CESEC's region potential for renewable and low-carbon gas deployment in the context of infrastructure development

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Contact: Tomasz Bąk
Zita Csoka

E-mail:
Tomasz.BAK@ec.europa.eu
Zita.CSOKA@ec.europa.eu

European Commission
B-1049 Brussels

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Authors

Ioannis Stefanou (Grant Thornton)
Dr. Despina Tzoulaki (Grant Thornton)
John Dimitropoulos (Grant Thornton)
Maria Alexandra Aslanoglou (Grant Thornton)
Agis Koumentakos (Grant Thornton)
Ernesto Zagklis-Tyraskis (Grant Thornton)
Jiří Dvořák (Grant Thornton)
Nicola Gallo (MAI Group)

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Executive Summary

Background and objectives

In order to meet the European Green Deal and REPowerEU objectives, the CESEC region needs to step up the efforts for renewable energy deployment, including renewable and low-carbon gases. In order to do so, an adequate network of infrastructure, alongside a fit-for-purpose regulatory framework, needs to be developed. In this context, DG ENER has commissioned a study to Grant Thornton in association with AF Mercados EMI *(ENER/C4/2021-444 | CESEC's region potential for renewable and low-carbon gas deployment in the context of infrastructure development)* aiming at exploring the potential for the production and deployment of renewable and low-carbon gases (renewable hydrogen and biomethane specifically), as well as their integration in the CESEC region.

In accordance with the increasing importance of hydrogen and biomethane in Europe, the 2013 TEN-E Regulation (REGULATION (EU) No 347/2013) has been revised to introduce new infrastructure categories and end policy and financial support to cross-border natural gas infrastructure. The new infrastructure categories include electrolysers, hydrogen transport, storage facilities, and receiving terminals, as well as smart gas grids for integrating renewable and low-carbon gases (such as biomethane and renewable hydrogen) into the existing networks. In addition, for the first time, Projects of Mutual Interest (PMI) are also introduced in the revised TEN-E Regulation (Regulation (EU) 2022/869). The 1st PCI/PMI list under the revised TEN-E Regulation was published in November 2023 and came into force in May 2024. Moreover, the Council and the Parliament reached a provisional political agreement[1] on a regulation that establishes common internal market rules for renewable and natural gases and hydrogen. The Energy Community countries also adopted and adapted the revised TEN-E Regulation with Ministerial Council Decisions 2023/02/MC-EnC and 2023/03/MC-EnC in December 2023. Upon its entry into force, it will repeal the old regulation on 31 December 2024[2].

Methodological Approach

The study commences with a presentation of the most significant advancements in the EU policy environment concerning renewable and low-carbon gases. Onwards, the analysis focuses on the assessment of the production and consumption patterns of renewable hydrogen and biomethane in the CESEC region. In addition, the levelised costs of renewable hydrogen and biomethane production (LCOH and LCOB, respectively) are estimated, including an estimation on how those are expected to differentiate from one country to another and also across the years in the 2030-2050 timeframe. It is noted that despite the fact that simulations have been conducted until 2050, they are presented only until 2045 in Chapter 3, due to the fact that the timeframe of 2050 entails large uncertainty.

With regards to infrastructure, an assessment of its readiness to accommodate renewable hydrogen and biomethane in the region is conducted with a focus on its current status (i.e., transmission and distribution networks and storage sites). The activities and plans of the Operators regarding testing of their existing infrastructure, construction of new and repurposing of actual infrastructure are also presented. To this end, a high-level overview of the national investment plans on TSO- and, to the extent possible, on DSO- level, concerning renewable hydrogen and biomethane deployment is provided. The analysis focuses on the main infrastructure bottlenecks, and the infrastructure adaptation needs for pure hydrogen transportation, reception and storage. Finally, findings from interaction with key stakeholders coupled with the modelling analysis highlight the potential hydrogen flows to be facilitated by hydrogen pipelines. This is a response to meeting the hydrogen demand in the region.

The approach followed for the implementation of the study relies on a combination of tools, such as analysis of publicly available data, studies and policy documents, elaboration of a full-fledged survey, initiation of complementary interviews with key stakeholders, organization of a stakeholders' workshop and the conduct

[1] Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal markets for renewable and natural gases and for hydrogen (recast) - pdf (europa.eu)
[2] Implementing the new TEN-E Regulation - Energy Community Homepage (energy-community.org)

of a regional modelling analysis. More specifically, desktop research is conducted to source the latest available data on production and consumption of renewable hydrogen and biomethane, the relevant targets set by each of the countries in the CESEC region, the planned production plants and infrastructure, as well as the infrastructure costs and the production cost drivers. In this context, the National Energy and Climate Plans (NECP) of the CESEC countries, as well as the National Hydrogen Strategies (NHS) - wherever available -, the Union-wide Ten-Year Network Development Plan (TYNDP), the Network Development Plans (NDP) of the Transmission System Operators (TSO) and of the Distribution System Operators (DSO), the 1st PCI/PMI list, the Hydrogen Project Visualisation Platform of ENTSOG, and the Hydrogen Infrastructure Map have been assessed. Moreover, an online survey based on questionnaires that differentiate depending on the type of key stakeholder (i.e., TSO, DSO, National Regulatory Agencies (NRAs), etc.) was launched. Finally, interviews with targeted stakeholders have been conducted to facilitate the information flow, as well as when clarifications on the responses in the survey are needed. In order to assess the potential future cross-border flows of renewable hydrogen between EU Member States and Energy Community Contracting Parties, a modelling exercise is implemented utilising PLEXOS software.

Current production and demand patterns

The first step of the analysis regards the assessment of the production and consumption patterns of renewable hydrogen and biomethane in the CESEC region, as well as the prevailing policy and regulatory environment. Overall, the CESEC region exhibits a large heterogeneity in the developments pertinent to the renewable and low-carbon gases in various aspects. As of 2024, production of hydrogen was mostly limited to captive fossil-based hydrogen (produced via reforming) for large hydrogen consumers and particularly refineries, steel, and cement industries. In the CESEC region, only Italy produced fossil-based hydrogen with abatement as a result of combining carbon capture with the reforming process, with a production of slightly below 25 TWh annually, followed by Greece with approx. 13 TWh and Hungary about 7.5 TWh annually. Albania, Serbia and Ukraine also produced fossil-based hydrogen; however, no specific data are publicly available. On the other hand, countries like Moldova, Kosovo, Bosnia and Herzegovina, North Macedonia and Montenegro neither produce, nor consume hydrogen till present. By 2023, very limited production of renewable hydrogen took place in Austria, Slovenia, Hungary and Greece, as a result of small-scale projects (below 2 MW electrolysers) that are either operational or at demonstration phase. Several hydrogen production projects are in development stage, which will supply approx. 30.9 TWh renewable hydrogen by 2030, should they materialise. Yet, announced projects are concentrated in very few countries only, i.e., Greece, Italy, Austria, Romania, Slovenia, and Hungary. In terms of policy formulation, Italy, Austria, Greece, Hungary, and Croatia have set targets of installed electrolyser capacity by 2030 (i.e., 5 GW, 1 GW, 300 MW, 240 MW and from 70 to 1,273 MW, respectively) according to their published strategic documents (i.e., draft updated NECPs, final NECPs, NHS).

With regards to biomethane, to date, very few countries (i.e., Italy, Austria, Hungary, Ukraine) produce biomethane and only Italy and Hungary operate large-scale biomethane plants (i.e., >1000 m3/h). Several countries (i.e., Bulgaria, Croatia, Greece, Romania and Slovenia) report biogas production, which is a precursor of biomethane, as a result of existing financial incentives provided to biogas for power generation.

Hydrogen and biomethane potential & production costs

CESEC countries possess excellent energy potential, such as biomass and organic waste, solar irradiance, and onshore and offshore wind. Previous analysis in the CESEC region[3] had estimated a potential of 1,180 GW of PV, 890 GW onshore wind potential and 62 GW of offshore wind. The study had estimated that the current cost-competitive potential for renewable electricity generation in South-East Europe is approx.

[3]https://op.europa.eu/en/publication-detail/-/publication/434fb711-a5a4-11ec-83e1-01aa75ed71a1/language-en

130 GW. Whereas only a portion of that reported technical potentials can be exploited cost-effectively until 2030, resource availability is not a limiting parameter for accelerating the deployment of renewable technologies and subsequently renewable and low-carbon gases within the region. The remaining techno-economic potential for renewable hydrogen in 2030 in the region, after the coverage of electricity supply needs[4], is approx. 2,600 TWh. The largest theoretical potential is found in Ukraine (approx. 700 TWh), Italy (520 TWh), Romania (430 TWh).

As in all areas in Europe, the levelised cost of renewable hydrogen (LCOH) is highly dependent on capital costs (particularly of the electrolyser) and the cost of renewable electricity. The latter cost driver is strongly affected by the RES mix and the capacity factor for each technology, which is slightly improving over time. The study estimates the LCOH [5] as produced in each of the CESEC countries by an electrolyser of 100 MW installed capacity assuming that the needs in electricity are met exclusively by solar PV. The estimates, considering the EU countries in the CESEC region only, range from 3.6 to 5.5 EUR/kg. Those are reasonable if compared with the reported median by Hydrogen Europe[6] (3.0 to 5.0 EUR/kg) in the EU countries (including UK and Norway).

The CESEC region also has a considerable biomethane techno-economic potential. The sustainable biomethane potential is calculated in each of the countries in the CESEC region following the Gas for Climate[7] methodology. The outcome of exercise highlights that Ukraine exhibits by far the largest potential in the region (approx. 20 TWh in 2030), followed by Italy (approx. 15 TWh), Romania (approx. 9 TWh) and Hungary (approx. 6,5 TWh).

With regards to biomethane production costs, the main cost drivers for the levelised cost of biomethane (LCOB) are the cost of the biodigesters, the feedstock cost and the cost of the upgrade and injection unit. The calculated LCOB ranges between 52 and 82 EUR/MWh, depending primarily on the availability of feedstock type and the plant size. It is noted that only in the case of agricultural residues, roadside feedstock costs[8] arise and are added to the transportation cost incurring from the feedstock source to the process plant.

Infrastructure projects promoted in the CESEC region

The uptake of renewable and low-carbon gases will require the deployment of large-scale cross-border and national transmission projects. Overall, there is a large number of infrastructure[9] projects (i.e., projects related to transmission, distribution and storage) planned in the CESEC region. They are included in the national NDPs of the TSOs and the DSOs, the Union-wide TYNDP of ENTSOG [10], as well as reported by other publicly available sources, including the Hydrogen Infrastructure Map[11]. An exhaustive overview performed illustrates that Italy, Austria, Hungary, Romania and Greece have planned the highest number of infrastructure projects aimed at integrating hydrogen and/or biomethane in the region. Similarly, the majority of the projects concern renewable and low-carbon hydrogen and are located in Hungary, Romania and Italy. On the contrary, the biomethane infrastructure projects that are promoted are significantly fewer and located in Italy. Broadly, the majority of the promoted projects concern the transmission network alone. Part of the hydrogen infrastructure projects promoted in the region have been included in the 1st PCI/PMI list[12] which was

[4] For power generation, heat and cooling and transport
[5] the calculated LCOH only covers hydrogen production costs, i.e., does not include additional costs of hydrogen compression (or liquefaction) and transportation.
[6] https://hydrogeneurope.eu/clean-hydrogen-monitor-2022/
[7] https://gasforclimate2050.eu/wp-content/uploads/2023/12/GfC_MarketStateTrends_2023.pdf
[8] Roadside feedstock costs are costs of biomass production, collection and pre-treatment, up to the road where the biomass feedstock is located. However, manure (liquid and solid) cost has been assume to be null. Most of the time, farmers give manure for free to the conversion plant in exchange of digestate used by the farmer as fertilizer.
[9] Infrastructure projects are considered to include as per TEN-E the following project categories: pipelines for transporting hydrogen, including the use of repurposed natural gas infrastructure, facilities for storing hydrogen, facilities for receiving, storing, and regasifying liquefied hydrogen or hydrogen carriers, equipment and installations for safely and efficiently operating a hydrogen system, equipment for the transport sector that utilises hydrogen or hydrogen-derived fuels, smart gas grids that allow for the integration of renewable gases. Smart grids projects are broadly included under either transmission or distribution.
[10] ENTSOG exceptionally published an updated TYNDP list of projects in October 2022 in response to the goals set in the EC's REPowerEU Plan and its associated initiatives to accelerate the integration of renewable gases
[11] H2 Infrastructure Map Europe (h2inframap.eu)

published in November 2023 and came into force in May 2024. More specifically, the list features the Hydrogen corridor Italy – Austria – Germany (includes the Hydrogen Readiness of the TAG pipeline, the Hydrogen Backbone WAG and Penta West, and the Italian Hydrogen Backbone), the Hydrogen interconnector between Greece and Bulgaria (includes internal infrastructure in both countries), and the Generic Corridor aiming to transmit hydrogen from Ukraine to Slovakia, Czechia, Austria, and Germany.

Infrastructure readiness

In general, there is currently a lack of infrastructure capable of accepting pure hydrogen in the CESEC region. TSOs and Storage Operators in several countries of the region have started conducting evaluations on their infrastructure components through laboratory testing to assess the infrastructure compatibility for hydrogen blends, as well as for pure hydrogen. However, the degree of progress varies significantly between the countries examined. Out of the CESEC countries, Italy, Austria and Hungary are more advanced with regards to the assessment of the compatibility of their networks.

Italy has possibly undertaken the most steps towards hydrogen readiness. Around 70% of SNAM's natural gas pipelines are compatible with pure hydrogen, with efforts being undertaken to increase this percentage to 100% of the network. SNAM indicates that reaching 5-10% hydrogen blends requires only minimal investments, mostly installation of gas chromatographs and other minor instruments replacements. In **Austria**, the ability of the transmission system to accommodate hydrogen blends up to 10% has been verified by technical assessments concluded by TAGG. This also requires only minor investments. Furthermore, the existing pipelines are compatible for pure hydrogen. The transmission system operated by Gas Connect Austria, the other country's operator, is reported to be able to accommodate hydrogen blends up to 4%[13]. In view of **Slovenia's** aim (NECP) to incorporate a 10% hydrogen share into the transmission and distribution network by 2030, Plinovodi is carrying out tests (pilot project at preliminary stage) and has set a target of 5% blending by 2025. In **Romania**, the gas TSO TRANSGAZ is carrying out tests with hydrogen blends and investigates the modifications required in the transmission network to make this possible. DESFA, the gas TSO of **Greece**, has finalised an initial assessment of its existing infrastructure for the injection of hydrogen blends showing that 5 % hydrogen blends into existing infrastructure for natural gas could be realised with minor modifications only. In **Hungary**, the gas TSO FGSZ declares a 2% hydrogen readiness of their system.

