–	–	–	–	–	–	–	1,43	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	SI	0,41	–	–	–	–	–	–	–	–	–	–	–	–	0,71	–	–	0,98	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	SK	1,00	–	–	–	–	0,78	–	–	–	–	–	–	–	–	0,41	–	–	–	–	–	–	–	–	0,91	–	–	–	–	–	–	–
	UK	–	1,32	–	–	–	–	–	–	–	–	–	–	–	–	–	0,96	–	–	–	–	–	1,28	1,22	–	–	–	–	–	–	–	–

Table 12
Estimated natural gas transport costs assumed, EUR/MWh.

	FROM																																										
	AL	AM	AT	AZ	BA	BE	BG	BY	CH	CZ	DE	DK	DZ	EE	ES	FI	FR	GE	GR	HR	HU	IE	IR	IT	LT	LU	LV	LY	MD	MK	NL	NO	PL	PT	RO	RS	RU	SE	SI	SK	TR	UA	UK
TO AL	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,42	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
AM	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,00	–	–	–	–	1,00	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
AT	–	–	–	–	–	–	–	–	–	–	0,85	–	–	–	–	–	–	–	–	–	–	–	–	1,71	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,98	–	–	–
AZ	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,50	–	–	–	–	–	–
BA	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2,83	–	–	–	–	–	–	–
BE	–	–	–	–	–	–	–	–	–	–	0,82	–	–	–	–	–	0,32	–	–	–	–	–	–	–	–	–	–	–	–	–	0,55	0,14	–	–	–	–	–	–	–	–	–	–	0,44
BG	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,48	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,03	3,41	–	–	–	–	1,52	–	–
BY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,50	–	–	–	–	–	–
CH	–	–	–	–	–	–	–	–	–	–	1,07	–	–	–	–	–	2,06	–	–	–	–	–	–	1,96	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
CZ	–	–	–	–	–	–	–	–	–	–	0,81	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,81	–	–	–
DE	–	–	1,26	–	–	0,86	–	–	1,07	0,98	–	1,72	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,01	0,68	1,25	–	–	–	0,60	–	–	–	–	–	–
DK	–	–	–	–	–	–	–	–	–	–	1,25	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
DZ	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–	–	–	–	0,62	–	–	–	–	–	–
ES	–	–	–	–	–	–	–	–	–	–	–	–	0,56	–	–	–	3,08	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,65	–	–	–	–	–	–	–	–	–
FI	–	–	–	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,62	–	–	–	–	–	–
FR	–	–	–	–	–	0,58	–	–	0,85	–	1,13	–	–	–	1,49	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,45	–	–	–	–	–	–	–	–	–	–	–
GE	–	–	–	1,00	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,50	–	–	–	–	–	–
GR	–	–	–	–	–	–	1,80	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2,85	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,37	–	–
HR	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,74	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,58	–	–	–	–
HU	–	–	0,62	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,19	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,70	3,08	–	–	–	1,23	–	1,60	–
IE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,97
IR	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
IT	–	–	1,37	–	–	–	–	–	0,98	–	–	–	1,43	–	–	–	–	–	1,85	–	–	–	–	–	–	–	–	1,31	–	–	–	–	–	–	–	–	–	–	1,09	–	–	–	–
LT	–	–	–	–	–	–	–	1,12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,23	–	–	–	–	–	1,27	–	–	–	–	–	–	–	–	–	–
LU	–	–	–	–	–	0,00	–	–	–	–	0,70	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
LV	–	–	–	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–	–	–	–	–	1,38	–	–	–	–	–	–	–	–	–	–	–	0,62	–	–	–	–	–	–
LY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
MD	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,74	–
MK	–	–	–	–	–	–	0,97	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NL	–	–	–	–	–	0,49	–	–	–	–	0,92	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,32	–	–	–	–	–	–	–	–	–	–	–
NO	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PL	–	–	–	–	–	–	–	1,68	–	1,99	1,77	–	–	–	–	–	–	–	–	–	–	–	–	–	1,94	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2,00	–	2,35	–
PT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,46	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
RO	–	–	–	–	–	–	0,74	–	–	–	–	–	–	–	–	–	–	–	–	–	0,43	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,14	–
RS	–	–	–	–	–	–	2,28	–	–	–	–	–	–	–	–	–	–	–	–	–	1,39	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
RU	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SE	–	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SI	–	–	0,86	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0,92	–	–	–	1,65	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SK	–	–	0,69	–	–	–	–	–	–	1,01	–	–	–	–	–	–	–	–	–	–	0,91	–	–	–	–	–	–	–	–	–	–	–	1,14	–	–	–	–	–	–	–	–	1,99	–
TR	–	–	–	–	–	–	0,75	–	–	–	–	–	–	–	–	–	–	0,50	0,92	–	–	–	0,50	–	–	–	–	–	–	–	–	–	–	–	–	–	0,00	–	–	–	–	–	–
UA	–	–	–	–	–	–	–	2,58	–	–	–	–	–	–	–	–	–	–	–	–	1,01	–	–	–	–	–	–	–	–	–	–	–	1,24	–	0,88	–	2,08	–	–	1,59	–	–	–
UK	–	–	–	–	–	0,44	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3,00	1,51	–	–	–	–	–	–	–	–	–	–	–

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