Austria, Italy, and Hungary are the only countries in the CESEC region that have advanced towards the integration of biomethane into their national system as not only do they produce biomethane but also directly inject quantities of it into the existing gas transmission and distribution systems. The injection of biomethane in Austria takes place exclusively at the distribution level. On the other hand, available information indicates that both the transmission and distribution networks in Italy and Hungary receive injections of biomethane. There are only high reported quantities of biomethane produced and injected into the Hungarian national gas grid. For the rest of the countries, there is neither biomethane injection, nor R&D or pilot projects focused on biomethane and none of the existing biogas plants have been upgraded for production of biomethane.

Regional Infrastructure Development Modelling for hydrogen

Having assessed demand for renewable gases, as well as the potential for RES (and their costs) to be used in the production of renewable hydrogen to meet that demand across the CESEC countries, the likely least costly deployment of infrastructure by 2050 is modelled, aiming to yield valuable insights for policymakers. Two major scenarios are elaborated in the context of the modelling analysis for the time horizons of 2030 and 2050:

- **Scenario A – CESEC Regional**, focusing exclusively on the CESEC countries (internally interconnected with each other as applicable, using existing power and gas interconnections but

[12] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=PI_COM:C(2023)7930
[13] Gas Connect Austria (2023). Personal communication, 07 March

isolated (in hydrogen terms) from the rest of Europe without considering any imports or exports from the region.

- **Scenario B – CESEC + Germany / North Africa**, taking into consideration the increased hydrogen demand in Germany, as well as the prospect of large amounts of hydrogen produced in North Africa and supplied to Italy via undersea pipelines and further to the region.

The analytical framework for conducted quantitative assessment utilises a large array of assumptions regarding fuel sourcing, generation mix, transmission infrastructure, as well as planned infrastructure projects in each country. Most of these assumptions have been derived from national policy and strategic documents (such as NECPs, NHSs, TYNDPs, etc.). In the absence of formal hydrogen targets data/forecasts for some of the countries in the CESEC region, assumptions have been provided by stakeholders in the conducted interviews, namely European Commission (EC) and gas TSOs. Regarding the power generation mix, the model considers the data from Reference Scenario 2020 fuel mix evolution, as publicly available from EC. In the taken approach, hydrogen demand after 2030 is assumed to be supplied exclusively through electrolysers supplied by RES. Moreover, hydrogen is assumed to substitute non-power gas demand in industry and transport. Finally, it has been assumed that hydrogen will not be made available for power generation purposes, as this is deemed uneconomical and energy intensive.

In terms of the hydrogen transmission network planning, the model encompasses the development of cross-border hydrogen transportation capacity through conventional steel high-pressure pipeline networks. Using the published Union-wide TYNDP of ENTSOG, a list of proposed projects for dedicated hydrogen pipelines is incorporated, assuming predefined capacities. The model is allowed to determine when, where, and to what extent these pipelines would be constructed. Also, the model is set free to build incremental hydrogen transmission capacities where needed after 2034, to meet cross-border demand/supply imbalances and minimise total system costs for the period to 2050.

Until 2030 the policy targets set by CESEC countries as stated in their NECPs and as submitted in the context of the PCI/PMI projects, indicate that demand will primarily be covered by domestic supply. Onwards, and until 2050 capital-intensive cross-border dedicated hydrogen pipelines will have to be developed, potentially in combination with repurposing of existing assets.

Prominent findings of the modelling analysis include:

- As a general remark, modelling analysis conducted through PLEXOS aligns with the results of the PCI/PMI process with regards to future cross-border flows and the need for respective transmission infrastructures.
- In the Scenario A – CESEC Regional in 2030, local hydrogen demand does not appear to be sufficient to justify the development cross-border transportation corridors either through Tunisia/Italy or from Greece toward Central-Eastern Europe. However, the comparison of scenarios A and B clearly indicates that demand in Germany is a catalyst for large scale cross- border infrastructures and that eventual hydrogen needs of Germany will partly determine the sizing of the proposed infrastructures in the CESEC region.
- Eventually three corridors emerge with high degree of certainty, i.e., imports from Algeria and Tunisia to Italy and onwards to Germany, a hydrogen corridor initiating from Greece through the Balkan region (Bulgaria, Romania) and further north to Germany and a corridor originating from Ukraine to Germany through Slovakia and Czech Republic, as well as Slovakia and Austria.
- It would be also very plausible to assume that in the hydrogen corridor that will originate from Greece to Bulgaria, Romania and northern, other Energy Community Contracting Parties such as Serbia, North Macedonia, Bosnia and Herzegovina may connect to that corridor, assuming repurposing of existing assets and potentially also transforming projects that were originally designed for natural gas but are hydrogen-ready.

- The supply routes to meet high demand in Italy and Germany largely depend on assumptions regarding its cost at the entry point in South Italy from Tunisia (and other non-techno-economic aspects such as political stability in Ukraine). In this context, it appears highly plausible to deploy large RES and electrolyser installations in North Africa, where greater RES capacity factors are assumed to produce renewable hydrogen in order to meet demand in the CESEC region.
- In the case of commercial arrangements between industrial consumers in Germany and developers of renewable hydrogen projects in North Africa, a much larger part of German demand will be supplied from Africa through the SoutH2 Corridor via Italy and Austria (i.e. German imports from the CESEC region will constitute a higher percentage compared to the 40% of the total imports currently assumed) and the flows from North Africa to Germany will be even higher.
- Overall, across the two scenarios, it is observed that there is a huge potential for further expanding the RES build-out in the CESEC region. As the countries move away from fossil fuels, they have the prospect of collectively planning RES generation and hydrogen production capacity development, as well as the development of corresponding transmission networks. Given that the timeframe of the analysis extends well beyond the ten-year period of the TSO network development plans, there is a need for a greater number of projects to accommodate hydrogen flows that are either immature or not even on planning stage yet.
- In order to satisfy the overall hydrogen needs, considerable electrolyser capacity is required to be developed in the CESEC region, amounting to approx. 75 GW in Scenario A and 62 GW in Scenario B until 2045. Under Scenario B, significantly less RES generation capacity is required for electrolyser needs, underlining the impact of the hydrogen transported from North Africa at lower costs, which is able to cover part of CESEC's demand. Thus, CESEC countries follow a more moderate approach on the development of electrolyser installations on their ground.
- Considering the NECP targets for 2030 and the data communicated during the PCI/PMI process needs, it is estimated that renewable hydrogen in the CESEC region (excluding consumption in Germany) can displace approx. annually 54 TWh of natural gas in industry and diesel (for the transport sector) in 2030 and approx. 411 TWh in 2050, assuming that all hydrogen produced is renewable.

Policy, market and regulatory context

From a policy, regulatory and market perspective, in the course of the study, various challenges have been identified by stakeholders relevant to the uptake of renewable and low-carbon gases.

Key issues that have been identified include the following:

- The **regulatory framework** for hydrogen at EU level will soon be in place, i.e. the EU Hydrogen and Decarbonised Gas Market Package, and transposed into national legislation initially of Member States and subsequently of Energy Community Contracting Parties. In view of the anticipated challenges relating to the transposition, active support from CESEC High-Level Group is likely to be needed. It is therefore anticipated that the absence of a clear regulatory framework which creates uncertainty for investors, will soon be remediated and that CESEC countries will gradually proceed to the implementation of the relevant primary and secondary framework. To this end, useful lessons can be drawn from countries of Central and Northern Europe with regards to the effectiveness of the implemented regulatory frameworks.
- Existence of limited submissions only of draft updated **NECPs and developed policy documents and strategies** (such as National Hydrogen and Biomethane Strategies) that foster the integration of renewable and low-carbon gases. Moreover, while most EU countries in the region include clear policies and provisions for these gases in their NECPs, in some cases, targets, forecasts and implementing actions are missing or need to be further elaborated.

- **Demand for hydrogen end-uses per sector** in the vast majority of cases is either not clearly mapped in the entire CESEC region or there is an inherent uncertainty with regards to its buildup, thus impeding forward looking infrastructure planning. Moreover, it becomes even more challenging projecting the demand beyond the horizon of 2030.
- The **costs for the production of renewable hydrogen and biomethane** are still higher compared to the fossil fuels that they are going to substitute or the traditional means of their production (such as reforming) and, thus, not yet competitive without support schemes. The gradual decrease of production costs (for instance electrolysers, renewables) as a result of technological improvement in combination with increasing ETS prices and targeted support schemes are key drivers for creating a renewable hydrogen market.
- The **decentralised biomethane production patterns** create challenges for accommodating scattered volumes into limited injection points. Moreover, difficulties in the supply chain related to ensuring stable and sufficient feedstock streams for large-scale plants impede the development of economies of scale.

Infrastructure development

The development of dedicated infrastructure or the refurbishment of existing infrastructure for the transportation of renewable and low-carbon gases face a number of challenges:

- **Injection and transportation of pure hydrogen** is not possible at the moment in any of the CESEC countries. Hydrogen blends are possible to a certain extent in some countries, yet bearing challenges, i.e., potential need for deblending, varying standards, different energy contents, instability of the blend, etc. Moreover, there is absence of reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances.
- **Hydrogen blending could only represent a temporary solution**, which comes at a cost, could result in lock-ins, stranded assets and overall is not promoted by EU policy and legislation.
- The **industry's limited experience with pipelines designed for 100% hydrogen** transport poses challenges and uncertainties such as embrittlement, which can compromise system safety and reliability of infrastructures. In addition, many aspects of hydrogen integration, including material degradation and equipment stack durability, are still largely unexplored, contributing to the overall uncertainty.
- Progress has been achieved in several countries with regards to either **assessing or constructing hydrogen-ready pipelines** which appear to be the most cost-effective transportation mode for medium- to long-distances transportation, i.e., above 100 kilometres. Nevertheless, further technical and economic assessment needs to be made with regards to the hydrogen readiness of infrastructure and the prospects of either refurbishment of existing LNG terminals and the design of hydrogen or hydrogen carrier terminals (e.g., ammonia/methanol), with the latter being the most realistic option, yet still very expensive.
- With regards to biomethane, **reverse flow possibility from the distribution network to the transmission system** will become increasingly important upon increasing injected biomethane quantities that will potentially surpass the demand at the distribution level. Therefore, the installation of reverse flow facilities, prioritising gas grid injection for biomethane and increasing cooperation between transmission/distribution adjacent gas grid Operators is crucial, should be studied and prioritised by TSO/DSOs.
- **Excessive oxygen concentrations** in biomethane can cause issues like corrosion, bacterial growth, and sulphur build-up and, thus, limits on the oxygen acceptance levels exist at country level. Those are, however, diverse and in some cases very low, especially compared to typical levels of oxygen at the outlet of the biomethane production plant. Thus, countries with strict

oxygen acceptance levels might need to modify their gas quality standards towards more reasonable levels. This is important especially on the transmission and storage side in order to harmonise the quality standards across the overall region and facilitate cross-border trade.

Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
AERS	Energy Agency of the Republic of Serbia
AFIR	Alternative Fuels Infrastructure Regulation
AGEN RS	Slovenian Regulatory Authority
AEL	Alkaline Electrolyser
ANRE	Romanian Energy Regulatory Authority
ARERA	Italian Regulatory Authority for Energy, Networks and the Environment
ASME	American Society of Mechanical Engineers
BERG	Berg System Gaz (Romania)
BRUA	Bulgaria-Romania-Hungary-Austria Natural Gas corridor
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CCS	Carbon Capture & Storage
CEF	Connecting Europe Facility
CEN/CENELEC	European Standardisation Committees
CERA	Cyprus Energy Regulatory Authority
CESEC	Central and South-Eastern Europe Energy Connectivity
CFD	Contract for Differences
CGH2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO2e	Carbon Dioxide Equivalent
DESFA	Hellenic TSO
DG-ENER	Directorate General for Energy
DSO	Distribution System Operator
DVGW	German Technical and Technical Association for Gas and Water
bulgDZP	Natural Gas Distribution Association
EBA	European Biogas Association
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EEU	European Environment Agency
EHB	European Hydrogen Backbone
ENTSOE	European Network of Transmission System Operators for Electricity

ENTSOG	European Network of Transmission System Operators for Gas
ERC	Energy and Water Services Regulatory Commission of the Republic of North Macedonia
ERE	Albanian Energy Regulatory Authority
ERGaR	European Renewable Gas Registry
ERP	Economic Reform Programme
ETS	Emissions Trading System
EU	European Union
EWABA	European Waste-based & Advanced Biofuels Association
EWRC	Energy & Water Regulatory Commission
FAOSTAT	Food and Agriculture Statistics Organization
FCEV	Fuel-Cell Electric Vehicles
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FEED	Front End Engineering Design
FERK	Regulatory Authority for Energy of Bosnia and Herzegovina
FGSZ	Gas Transmission System Operator of Hungary
FSRU	Floating Storage Regasification Unit
GCA	Gas Connect Austria
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GEODE	DSO Association
GHG	Greenhouse Gas Emissions
GIE	Gas Infrastructure Europe
GIS	Geographic Information System
GO	Guarantee of Origin
GRTGAS	French natural gas TSO
GT	Grant Thornton
GW	Gigawatt
GWh	Gigawatt Hour
H2I	Hydrogen Initiative
HDV	Heavy-Duty vehicles
HERA	Croatian energy regulatory agency
HFC	Hydrogen Fuel Cell
HLG	High Level Group
HRS	Hydrogen Refuelling Station
HyLaw	Hydrogen Law

IBS	Interconnector Bulgaria Serbia
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IFI	International Financial Institution
IGB	Interconnector Greece Bulgaria
IGU	International Gas Union
IOGP	International Association of Oil & Gas Producers
IPCEI	Important Projects of Common European Interest
IRENA	International Renewable Energy Agency
JKP	Slovenian Public Utility Company
JRC	Joint Research Centre
LCOB	Levelised Cost of Biomethane
LCOE	Levelised cost of electricity/energy
LCOH	Levelised Cost of Hydrogen
LH2	Liquid Hydrogen
LNG	Liquified natural gas
LOHC	Liquid Organic Hydrogen Carriers
LPG	Liquified Petroleum Gas
MAVIR	Hungarian TSO
MEKH	Hungarian Energy and Public Utility Regulatory Authority
MEP	Members of the European Parliament
NCCS	National Climate Change Strategy
NCEP	National Centres for Environmental Prediction
NECP	National and Energy Climate Plans
NERC	North American Electric Reliability Corporation
NEURC	National Energy and Utilities Regulatory Commission
NPV	Net Present Value
NRA	National Regulatory Authority
NREL	National Renewable Energy Laboratory
NRRP	National Recovery and Resilience Plan
OPEX	Operating Expenditures
OST	Albanian TSO
RAE	Greek Regulatory Authority for Energy
PCI	Project of Common Interest
PEM	Proton Exchange Membrane Electrolyser

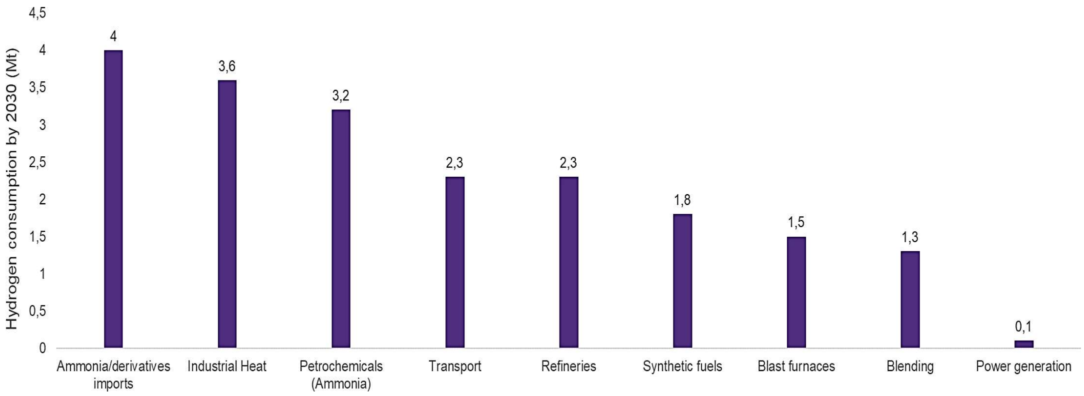
PLEXOS	Energy Modelling Software
PLINACRO	Croatian TSO
PLINOVODI	Slovenian TSO
PPP	Private Public Partnership
PRCI	Pipeline Research Council International
PRIMES	E3 Modelling Software
PSA	Pressure Swing Adsorption
PV	Photovoltaics
RAB	Regulated Asset Base
RAE	Regulatory Energy Authority of Greece
RCF	Renewable-carbon Fuels
RED	Renewable Energy Directive
REGAGEN	Energy and Water Regulatory Agency of Montenegro
RES	Renewable Energy Source
RFNBO	Renewable Fuels of Non-Biological Origin
RRF	Recovery and Resilience Fund
RRP	Recovery and Resilience Plan
SCADA	Supervisory Control and Data Acquisition and Gas Management System
SMR	Steam Methane Reforming
SNAM	Italian TSO
SouTH2	South Hydrogen Corridor Project (PCI)
TAG	Trans Austrian Pipeline
TAP	Trans Adriatic Pipeline
TEN-E	Trans-European Networks for Energy
TEN-T	Trans-European Transport Network
TRANSGAZ	Romanian TSO
TSO	Transmission System Operator
TYNDP	10-Year Network Development Plan
WACC	Weighted Average Cost of Capital

1 Introduction

1.1 EU policies, regulations & initiatives

Renewable hydrogen and biomethane have gained significant attention especially since the publication of the REPowerEU Plan in 2022[14], which aims to reduce the dependence on Russian fossil fuels and accelerate the green transition. More specifically, the REPowerEU Plan envisages the production of 10 million tonnes (Mt) of renewable hydrogen in the EU and the import of up to 10 Mt of renewable hydrogen from third countries (with the expectation that supply capacity for transporting hydrogen into Europe is established). Higher levels of consumption, up to the 20 Mt of hydrogen, announced in the very same communication is assumed to be primarily delivered from third countries in the form of ammonia and potentially in the form of other hydrogen carriers and derivatives. On the demand side, hydrogen is expected to be consumed in traditional, as well as in new applications. The former include primarily refining, the chemical industry (as feedstock), the steel industry (as reducing agent), and glassmaking. Potential new applications of hydrogen encompass its use as a reducing agent in 100% hydrogen-based direct reduced iron (DRI), transport, synthetic fuels, high-temperature heating in industry, electricity storage and generation, etc. Figure 1 illustrates the use of hydrogen per sector by 2030, as this is modelled in PRIMES[15], and underpins its primary use for applications in hard-to-abate sectors.

Figure 1 Hydrogen use by sector in 2030



Source: REPowerEU SWD (2022) 230 final

With respect to biomethane, the so-called Biomethane Action Plan – Chapter 5 of the Staff Working Document[16] accompanying the REPowerEU Plan defines a series of actions to help achieve the target of 35 billion cubic meters (bcm) annual biomethane production by 2030, among which the following are mentioned:

- Create a Biomethane Industrial Partnership[17] promoting the production and use of sustainable biomethane (launched on 28 September 2022).
- Develop national strategies on sustainable biogas and biomethane production and use or integrate a biogas and biomethane component in the National Energy and Climate Plans (NECPs).

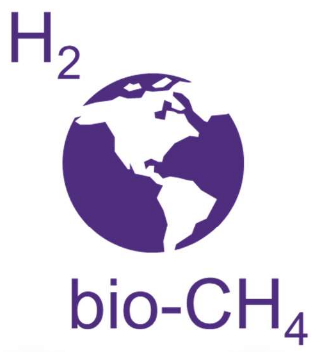
[14] COM(2022) 230 final, https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF
[15] Model used by the European Commission
[16] SWD(2022) 230 final
[17] https://bip-europe.eu/

- Reduce red tape and speed up permitting.
- Reduce the costs for producers, which currently prevent biogas upgrading into biomethane.

The EU has a comprehensive policy framework concerning hydrogen and facilitating its uptake. Following the EU Hydrogen Strategy (2020)[18], the EU gradually developed the regulatory framework, which includes the REPowerEU Plan and a series of legislative initiatives – some of which are already in force at the time of writing. Figure 2 gives an overview of what has been in place to date.

[18] eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301

Figure 2 European policy, regulatory frameworks and initiatives concerning hydrogen and biomethane



1

REPowerEU Action Plan

Aims to reduce the dependence on Russian fossil fuels and accelerate the green transition. Sets targets for renewable hydrogen production and imports and for biomethane production.

2

EU Hydrogen Strategy

Recognises the important role of hydrogen in decarbonising industrial processes and other hard-to-abate sectors of the economy. Sets a target of a 40 GW electrolyser capacity for 2030.

3

EU Taxonomy Regulation

A voluntary tool to channel investments into sustainable economic activities. It defines under what conditions economic activities, including those related to hydrogen, are to be considered environmentally sustainable

4

RED III

Stipulates that 42% of the hydrogen used in industry by 2030 and 60% by 2035 will be renewable. In the transport sector, renewable hydrogen should contribute at a minimum of 1% in the share of renewable energies by 2030

5

Revised TEN-E Regulation

*New infrastructure categories that promote the **uptake of hydrogen**. End of policy and financial support for fossil fuel projects (including cross-border natural gas infrastructure)*

6

EU Hydrogen Backbone Initiative (EHB)

The European Hydrogen Backbone (EHB) initiative consists of a group for 33 energy infrastructure operators and its vision is to connect regions with abundant renewable hydrogen supply potential with centres of demand through the development of a comprehensive hydrogen transportation network across Europe

7

EU Hydrogen and Decarbonized Gas Market Package

The goal is to create a competitive EU hydrogen market and to enable the market to decarbonise gas consumption.

8

Delegated Acts on RFNBO

Two acts elucidating the criteria for hydrogen classification and introducing life cycle GHG emissions associated with RFNBOs

9

Alternative Fuel Infrastructure Regulation (AFIR)

Crucial legislative measure for the advancement of hydrogen mobility as it defines mandatory national targets for establishing hydrogen refueling stations (HRS) and the infrastructure necessary for electromobility

Already in 2020, the **EU Hydrogen Strategy**[19] recognised the important role of hydrogen in decarbonising industrial processes and other hard-to-abate sectors of the economy. The Strategy sets a target of a 40 GW electrolyser capacity for 2030 corresponding to 10 Mt of renewable hydrogen produced and in overall foresees a gradual trajectory for hydrogen deployment in Europe taking place in three different phases. More specifically, in the short-term phase until 2024, the focus is on producing renewable hydrogen (1 Mt with a target of a 6 GW electrolyser capacity) for existing applications, such as the chemical industry. In the medium-term phase until 2030, the rollout of electrolysers is supposed to increase its pace with hydrogen conquering new application fields including the role of energy carriers in energy-intensive industries (e.g., steel) and diverse transport applications. Finally, in the long term, from 2030 onwards, the use of renewable hydrogen will spread to new application where it provides increased GHG emission reductions.

In the same year, the **EU Taxonomy Regulation** (EU) 2020/852[20] enters into force as a classification system that stipulates under which conditions (i.e., the technical screening criteria - TSC) an economic activity can be considered environmentally sustainable. Its purpose is to guide investments towards economic activities crucial for transitioning, aligning with the objectives of the European Green Deal. For an economic activity to qualify as environmentally sustainable, it must meet the substantial contribution TSC of one out of the six environmental objectives[21], while at the same time comply with the "do no significant harm" (DNSH) principle TSC for the remaining five environmental objectives. An example showcasing the type of criteria defined in the EU Taxonomy Delegated Act is hydrogen. In this case, the relevant economic activities up to November 2023 have been included only in the list of economic activities substantially contributing to the objective of climate change mitigation and adaptation environmental objectives. Furthermore, within the taxonomy, hydrogen activities hold a significant place. The connection between hydrogen activities and the EU taxonomy lies in the ability of the latter to attract investment towards sustainable hydrogen ventures. By defining criteria for sustainable economic activities, the EU taxonomy can effectively channel investment into hydrogen endeavours that adhere to environmental sustainability standards (See Annex A: EU Taxonomy – Technical screening criteria presents the TSC for substantial contribution to the climate change mitigation environmental objective).

In 2023, the Commission released two official **Delegated Acts stemming from the Renewable Energy Directive II (REDII)** detailing the EU's stance on renewable hydrogen[22].

The **Delegated Act on additionality**[23] sets the criteria, i.e., additionality, temporal and geographical correlation, according to which hydrogen and other Renewable Fuels of Non-Biological Origin (RFNBOs) produced via electrolysis are indeed considered renewable. It also includes relevant derogations.

As a result of the criteria, if a producer aims to produce renewable hydrogen, it must do so via one of the scenarios outlined:

- **Scenario 1:** The electrolyser is directly connected to the renewable energy installation. The renewable energy installation cannot come into operation earlier than 36 months before the electrolyser.
- **Scenario 2:** The electrolyser is situated in a bidding zone with an average renewable electricity production of over 90% in the previous year. The production of RNFBOs does not exceed a maximum number of hours set in relation to the proportion of renewable energy in the bidding zone.

[19] eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301
[20] Commission Delegated Regulation (EU) 2021/ of 4 June 2021 supplementing Regulation (EU) 2020/852 of the European Parliament and of the Council by establishing the technical screening criteria for determining the conditions under which an economic activity qualifies as contributing substantially to climate change mitigation or climate change adaptation and for determining whether that economic activity causes no significant harm to any of the other environmental objectives (europa.eu).
[21] Objectives are: climate change mitigation, climate change adaptation, sustainable use and protection of water and marine resources, transition to a circular economy, pollution prevention and control, protection and restoration of biodiversity and ecosystems [22] Renewable hydrogen production: new rules formally adopted [20 June 2023]. Available at: Renewable hydrogen production: new rules formally adopted (europa.eu)
[23] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R1184

- **Scenario 3:** The electrolyser is in a bidding zone where electricity's emissions intensity is under 18gCO2e/MJ of fuel input. Hydrogen producers must also have signed a renewable PPA and abide by the conditions of temporal and geographical correlation.
- **Scenario 4:** Power supply can be viewed as renewable if sourced from the grid during an imbalance period. The hydrogen producer must prove that either power-producing facilities using RES are redispatched downwards, or the electricity used for RNFBOs production decreased the need for redispatching by a similar amount.
- **Scenario 5:** A renewable PPA is signed for power supply, with additionality, temporal, and geographical correlation conditions applied.

The **Delegated Act on the GHG emission savings**[24] introduces a method for determining life-cycle greenhouse gas emissions associated with RFNBOs. It takes into consideration emissions associated with taking electricity from the grid, from processing, and those associated with transporting these fuels to the end-consumer.

In the same year, the amended **RED III** is adopted[25]. The new Directive aims to raise the share of renewable energy in the EU's overall energy consumption to 42.5% by 2030 with an additional 2.5% indicative top up to allow the target of 45% to be achieved. This target will be collectively achieved through the national contributions of each Member State, as spelled out in their NECPs [26]. All Member States will contribute also to achieving more ambitious sector-specific targets in transport, industry, buildings and district heating and cooling. The purpose of the sub-targets is to speed up the integration of renewables in sectors where incorporation has been slower[27].

When it comes to renewable hydrogen, RED III stipulates that it will specifically play a role in the transport and industry sectors. That said, RFNBOs[28] should contribute at a minimum of 1% in the share of renewable energies supplied to the transport sector by 2030 and they should also be the source of 42% of the hydrogen used in industry by 2030 and 60% by 2035. When calculating the share of renewable energy in a Member State, RFNBOs, namely renewable hydrogen and hydrogen-based synthetic fuels, should be counted in the sector where they are consumed (e.g., electricity, heating and cooling, transport). To avoid double-counting, the renewable electricity used to produce those fuels should not be counted in the renewable energy share. That would result in a harmonisation of the accounting rules for those fuels throughout Directive (EU) 2018/2001, regardless of whether they are counted for the overall renewable energy target or for any sub-target. It would also allow the real energy consumed to be counted, taking account of energy losses in the process to produce those fuels.

Moreover, it would allow RFNBOs imported into and consumed in the EU to be counted. Member States should be allowed to agree, via a specific cooperation agreement, to count the RFNBOs consumed in each Member State towards the share of gross final consumption of energy from renewable sources in the Member State where they are produced. Where such cooperation agreements are put in place, unless agreed otherwise, Member States are encouraged to count the RFNBOs as follows:

- Up to 70% of their volume in the country where they are consumed.
- Up to 30% of their volume in the country where they are produced.

[24] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R1185

[25] Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652 (europa.eu)

[26] The current NECPs were submitted in 2019. Member States were due to submit their final updated NECPs, taking account of the Commission's assessment and recommendations, by 30 June 2024

[27] Consilium, European Commision, Available at: https://www.consilium.europa.eu/en/press/press-releases/2023/10/09/renewable-energy-council-adopts-new-rules/

[28] RFNBOs are mostly renewable hydrogen and hydrogen-based synthetic fuels

With regards to biomethane, the amendments set out in this Directive are also intended to support the Union's target of an annual production of sustainable biomethane of up to 35 bcm by 2030[29], thereby supporting security of supply and the Union's climate ambitions.

An additional milestone reached in 2024 is the final agreement reached by the Parliament and the Council on the **revised Gas Directive[30]**, which is part of the **EU Hydrogen and Decarbonised Gas Market Package** together with the proposal for revision of the Gas Regulation. The revised Gas Directive aims to facilitate the penetration of renewable and low-carbon gas and hydrogen into the energy system enabling a shift from fossil gas and, to this end, includes numerous provisions. More specifically, it stipulates that requests for the grid connection of renewable gas production should be assessed within reasonable time limits and prioritises such connection requests at transmission and distribution level over connection request for the production of natural gas and low-carbon gas. In addition, it foresees a split between Transmission System Operators (TSO) and Distribution System Operators (DSO) for hydrogen, enforces vertical unbundling, and gives the right to the Member State to opt for full ownership unbundling on its territory. Furthermore, whereas the joint operation of hydrogen networks and natural gas or electricity grids can create synergies and should thus be allowed, legal horizontal unbundling is enforced. Derogations are acceptable only on a temporary basis and subject to a positive cost-benefit analysis and an impact assessment by regulatory authorities.

In resonance with the increasing importance of hydrogen and biomethane in the EU, the 2013 TEN-E Regulation (REGULATION (EU) No 347/2013)[31] was revised in order to introduce new infrastructure categories and seize policy and financial support for fossil fuel projects (including cross-border natural gas infrastructure). The new infrastructure categories include hydrogen transport, storage facilities, and receiving terminals, as well as smart gas grids for integrating renewable and low-carbon gases (such as biogas and renewable hydrogen) into the existing networks. In addition, for the first time, Projects of Mutual Interest (PMI)[32] are also introduced in the **revised TEN-E Regulation** (Regulation (EU) 2022/869)[33]. Projects of Mutual Interest (PMIs) are key cross-border energy infrastructure projects between the EU and non-EU countries, which contribute to the energy and climate policy objectives of the Union. The Energy Community countries also adopted and adapted the revised TEN-E Regulation. Upon its entry into force, it will repeal the old regulation on 31 December 2024.

On the end-use sector, the European Union's **Alternative Fuels Infrastructure Regulation (AFIR)** constitutes a crucial legislative measure for the advancement of hydrogen mobility. More specifically, it defines mandatory national targets for establishing hydrogen refuelling stations (HRS) and the infrastructure necessary for electromobility[34].

On the public support side, European Commission announced the creation of a **European Hydrogen Bank** (EHB)[35], which will be used to both kickstart and further accelerate the hydrogen economy by facilitating investment across its value chain. The first pilot auction of the EHB for the allocation of €800m to production projects of more than 5MW was launched in November 2023. It possesses two main pillars: the domestic (EU production of hydrogen and carriers) and international (EU imports of hydrogen carriers produced outside the EU), both of which involve support paid as fixed-price premiums of up to €4.5 per kilogram of hydrogen produced for 10 years to support hydrogen projects.

[29] https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF
https://www.consilium.europa.eu/en/press/press-releases/2024/05/21/fit-for-55-council-signs-off-on-gas-and-hydrogen-market- package/
[31] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009Text with EEA relevance (europa.eu)
[32] Projects promoted by the Union in cooperation with third countries
[33] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32022R0869
[34] The-Hydrogen-Europe-Quarterly_1_DIGITAL-FINAL.pdf (hydrogeneurope.eu)
[35] Hydrogen Europe, European H2 Bank auction and Innovation Fund, March 2023

Outside of the scope of the legislative and policy framework, but part of a coherent effort to accelerate Europe's decarbonisation journey, is the industry-led **European Hydrogen Backbone (EHB) Initiative**, which connects regions with abundant renewable hydrogen supply potential with centres of demand through the development of a comprehensive hydrogen transportation network across Europe that consists of a mix of existing and new pipelines able to accommodate hydrogen. The initiative involves the creation of five corridors[36], out of which Corridor A: North Africa & Southern Europe and Corridor E: East and South-East Europe are particularly relevant to the CESEC region.

1.2 CESEC region

The EU environment that governs the uptake of renewable hydrogen and biomethane, as it has been outlined so far, is key for the successful deployment of those renewable and low-carbon gases. This becomes even more relevant in the CESEC region, which exhibits high dependency on fossil fuel imports and a still limited diversity in its natural gas supply due to long term dependency on a single supplier.

The Central and South Eastern Europe Energy Connectivity High-Level Group (CESEC HLG) has committed to increase the deployment of renewable energy and to accommodate an increasing share of hydrogen and biomethane in the networks of the region. CESEC is one of the four High-Level Groups set up in 2015. Today's CESEC members are eight EU Member States – Austria, Bulgaria, Croatia, Greece, Hungary, Italy, Romania, Slovenia – and eight Energy Community Contracting Parties – Ukraine, the Republic of Moldova, Serbia, the Republic of North Macedonia, Albania, Bosnia and Herzegovina, Kosovo, and Montenegro [37]. Albeit the common goals of the countries participating in the CESEC HLG including the swift completion of cross-border and trans-European projects diversifying gas supplies to the region in tandem with the corresponding regulatory development, the state of play in the region with regards to the production and deployment of renewable and low-carbon gases has not been studied yet.

In light of this, the Ministers at the Ministerial meeting in Ljubljana in 2021 requested a study on the CESEC's region potential for renewable and low-carbon gas deployment in the context of infrastructure development. This report consists of the final deliverable of the study.

1.3 Objective of the study

The study's overall objective is to explore the potential for the production and deployment of renewable and low-carbon gases, specifically renewable hydrogen and biomethane, as well as their integration in the CESEC region focusing mainly on the infrastructure, digitisation and smartening of the grids, as well as opportunities for hydrogen-ready storage facilities. The overall objectives can be broken-down to **specific objectives**, as summarized in Table 1, matched with the respective chapters of the report.

Table 1 Specific objectives of the study

Objectives of the Study	Chapter addressed in the report
Technical and economic potential for the deployment of renewable and low-carbon gases	Chapter 3.2
National and market participants' plans of renewable and low-carbon gas deployment	Chapter 3.3
Technical readiness and specificities of the existing gas grid	Chapters 4.1 & 4.3

[36] Corridor A: North Africa & Southern Europe, Corridor B: Southwest Europe & North Africa, Corridor C: North Sea, Corridor D: Nordic and Baltic regions, Corridor E: East and South-East Europe
[37] Central and South Eastern Europe energy connectivity (europa.eu)

Objectives of the Study	Chapter addressed in the report
Infrastructure priorities and bottlenecks and recommendations to address them	Chapter 5.2
Infrastructure investment needs in new and repurposed infrastructure	Chapter 5.3
New markets for hydrogen and biomethane and identification of the future leading exporting countries in the region	Chapter 5.5
Promising areas for regional cooperation	Chapter 6

1.4 Structure of the report

The report is divided into 6 distinct Chapters.

Chapter 1 describes the operational background and explains the objectives and context of the study. The Chapter captures the most significant advancements in the EU policy environment concerning renewable hydrogen and biomethane, as well as important initiatives and developments.

Chapter 2 elaborates on the methodology used and the reasoning behind it. It describes the variety of methodological tools applied to address the objectives of the study and explains the rationale supporting the choices made.

Chapter 3 comprises the outcomes of the assessment of the production and consumption patterns of renewable and low-carbon gases in the CESEC region (including fossil-based hydrogen), as well as the prevailing policy and regulatory environment at country level. Part of the Chapter is also an analysis on the levelised costs of renewable hydrogen and biomethane production (LCOH and LCOB, respectively), including an illustration of how those are expected to differentiate from one country to another and across the years in the 2030-2045 timeframe.

Chapter 4 presents relevant information for the assessment of the infrastructure readiness to accommodate renewable hydrogen and biomethane in the region. It aims at illustrating the status of the infrastructure (i.e., transmission and distribution networks and storage sites) and at giving insight into the plans of the operators regarding their activities, including repurposing of existing assets and building new ones.

Chapter 5 gives an overview on the national investment plans, at TSO- and, to the extent possible, on DSO-level, concerning renewable and low-carbon gas deployment. In addition to the national plans, more sources of information on infrastructure projects promoted in the region are included. Special emphasis is placed on the CESEC projects included in the 1st PCI/PMI list under the revised TEN-E Regulation. This Chapter also elaborates on the possible infrastructure priorities based on the infrastructure readiness and continues with a comparative analysis of the three main transportation modes of hydrogen. Moving the focus to hydrogen networks specifically, Chapter 5 presents the modelling approach and the employed assumptions, as well as the results indicating expected cross-border flows of hydrogen in the time horizon 2030-2050. In addition, the Chapter includes an overview of the relevant investment costs concerning the transportation, reception, and storage of pure hydrogen. Chapter 5 ends with a discussion on the challenges for infrastructure development and potential criteria and indicators for identifying and assessing key cross-border infrastructure projects that could be supported within the CESEC HLG.

Finally, Chapter 6 contains conclusions after carrying out the study, provides key remarks and recommendations with regards to the improvement of the regulatory framework, policy development, enabling market conditions, critical for the uptake of renewable gases as well as the role of the CESEC High-Level Group in implementing the conclusions.

2 Methodological approach

The approach followed for the implementation of the study relies on a combination of tools, such as analysis of publicly available data and studies, elaboration of a full-fledged survey, carry out of complementary interviews with key stakeholders, organization of a stakeholders' workshop and modelling.

Initially, desktop research is conducted to identify the relevant targets set by each of the countries in the CESEC region, source the latest available data on production and consumption of renewable and low-carbon gases and identify the planned production plants and key infrastructure. In this context, the National Energy and Climate Plans (NECP) of the CESEC countries, as well as the National Hydrogen Strategies (NHS), wherever available, the Union-wide Ten-Year Network Development Plans (TYNDP) 2022 of ENTSOG[38], the NDPs of the TSOs and of the DSOs, the 1st PCI/PMI list under the revised TEN- E Regulation, the Hydrogen Project Visualisation Platform of ENTSOG and the Hydrogen Infrastructure Map have been assessed. Moreover, an online survey based on questionnaires that differentiates depending on the type of key stakeholder (i.e., TSO, DSO, National Regulatory Agencies (NRAs), etc.) is launched. Finally, interviews with targeted stakeholders are conducted to facilitate the information flow, as well as in cases when clarifications on the responses in the survey are needed.

Levelised costs of renewable hydrogen and biomethane production (LCOH and LCOB, respectively) are calculated, including an estimation across the years of the studied horizon of 2030-2050 including the different countries in scope. Moreover, a calculation of the techno-economic potential for renewable hydrogen production takes place by considering the already mapped potential for renewable electricity generation and the needs of the electricity system, which are considered to be a priority. The results of this analysis serve as the maximum renewable energy potential that can supply the electrolysers installed in the region. The techno-economic potential for biomethane production is calculated following the approach presented in the Gas for Climate Report "Biomethane production potentials in the EU"[39].

With regards to infrastructure readiness, an assessment of their ability to accommodate renewable hydrogen and biomethane in the region is conducted with a focus on the current status of the infrastructure (i.e., transmission and distribution networks and storage sites). The activities and plans of the operators regarding testing of their existing infrastructure, construction of new and repurposing of actual infrastructure are also presented. To this end, a high-level overview of the national investment plans, at TSO- and, to the extent possible, at DSO-level, concerning renewable and low-carbon gas deployment is provided. The analysis focuses on the main infrastructure bottlenecks, and the infrastructure adaptation needs for pure hydrogen transportation, reception and storage.

Finally, in order to assess the future cross-border flows of renewable hydrogen between EU Member States and Energy Community Contracting Parties, a modelling analysis is implemented utilising PLEXOS software. As a result of the same analysis, the investment needs in terms of capacity and CAPEX for major transmission infrastructures are estimated.

In the following sections, key aspects of the methodological approach are presented.

2.1 Literature review

The desktop research serves the identification of relevant and publicly available reports, studies, and databases. It is utilised specifically to source the latest available data on production and consumption of fossil, renewable and low-carbon gases, the relevant targets set by each of the countries in the CESEC region, the planned production plants and infrastructure, the infrastructure costs as well as the cost drivers associated with the production of renewable hydrogen and biomethane. Key sources of information that are retrieved and analysed as means to give an overview on national policies and the national investment

[38] https://www.entsog.eu/sites/default/files/2023-09/ENTSOG_TYNDP_2022_Infrastructure_Report.pdf
[39] Guidehouse_GfC_report_design (europeanbiogas.eu)

plans at TSO-level and, possibly, at DSO level, concerning renewable and low-carbon gas deployment include:

- The **National Energy and Climate Plans** (NECP) of the CESEC countries[40].
- The **National Hydrogen Strategies** (NHS), wherever available, are analysed in view of the production targets and the supply and demand forecasts.
- The Union-wide **Ten-Year Network Development Plan 2022** (TYNDP)[41].
- The national **Network Development Plans** (NDP).
- The **1st PCI/PMI list under the revised TEN-E Regulation**.
- The **Hydrogen Project Visualisation Platform** of ENTSOG[42].
- The **Recovery and Resilience Plans** (RRPs) are consulted to identify funds allocated to hydrogen and biomethane projects at national level.
- The **Hydrogen Infrastructure Map**[43]. Other sources of information include:
- The **Gas for Climate report**[44], the **ENGIE report**[45], the **Guidehouse report**[46] and the **BIP Europe report**[47] for the cost components involved in the production of biomethane.
- The **Hydrogen Europe report**[48] and the **2020 Reference scenario technology assumptions report**[49] for the identification of the cost components and of the critical parameters overall involved in the production of renewable hydrogen.
- The **Ecorys study**[50] on the Central and Southeastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables.
- The **Global Hydrogen Review 2023**[51] produced by IEA.
- The joined report by ENTSOG, GIE and Hydrogen Europe[52].
- The **Fraunhofer Study**[53] for the challenges linked to the transmission of hydrogen in its pure form.

For the assessment of capacity factors of renewable energy sources, the analysis leverages data from the following authoritative sources:

- The **EHB report** "*Analysing future demand, supply, and transport of hydrogen*"[54] which provides a comprehensive overview of the future demand, supply, and transportation needs for hydrogen in Europe.

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40 For Greece, Croatia, Hungary, Italy, Serbia, Slovenia, the draft updated NECPs as submitted to EC are used. For Albania, Austria and Bulgaria the NECPs are used
41 https://www.entsog.eu/sites/default/files/2023-09/ENTSOG_TYNDP_2022_Infrastructure_Report.pdf
42 Hydrogen project visualisation platform – ENTSOG
43 H2 Infrastructure Map Europe (h2inframap.eu) accessed in Q32023
44 Biomethane production potentials in the EU
45 Microsoft Word - ENGIE_20210618_Biogas_potential_and_costs_in_2050_report_v5[5].docx
46 Gas-for-Climate-Market-State-and-Trends-report-2020.pdf (consorziobiogas.it)
47 BIP_TF4-study_Full-slidedeck_Oct2023.pdf (bip-europe.eu)
48 Clean_Hydrogen_Monitor_10-2022_DIGITAL.pdf (hydrogeneurope.eu)
49 https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en
50 https://www.ecorys.com/app/uploads/files/2022-05/CESEC.pdf
51 Global Hydrogen Review 2023 (windows.net)
52 How to transport and store hydrogen – facts and figures found at: How to transport and store hydrogen – facts and figures (gie.eu)
53 Fraunhofer Conversion of LNG Terminals for Liquid Hydrogen or Ammonia Analysis of Technical Feasibility under Economic Considerations
54 EHB (2021), "*Analysing future demand, supply, and transport of hydrogen*"

- The **IRENASTAT Online Data Query Tool**[55] which provides detailed statistics on power capacity and generation, crucial for calculating the capacity factors of PV, onshore, and offshore wind energy.
- The **IEA report** "*Net Zero by 2050: A Roadmap for the Global Energy Sector*" [56] which provides a global overview of renewable energy transitions, with in-depth analysis vital for evaluating capacity factors in these energy sectors.

  Importantly, the information gathered based on publicly accessible sources is complemented by in-depth surveys and interviews to nuance and balance the evidence base of the study.

2.2 Surveys

An online survey based on questionnaires (see Annex B: Survey Questions) that differ depending on the type of key stakeholder (i.e., TSO, DSO, Ministries, NRA, etc.) is prepared and shared per email with an extensive list of recipients. The purpose of the surveys is to obtain recent insights in the developments at national level and complement the publicly available information, which specifically in terms of infrastructure readiness is very scarce. A list with the stakeholders approached is presented in Annex C: List of Stakeholders contacted.

Surveymonkey[57] is the tool used for the purpose of the survey. The survey allows for different modes of replies to the closed and open questions, e.g., multiple choice, upload file, ranking, text, etc. The thematic areas of the questions range from the production to the infrastructure-readiness and regulatory matters. The survey was open for a duration of 6 months and the identified participants have been encouraged to contribute within a given period of time. In cases when no responses were received, follow-up emails were sent, and the alternative of an online interview was proposed.

2.3 Interviews

Interviews with targeted stakeholders are conducted to complement the information base, and to provide clarifications to the survey, where needed. Interviews take place within 4 months and are bilateral. The interviewed stakeholders include: the Trans Adriatic Pipeline (TAP), the Greek Natural Gas System Operator (DESFA), Gas Infrastructure Europe (GIE), the Eurogas association, the Energy Regulatory Authority of Greece (RAE), the Ukrainian Gas Transmission System Operator (GTSOUA), the underground natural gas storage operator of Romania (DEPOGAZ), the Italian Gas Distribution Operator (Italgas), the Italian Energy Regulatory Authority (ARERA), the Energy Regulatory Authority of Kosovo (ERO), the Energy Regulatory Authority of Bosnia Herzegovina (FERK), the Gas TSO of Bosnia Herzegovina (BH-Gas), the Interconnector Greece-Bulgaria Operator (ICGB), the importer, wholesaler and retail supplier of Moldova (MoldovaGas) and the Gas TSO of Moldova (VestMoldTransgaz), the Energy Community Secreteriat (EnC), the Gas Distribution Operator (RGC), the Slovenian Gas TSO (Plinovodi), the Austrian Gas TSOs (GCA and TAGG), the European Biogas Association (EBA), the International Renewable Energy Agency (IRENA), the Hungarian Gas TSO (FGSZ), the Croatian Gas TSO (Plinacro), the gas TSO and storage Operator in Bulgaria (Bulgartransgaz), as well as the Italian Gas TSO (SNAM).

During the interviews, the stakeholders are briefed on the objectives of the study and are either asked to reply to some of the questions included in the survey questionnaire or clarify input that they already provided online. Three dedicated interviews with SNAM, DESFA and Bulgartransgaz, respectively, aim at validating

[55] IRENASTAT Online Data Query Tool: https://pxweb.irena.org/pxweb/en/IRENASTAT/IRENASTAT__Power%20Capacity%20and%20Generation/
[56] IEA (2021), *"Net Zero by 2050: A Roadmap for the Global Energy Sector"*: https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.
[57] www.surveymonkey.com

the demand assumptions employed in the PLEXOS modelling exercise.

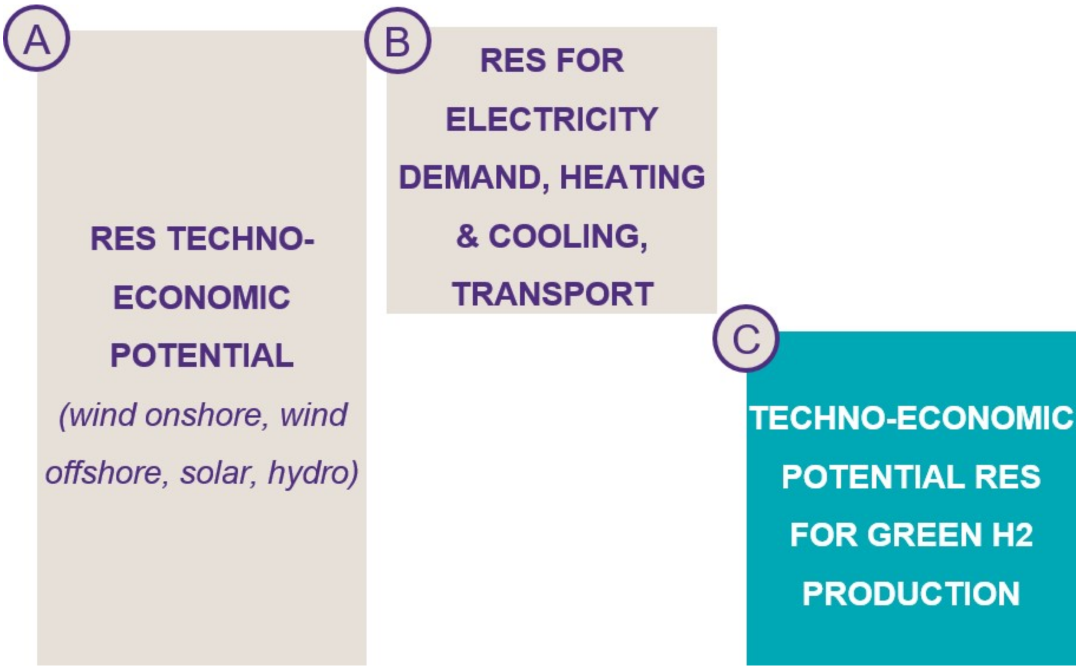
2.4 Techno-economic potential assessment

The "techno-economic potential assessment" is an assessment of the realisable technical potential, as this has been also defined in the Ecorys study on the Central and South Eastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables[58]. It considers both the technical aspects as well as the economic factors, such as costs. In other words, while technical potential focuses primarily on what is physically achievable, techno-economic potential considers whether achieving that potential is economically feasible and viable.

The potential for renewable hydrogen production is directly linked to the availability of renewable electricity. Thus, the prerequisite for the scale-up of the renewable hydrogen production in the CESEC region is the RES abundance, alongside sufficient water availability.Figure 3 schematically illustrates the methodological approach for the estimation of the remaining techno- economic RES potential for renewable hydrogen production at a given year. As reported in a recent study performed in the region by DG ENER based on a GIS approach ("*Study on the Central and South Eastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables*")[59], the CESEC countries have significant RES potentials (block A in Figure 3), as summarized in Table 3. Part of those is to serve the existing and forecasted needs for power generation including RES for 2030 for heating and cooling (i.e. heat pumps) and the RES for transport i.e. electromobility (block B in Figure 3). Given the fact that electrolysers constitute an electrical load, the remaining techno-economic RES potential for renewable hydrogen production for a specific year (block C in Figure 3) refers to the RES techno-economic potential (block A in Figure 3) minus the renewable generation for the electricity system (block B in Figure 3). Electricity generation needs (block B in Figure 3) for each specific country and year have been estimated via the resolution of the PLEXOS electricity model for the CESEC region, which is based on the EU Reference Scenario 2020 and adjusted to consider offshore wind capacity, which is not included therein. It is noted that RES for heating and cooling (heat pumps) and RES for transport (electric vehicles) are incorporated in the electricity demand projections made by Transmission System Operators and respectively used in the analysis. It is noted that block B in Figure 3 is expected to gradually increase across the years as the result of increasing targets in heating and cooling and of transport electrification. The PLEXOS electricity model (following the approach presented in Chapter 2.6) includes specific generators from each RES technology (i.e., PV, onshore and offshore wind, as well as fossil generation) installed in the individual CESEC countries and jointly serve the electricity demand in the region. It is noted that the analysis refers to domestic RES resources and does not take into account the realisation of large- scale electricity interconnector projects with countries outside the region.

[58] https://www.ecorys.com/app/uploads/files/2022-05/CESEC.pdf
[59] https://www.ecorys.com/app/uploads/files/2022-05/CESEC.pdf

Figure 3 Illustrative depiction of the methodological approach for the estimation of the remaining techno-economic RES potential for renewable hydrogen production at a given year



Biomethane potential is inherently linked to the availability and sourcing ability of adequate feedstock. The current study adopts the methodology presented in the Gas for Climate Report "*Biomethane production potentials in the EU*"[60] and considers three different types of feedstocks for the production of biomethane. Those are agricultural residues (i.e., barley, maize, oat, rye, wheat), manure (i.e., cattle, cows, chickens, goats, sheep, pigs) and biowaste (i.e., animal and mixed food waste, vegetable waste).

Agricultural residues

As a first step, the current production volumes (wet tonnes) for the selected crops in each of the countries are extracted from FAOSTAT[61] and the 2030 production volumes are estimated based on the EU-level growth forecasts per crop, as communicated in the European Commission's EU Agricultural Outlook 2021- 2031[62]. The 2050 production volumes are assumed to be the same as 2030 due to the fact that no data is available. The dry tonnes of the crop product are calculated prior to calculating the theoretical potential of agricultural residues. The latter is based on the "crop-to-residue index"[63], which is specific to each crop and varies from one country to another. In the next step, the sustainable theoretical potential of agricultural residues is calculated by applying the "sustainable removal rates"[64] relevant for each country. Sustainable potential is the share of the theoretical agricultural residue that – upon its removal from the field – does not impact negatively the quality of the soil. The sustainable potential assumed to be required for existing uses is subtracted. In addition, it is assumed that the effectiveness of the supply chain in 2030 enables, on average, only 60% of the available potential to be utilised for biomethane production (i.e., sustainable and realisable potential available for biomethane production). By 2050, it is assumed that supply chains will improve and, thus, 100% of the available potential can be realised, in the sense that all available feedstocks will be collected and aggregated. The sustainable and realisable potential available for biomethane production is

60 Guidehouse_GfC_report_design (europeanbiogas.eu)
61 https://www.fao.org/faostat/en/#data/QCL
62 agricultural-outlook-2021-report_en_0.pdf (europa.eu)
63 Integrated and spatially explicit assessment of sustainable crop residues potential in Europe, Biomass and Bioenergy 122: 257-269
64 Integrated and spatially explicit assessment of sustainable crop residues potential in Europe, Biomass and Bioenergy 122: 257-269

converted to biomethane using the production yields specific to each crop type.

Animal manure

The number of livestock per type (i.e., cattle, cows, chickens, goats, sheep, pigs) and country are retrieved from the EUROSTAT database[65] and the 2030 projections are calculated via applying the growth forecasts in European Commission's EU Agricultural Outlook 2021- 2031[66]. The 2050 numbers are assumed to be the same as 2030 since no data is available. In the next step, the theoretical potential of animal manure is calculated based on the typical manure production volumes per animal type. In the following, the solid content of the manure and the volatile content of the solid content are calculated for each of the animal types. This yields the volatile theoretical potential. Considering that only the manure produced in stables or barns can be collected, the technical potential is assumed to be a portion of the volatile theoretical potential, the share of which depends on the animal type. Then, inefficiencies in the supply chain are assumed to allow for 70% of the technical potential to become realisable, i.e., accessed for biomethane production, by 2030. By 2050, it is assumed that supply chains will improve and, thus, 100% of the available potential can be realised. The realisable manure potential available for biomethane production is converted to biomethane using the methane yield specific to each animal type.

Biowaste

Biowaste feedstocks included in this study are animal and mixed food waste and vegetable waste. Their quantities are retrieved from the EUROSTAT database[67]. As per the deliverable "*Guidelines for data collection to estimate and monitor technical and sustainable biomass supply*"[68], the part of the waste that can be seen as potential for biomethane potential is calculated based on the waste treatment data also reported in the EUROSTAT database[69]. In the next step, the biowaste potentials for biomethane production by 2030 and 2050 are calculated based on the population growth trends (retrieved by Statista[70]). Subsequently, it is assumed that 60% of biowaste is separately collected and available for anaerobic digestion in 2030, and 55% in 2050, yielding the technical realisable potential. The technical realisable biowaste potential available for biomethane production is converted to biomethane by applying the biogas yield and the assumption of 57% methane content in the biogas.

2.5 Cost analysis

In order to calculate the production costs of biomethane and renewable hydrogen in each of the countries, an excel-based modelling analysis is conducted, which considers all CAPEX and OPEX elements of an electrolyser project and the generation plants that are needed for the supply of renewable electricity, through the lifetime of the project. The risk of investments, that is different across a region and represented by the Weighted Average Cost of Capital (WACC), is an additional parameter influencing the LCOH and taken into consideration in the model. With regards to renewable electricity costs, it is assumed that the electrolyser is supplied by the grid. Thus, the electrolyser utilizes the RES mix of the individual country, with the respective renewable electricity costs and grid transmission costs[71]. It is noted that the calculated LCOH only covers hydrogen production costs, i.e., does not include additional costs of hydrogen compression (or liquefaction) and transportation. Costs associated with large-scale storage are not included either in the calculations. The study adopts the renewable energy generation cost assumptions (i.e., CAPEX unit costs and operating and

[65] Statistics | Eurostat (europa.eu) Statistics | Eurostat (europa.eu)
[66] agricultural-outlook-2021-report_en_0.pdf (europa.eu)
[67] https://ec.europa.eu/eurostat/databrowser/view/env_wasgen/default/table?lang=en&category=env.env_was.env_wasgen
[68] https://spiral.imperial.ac.uk/bitstream/10044/1/76345/2/IEE%2012%20835%20D2%202%20Guidelines%20for%20data%20collection%20to%20estimate%20and%20monitor%20biomass%20supply.pdf
[69] https://ec.europa.eu/eurostat/databrowser/view/env_wasgen/default/table?lang=en&category=env.env_was.env_wasgt
[70] https://www.statista.com/topics/769/demography/#topicOverview
[71] It is assumed that electrolysers are in general connected to the High Voltage network. The option of a direct line whereas it is always a feasible option is considered to be not financially attractive for RES developers and electrolyser operators, because it leads to the underutilization of both assets. Moreover, in order to supply utility scale electrolysers large surface is required for the installation of RES and a combination of solar and wind is not always feasible.

maintenance unit costs for PV, onshore and offshore wind) reported in the 2020 Reference scenario technology assumptions report[72] and the electrolyser cost assumptions reported in the Hydrogen Europe report[73]. The RES capacity factors are obtained from "*Analysing future demand, supply, and transport of hydrogen*" report by EHB[74], data from the IRENASTAT Online Data Query Tool[75] , and the IEA's report "*Net Zero by 2050: A Roadmap for the Global Energy Sector*"[76] and presented in Annex D: Capacity factors. In respect to the water treatment costs, it is noted that those are among the minor cost drivers provided that such facilities already exist[77].

A similar analysis is conducted for the estimation of levelised cost of biomethane (LCOB). The most pronounced cost drivers are the cost of the biodigesters, the feedstock cost and the cost of the upgrade and injection unit. The digestate management cost is also taken into consideration. Important challenge in the production of biomethane is the biomass supply chain management, i.e., the collection of biomass at the agricultural field. The low bulk density of biomass composition necessitates automated and mechanized techniques for collection, transportation and pre-treatment that contribute to the reduction of the biomass feedstock significantly. The deployment of those techniques is reflected into the roadside cost of the feedstock cost. The overall feedstock cost is the sum of the roadside cost and the transportation cost. The latter is the cost between the farm gate and the conversion plant gate. The cost of biomass transportation is affected by several factors, such as the distance between the plant and the field, available infrastructure, on-site technology, and ways of transportation (e.g., trucks, railway, vessel, etc.). The model is built on the value chain approach, as per the ENGIE report[78], and considers trucks as transportation means of the feedstock. In all cases, it has been assumed that the distance to cover from feedstock site to the processing facility is 20 km in the case of agricultural crops and biowaste and 10 km in the case of animal manure. The methodology also assumes different sizes of plants across the region, following the Gas for Climate report[79]. The CAPEX and OPEX unit costs are obtained from the Guidehouse and BIP Europe reports[80,81].

It is noted that key assumptions applicable to the LCOH and LCOB calculations are included in Annex E: Levelised cost of hydrogen and biomethane input data.

2.6 Infrastructure planning via PLEXOS

A modelling exercise is carried out to approximate the future cross-border flows of renewable hydrogen between EU Member States and Energy Community Contracting Parties. PLEXOS software, a comprehensive mathematical modelling tool, excels in solving complex mathematical optimisation problems through robust algorithms and is considered one of the key tools for modelling and analysing the energy market. Its versatility makes it an invaluable asset for long term infrastructure planning within the energy sector.

In general terms, the PLEXOS model is designed to encompass a wide array of model objects, covering the entire spectrum of energy generation, transmission, distribution and storage. This includes, among others, the modelling of various types of generation using natural gas, lignite, nuclear power, renewables, storage facilities such batteries, underground gas storages, terminals. Furthermore, it incorporates transmission for electricity, as well as pipelines for natural gas and hydrogen.

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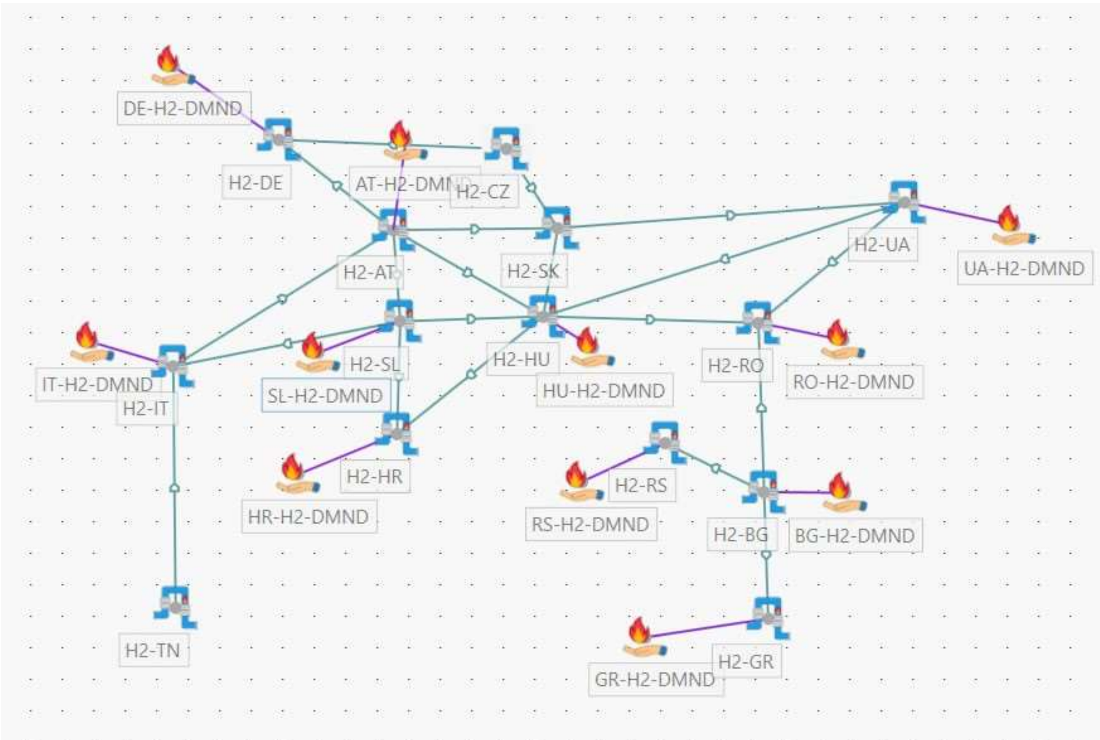
[72] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en
[73] Clean_Hydrogen_Monitor_10-2022_DIGITAL.pdf (hydrogeneurope.eu)
74 EHB (2021), "*Analysing future demand, supply, and transport of hydrogen*"
[75] IRENASTAT Online Data Query Tool: https://pxweb.irena.org/pxweb/en/IRENASTAT/IRENASTAT__Power%20Capacity%20and%20Generation/
[76] IEA (2021), *"Net Zero by 2050: A Roadmap for the Global Energy Sector":* https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.
[77] Agora Industry and Umlaut (2023): Levelised cost of hydrogen. Making the application of the LCOH concept more consistent and more useful
[78] https://www.engie.com/sites/default/files/assets/documents/2021- 07/ENGIE_20210618_Biogas_potential_and_costs_in_2050_report_1.pdf
[79] https://gasforclimate2050.eu/wp-content/uploads/2023/12/GfC_MarketStateTrends_2023.pdf
[80] Gas-for-Climate-Market-State-and-Trends-report-2020.pdf (consorziobiogas.it)
[81] BIP_TF4-study_Full-slidedeck_Oct2023.pdf (bip-europe.eu)

One of the standout features of PLEXOS is its ability to tackle demand-driven problems. It operates by deploying the necessary infrastructure to fulfil the required energy demand within the region over a specified time horizon. It then optimises the energy flows, ensuring that the demand is met efficiently and effectively.

The model is based on two modules: one for power and one for hydrogen. The aim of the method is to simulate the development of a hydrogen system in the region that already has pre-existing power system. The modelling exercise is demand driven, meaning that it takes as input hydrogen and power demand of different CESEC countries. It is assumed that hydrogen demand comprises primarily industrial consumption and consumption in transport (long-haul heavy-duty road, aviation, maritime)[82]. For detailed description of the demand input, please see Section 5.3.2. In one of the two assessed scenarios (see Section 5.3, Scenario B), demand in Germany is considered as well.

The objective is to achieve the mathematically optimal and cost-efficient satisfaction of demand by optimising the creation of the most economic transmission infrastructure. An overarching assumption is that all hydrogen produced after 2030 in all countries will be renewable hydrogen, supplied through electrolysers connected to the high-voltage grid. The model is capable of establishing electrolyser capacity and incremental renewable energy sources to supply them in each country. It also deploys the necessary transmission infrastructure to ensure optimal hydrogen flow in the CESEC region. A schematic representation of the hydrogen transmission system in PLEXOS in the CESEC region is presented in Figure 4. Deployed electrolyser capacity is also considered outside the CESEC region in the scenario including North African hydrogen production (see Section 5.3, scenario B), as presented in following sections.

Figure 4 Simplified version of the hydrogen transmission system in PLEXOS in the CESEC region



The analytical framework for conducting least-cost infrastructure planning utilises a wide array of assumptions regarding the evolution of the electricity generation mix, considering system needs, existing

[82] eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CONSIL:ST_7909_2023_INIT

electricity and gas transmission infrastructure, as well as candidate hydrogen infrastructure projects in each country. These assumptions are derived from national policy and strategic documents (such as NECPs, NHSs, TYNDPs, etc.).

For optimal hydrogen transmission network deployment, the model assumes the development of dedicated cross-border hydrogen transportation capacity through conventional steel high-pressure pipeline networks. The modelling analysis does not differentiate between re-purposing of existing natural gas pipeline networks and developing new ones. It derives cross-border flows and necessary transmission infrastructure capacity without distinguishing between the two. It is acknowledged that certain PCI projects, such as the SoutH2 Corridor, include extensive repurposing.

The model considers all the hydrogen PCI projects that are included in the 1st PCI/PMI list. A list of proposed hydrogen transmission projects for dedicated hydrogen pipelines is also incorporated, assuming predefined transmission capacities based on the data published in the Union-wide TYNDP of ENTSOG. The model optimises the deployment of cross-border infrastructure and specifically the commissioning year, the borders and the transmission capacity of pipelines, on top of the PCI projects which are included in any case under Scenario B.

Beyond the categories of transmission projects and for the period extending after 2034, the model is allowed to build incremental hydrogen transmission infrastructure as needed to address cross-border demand/supply imbalances and minimise total system costs for the period to 2050. It is noted that hydrogen, ammonia, and methanol terminals were not considered in the analysis, as these are deemed immature at the current timeframe in the CESEC region, unlike in Northern Europe where ammonia terminals are under development (such as in Germany, Belgium and Netherlands). Moreover, no solid reference is made in the context of NECPs of the CESEC countries with regards to hydrogen and hydrogen derivatives terminals. However, these should be further analysed in future studies commissioned by DG ENER or other entities.

To represent demand, national dedicated hydrogen nodes are established in each country (i.e., each country is represented as one single node for the purposes of the present analysis) where hydrogen demand is envisaged, with hydrogen cross-border flows occurring between these nodes, if and when applicable. The model can effectively meet hydrogen demand among countries by supplying demand through nationally produced hydrogen or via imports, while optimising hydrogen pipeline deployment based on relative cross-country costs, demand, and available transportation capacity. The optimal planning of the system and the model's decision to deploy new transmission infrastructure (apart from the PCI/PMI projects) are based on the LCOH in a specific country, adequacy of production, and hydrogen transportation tariffs. Regarding hydrogen storage, incremental storage facilities are also chosen freely, with the model remaining technology and cost agnostic (i.e., between salt caverns and other on-ground technologies). Practically, this means that limited storage capacities are deployed in certain countries to smooth seasonal flow variations (such as excessive peaks in demand) and avoid deployment of extreme electrolyser capacity.

In Sections 5.3.2 the demand for hydrogen is presented while in Section 3.2 the levelised costs for renewable hydrogen and biomethane production is estimated. Moreover, in Section 3.2 the techno-economic potential for renewable hydrogen and biomethane has been presented. A graphical representation of inputs and outputs of the PLEXOS hydrogen model is provided in the Figure 5 and key sources of information are presented in Table 2.

Figure 5 Graphical representation of PLEXOS inputs and outputs

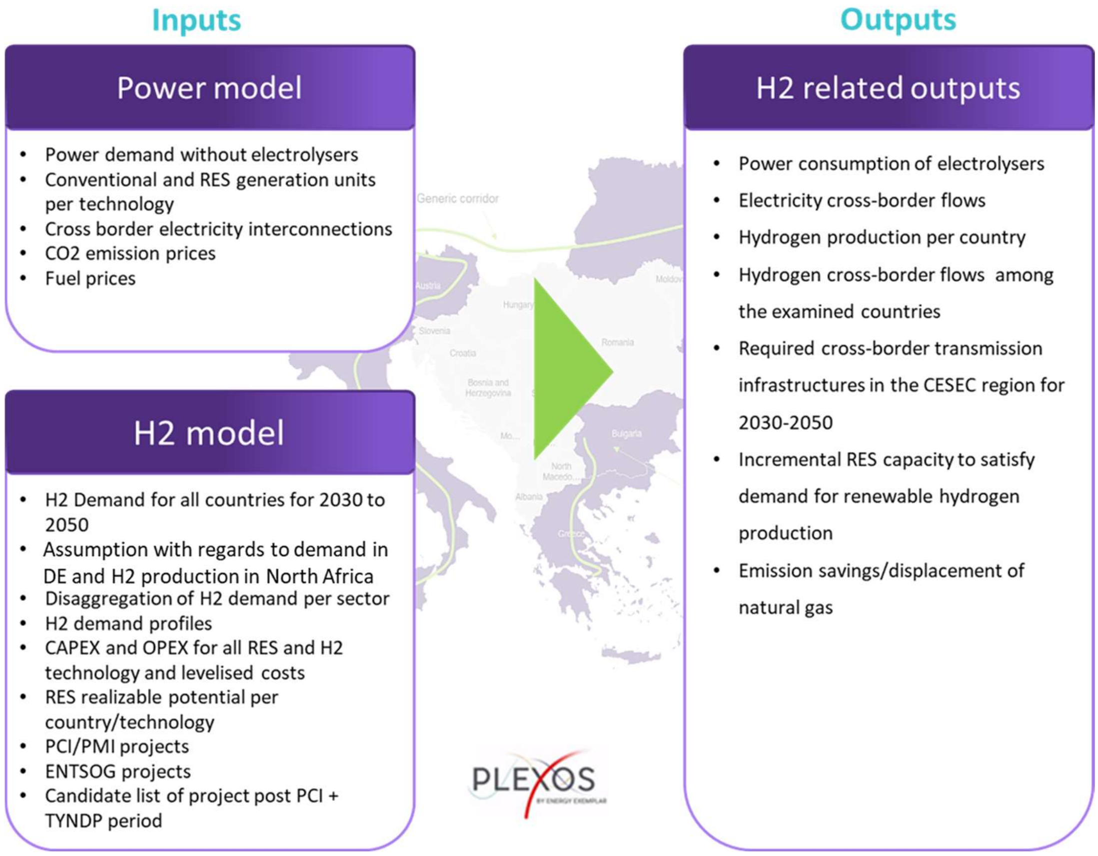


Table 2 Key assumptions and respective sources for the modelling analysis

Assumption	Key data sources[83]	Section
Power model		
Electricity interconnections	ENTSOE data and TYNDPs	5.3.2
Electricity demand	Demand forecasts by TYNDPs and NECPs	5.3.2
Electricity system installed capacities	EU reference scenario 2020	5.3.2
CO_2 prices	Own assumptions and Bloomberg New Energy Finance data	5.3.2
Natural gas prices	TTF futures and own analysis	5.3.2
Hydrogen model		
Hydrogen demand data	NECPs, NHS, PCI/PMI process needs, German Hydrogen Strategy	3.3.1 and 5.3.2
Sectoral split of hydrogen consumption	Own assumptions based on NECP/NHS data	5.3.2
Levelised cost of hydrogen	Own analysis based on CAPEX and OPEX data from Hydrogen Europe for electrolysers and the 2020 Reference scenario technology assumptions report for RES	3.2
Capacity Factors for RES technologies	EHB, IRENASTAT, IEA, NREL	3.2
RES techno-economic potential	Own analysis based on EU study (Ecorys)	3.2
PCI/PMI project data (year of commissioning, capacities, etc.)	Project promoters' data and interviews with stakeholders	5.3.2
Candidate hydrogen infrastructure projects (year of commissioning, capacities, etc.)	ENTSOG Union-wide TYNDP	5.3.2
Hydrogen demand profiles	Own assumptions based on natural gas profiles	-

It is worth noting that a number of challenges were encountered during the modelling analysis and presented thereafter, together with certain limitations of the study.

Policy and regulatory framework assumptions

- There are major difficulties in mapping demand in almost all countries due to the long-term horizon of the analysis, uncertainty with regards to policy development, constantly evolving and sometimes overlapping targets set in various policy documents.
- Countries, when designing national hydrogen policies, due to the emerging nature of the market and the fact that regional coordination (unlike natural gas and electricity) can be further enhanced, inevitably place emphasis on national hydrogen production, either instead of or complementary to imports.
- For the purposes of the modelling analysis, demand in all countries is typically derived as the result of linear extrapolation between specific timeframes (2030 and 2050) for which clear policy targets were set, though this pattern might not materialise. Additionally, a robust approximation of

[83] Detailed references are provided in relevant sections of the document.

the German hydrogen demand to be satisfied from the CESEC region is a source of uncertainty.

- Hydrogen and hydrogen carrier terminals are not included in the analysis. In the coming years, as more analysis is conducted regarding their technological and economic feasibility, they could significantly alter the regional landscape and flows.

Infrastructure deployment assumptions

- Apart from synergies, there is an inherently competitive relationship between electricity and hydrogen transmission infrastructures particularly regarding imports/exports.
- There is inherent uncertainty regarding the timing and modelling of the flow from North Africa to Europe, due to the significant need for RES/electrolyser capacities to be developed in North Africa.
- Without knowledge of the mix and costs of new dedicated versus repurposed pipelines, deriving transportation tariffs (calculated as average costs plus a reasonable WACC/margin) is challenging, unlike for electricity and gas interconnectors.
- The feasibility and costs of hydrogen storage are largely unknown, factors that largely influence modelling results.

3 CESEC region's potential for the production and deployment of renewable and low-carbon gases

3.1 Introduction

Chapter 3 provides an overview of the production and consumption of renewable hydrogen and biomethane in the CESEC region, based on the most current data available online. It highlights the emerging momentum in renewable hydrogen production, which was absent in the region as of 2022. If all announced projects in the region (to the best of Consultant's knowledge) are to become operational by 2030 (totalling 30.9 TWh[84]), renewable hydrogen production in the region alone is expected to approach the target of 10 million tonnes (equivalent to 39 TWh[85]) set in EU by 2030. Chapter 3 also underscores the need to foster biomethane production, noting its current low volume of 0.24 TWh, which is localised only in the four countries in the CESEC region.

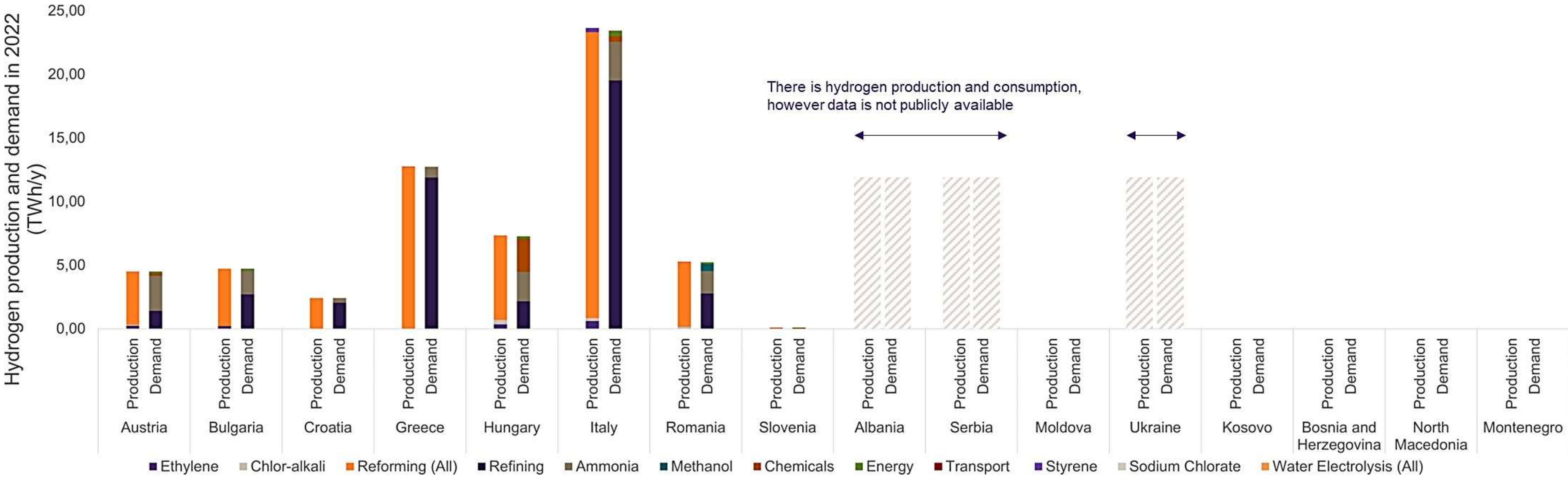
Considering that the driving force for the deployment of renewable hydrogen and biomethane is the technical and economic potential, Chapter 3 includes an analysis of the levelised costs of production for each of the molecule. In presenting a holistic view of the region, Chapter 3 also reviews the strategic documents at national level published by the countries to date and highlights varying priorities across the region based on different targets. A mapping of the legislative environment and of existing incentives in the region are also presented. The Chapter concludes with an overview of the key benefits of a fuel switch from fossil gas to renewable and low-carbon gases, along with a summary of the main findings regarding the region's potential to produce and deploy them.

3.1.1 Renewable hydrogen

As of today (2023), production of hydrogen is mostly limited to captive[86] fossil-based hydrogen (produced via reforming) for large hydrogen consumers. No merchant renewable hydrogen production is reported to take place in the CESEC region in publicly available literature sources. In the CESEC region, only Italy appears to produce fossil-based hydrogen with carbon capture. Albania, Serbia and Ukraine are known to produce fossil-based hydrogen[87] but no specific data is publicly available. Moldova, Kosovo, Bosnia and Herzegovina, North Macedonia and Montenegro neither produce, nor consume hydrogen (see Figure 6).

[84] HHV H2 39 kWh/kg
[85] HHV H2 39 kWh/kg
[86] Hydrogen is produced on site for the exclusive use of the consumer – usually an industrial site using hydrogen as a feedstock.
[87] ECA, E4tech (2021). Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community Part III: Contracting Party assessment.

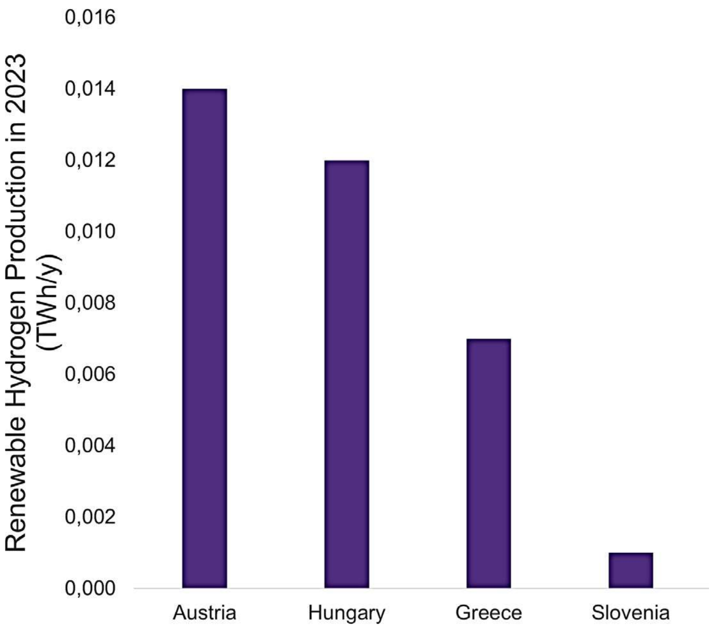
Figure 6 Hydrogen production and demand per technology and sector (2022 data), respectively



Source: Hydrogen Production | European Hydrogen Observatory (europa.eu); Surveys and interviews with Albanian and Serbian stakeholders

Very limited production of renewable hydrogen not exceeding 0.03 TWh/y in total takes place only in four countries in the CESEC region, as shown in Figure 7, as a result of projects that are either commercially operational or are in demonstration phase. Those projects utilise small-scale electrolysers, typically below 2 MW, except for Hungary (2MW). The most common use of the renewable hydrogen produced by those projects is in the transport power sector, followed by the power sector.

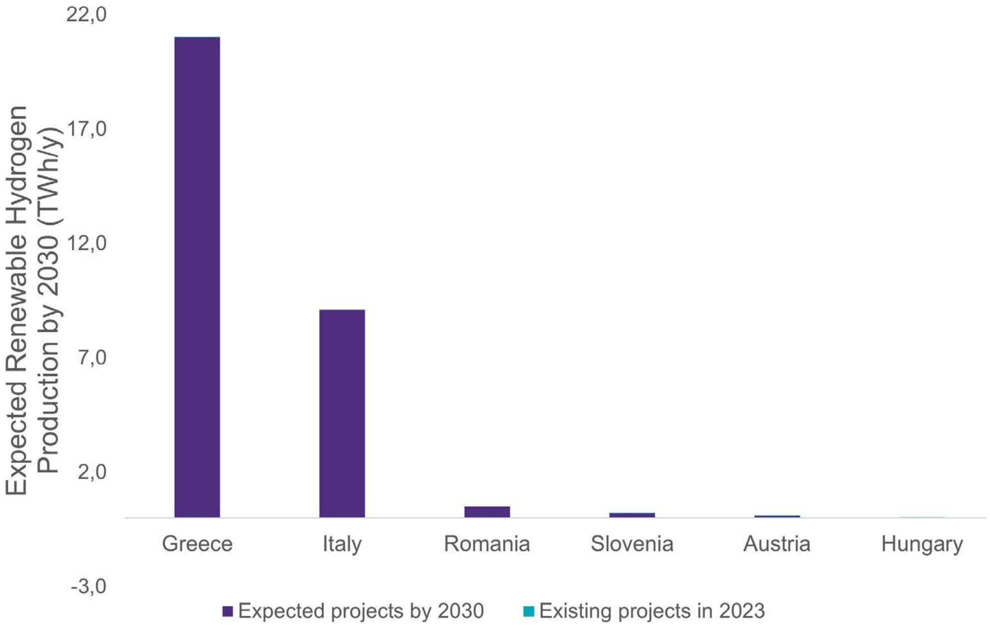
Figure 7 Renewable hydrogen production in 2023 based on commercially operational projects and projects in demonstration phase with alkaline (AEL) or proton exchange membrane (PEM) electrolysers or other Electrolysis



Source: IEA Hydrogen Production Projects Database

The production of renewable hydrogen is expected to continue increasing if alkaline, proton exchange membrane and other electrolysis projects announced as "dedicated renewable" become operational by 2030, as summarized in Figure 8. Specifically, if all these planned projects materialise, the renewable hydrogen production in the CESEC region will experience more than a 1000-fold increase, reaching 30.9 TWh by 2030. The anticipated end uses of the renewable hydrogen expected to be produced by 2030 differ from current applications. The primary expected use is in the transport sector (10 projects), followed by projects in the refining sector (8) and in the power generation sector (4 projects). Additionally, one project in the iron and steel is reported. Furthermore, 3 projects aim to inject the produced renewable hydrogen in the gas network.

Figure 8 Expected renewable hydrogen production by 2030 based on alkaline, proton exchange membrane and Other Electrolysis projects expected to be operational by 2030 in addition to the demo and operational projects in 2023.



Source: IEA Hydrogen Production Projects Database

3.1.2 Biomethane

As outlined in the European Commission's Biomethane country fiches[88] in 2021, total biomethane production in the EU27 was 3.5 bcm, i.e., 20% higher than the year earlier. In the long term, biomethane has a potential to cover 35-62% of the declining European gas demand of 271 bcm by 2050[89]. REPowerEU identifies biomethane as the short and medium-term measure to reduce natural gas imports, aiming to boost biomethane production to 35 bcm by 2030.

The CESEC region is also active in the production of biomethane, yet in a very limited number of countries as shown in Figure 9. The highest production takes place in Italy (i.e., 2.25 TWh or 210 mcm), followed by a much lower production in Austria with 27 and 16 operational plants in each country, respectively. Hungary is reported to have 2 biomethane production plants and 1 bioCNG plant[90] but no publicly available data regarding the production is found. Ukraine also hosts a biomethane plant (formerly biogas plant) in the country since 2023 with installed capacity of 3 mcm biomethane (i.e., 0.03 TWh)[91]. It also has a second plant in the Vinnytsia region, where produced biomethane is liquified for further use in the transport sector. In addition, the country has 2 more biomethane plants underway.

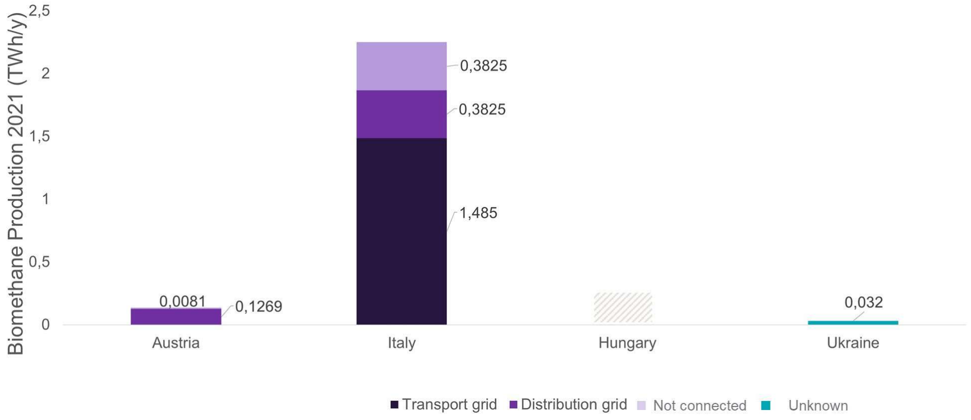
In Italy, most biomethane is consumed in road transport, facilitated by a relatively large CNG car fleet, as well as in Austria via 4 public bioCNG fuelling stations. No end-use information is available for Hungary.

[88] 2023 biomethane country fiches (19 Sept 2023) https://energy.ec.europa.eu/publications/2023-biomethane-country-fiches_en
[89] Biomethane Industrial Partnership (2023) Factsheet Biomethane
[90] European Biomethane Map - Gas Infrastructure EuropeGas Infrastructure Europe (gie.eu)
[91] Prospects of biomethane in Ukraine, UABIO, September 2023; Calorific value of biomethane at 10.61 kWh/m3

In general, the biomethane plant size in those three countries in the CESEC region varies, e.g., plant size capacity in Italy and Hungary is large (i.e., >1000 m^3/h), whereas in Austria small (i.e.,50-250 m^3/h)[92].

Publicly available data of biomethane production in the rest of the CESEC region, i.e., Albania, Serbia, Kosovo, Bosnia and Herzegovina, North Macedonia, Montenegro, and Moldova, are not available. Although these countries lack biomethane production records, some report biogas production, which is a precursor of biomethane. More specifically, Bulgaria, Croatia, Greece, Romania, and Slovenia predominantly produce biogas for electricity generation alone or coupled with heat production in combined heat and power (CHP) plants[93]. Biogas production in the region is supported by existing financial incentives such as Feed-in Tariff (FiT), Feed-in Premium (FiP) mechanisms, and CAPEX subsidies, whereas financial incentives specifically for biomethane are absent. Exceptions are Austria and Italy. More specifically, Italy adopted the FiP mechanism to bridge the difference between the biomethane production cost and the price of natural gas including Guarantees of Origins (GoO)[94], whereas Austria has conceptualised measures to convert electricity-producing biogas plants towards biomethane plants feeding into the Austrian gas grid, as well as measures to establish new biomethane plants[95]. Those measures are subject to political discussions and have not been introduced yet. Among the CESEC countries, only Austria has developed a renewable gas registry[96], whereas Slovenia is in the process of developing its own.

Figure 9 Biomethane production (2021 data). Hungary data refer to 2024.



Source: EBA Statistical Report 2022 Tracking biogas and biomethane deployment across Europe; GIE Biomethane Map 2022-2023; Prospects of biomethane in Ukraine, UABIO, September 2023

[92] Market state and trends in renewable and low-carbon gases in Europe, A Gas for Climate Report, December 2023
[93] 2023 biomethane country fiches - European Commission (europa.eu)
[94] A vision on how to accelerate biomethane project development, BIP Europe, October 2023
[95] EBA Statistical Report 2022 Tracking biogas and biomethane deployment across Europe
[96] ERGaR - The European Renewable Gas Registry

3.2 Technical and economic potential & costs of production

In this section, the technical and economic potential of the deployment of renewable hydrogen and biomethane is estimated, along with the respective levelised costs of their production per country. The levelised costs represent the price per unit of energy required for the production plant to breakeven over its lifetime, ensuring that income from the energy produced covers the capital investment (CAPEX), operational costs (OPEX), and feedstock or fuel costs. The methodologies used for the calculation of these potentials and the costs of production are elaborated in Section 2.4 and Section 2.5, respectively.

3.2.1 Renewable hydrogen

The techno-economic potential for renewable hydrogen production is calculated based on the methodology presented in Section 2.4 and the results of the analysis are presented in Table 3. As observed, the overall region has a total remaining realisable RES potential after satisfying electricity supply, heating and cooling and transport needs (excluding electrolysis) of approx. 2,600 TWh. The largest theoretical RES potentials are found in Ukraine (approx. 700 TWh), Italy (520 TWh), and Romania (430 TWh), respectively.

Table 3 Remaining realisable techno-economic potential of renewable hydrogen production in the CESEC region for 2030 (in TWh)

Country	PV - utility scale	Wind onshore	Wind offshore	Total RES production available for electrolysers	Remaining techno-economic potential for renewable hydrogen production[97]
Albania	7.60	6.56	4.06	**18.2**	**12.4**
Austria	5.43	39.81	0.00	**45.2**	**30.7**
Bosnia and Herzegovina	16.81	59.11	0.00	**75.9**	**51.6**
Bulgaria	39.60	74.55	5.02	**119.2**	**81.1**
Croatia	6.38	20.45	11.54	**38.4**	**26.1**
Greece	47.33	39.74	60.01	**147.1**	**100.0**
Hungary	33.27	191.07	0.00	**224.3**	**152.5**
Italy	110.95	353.58	57.64	**522.2**	**355.1**
Kosovo	4.45	8.07	0.00	**12.5**	**8.5**
Moldova	24.11	24.22	0.00	**48.3**	**32.8**
Montenegro	2.08	28.02	1.47	**31.6**	**21.5**
North Macedonia	9.04	10.55	0.00	**19.6**	**13.3**
Romania	114.34	303.47	9.12	**426.9**	**290.3**
Serbia	39.39	143.90	0.00	**183.3**	**124.6**
Slovenia	3.50	9.02	0.11	**12.6**	**8.6**
Ukraine	345.12	336.23	16.65	**698.0**	**474.6**
Subtotal	**809.41**	**1,648.36**	**165.62**		
Total		**2,623.38**			

[97] Assuming 68% electrolyser capacity

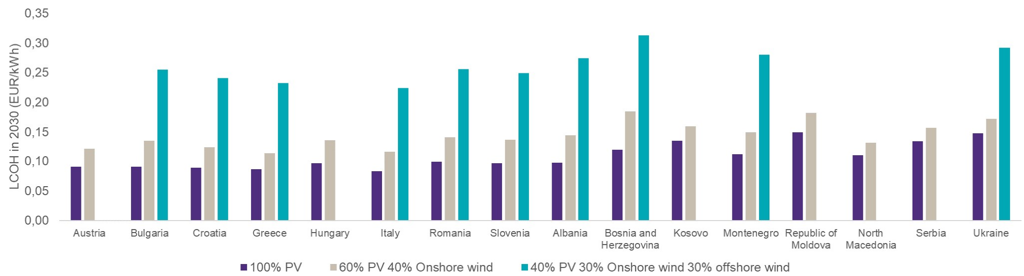
The methodology for the LCOH has been presented in Section 2.5. A key finding of the LCOH analysis is that electricity costs constitute the largest cost for all the countries and range from 69% to 78% of the total LCOH. This highlights the sensitivity of LCOH to variations in assumed electricity prices. The renewable energy potential in each country is composed of different technologies, with each one having a different cost (represented by a different Levelised Cost of Electricity). Thus, an electrolyser plant can be supplied by RES mix comprising typically PV, onshore and offshore. In this analysis, a utility scale electrolyser of 100 MW has been modelled, considering three different RES supply mixes, as illustrated below:

- **Scenario A:** Utility scale electrolyser with 100 MW installed capacity and its total electricity needs are supplied by 60% PV and 40% onshore wind energy.
- **Scenario B:** Utility scale electrolyser with 100 MW installed capacity and its total electricity needs are supplied by 40% PV, 30% onshore wind energy and 30% onshore wind energy.
- **Scenario C:** Utility scale electrolyser with 100 MW installed capacity and its total electricity needs are supplied by 100% PV.

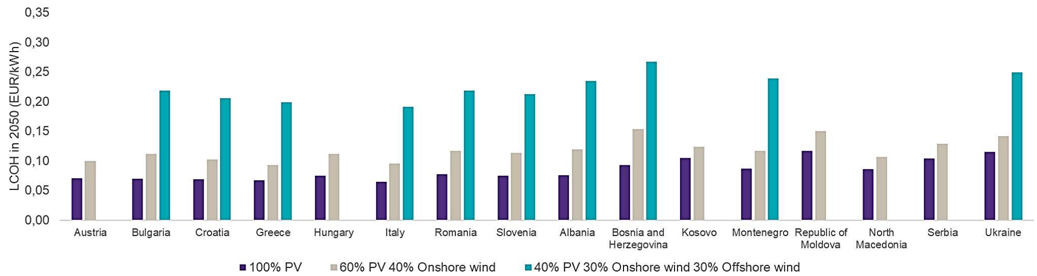
The results of the LCOH analysis for 2030 and 2045 are shown in Figure 10. For any country in the CESEC region, the LCOH is always the cheapest when electricity is sourced exclusively from solar PV plants and gradually increases when the RES mix includes more expensive onshore wind electricity. Similarly, the LCOH is highest when the RES mix includes expensive offshore wind installations. Furthermore, the LCOH decreases from 2030 to 2045 across all assumed RES mixes electrolyser sizes. The latter is the consequence of technology advancements, in both RES and electrolysis, leading to reduced capital expenditures and improved values for renewables.

Figure 10 Levelised cost of renewable hydrogen in (A) 2030 and (B) 2050 as produced by a 100 MW electrolyser in EUR/kWh as per scenarios A, B and C. For countries with no offshore wind potential, scenario C is not presented

A



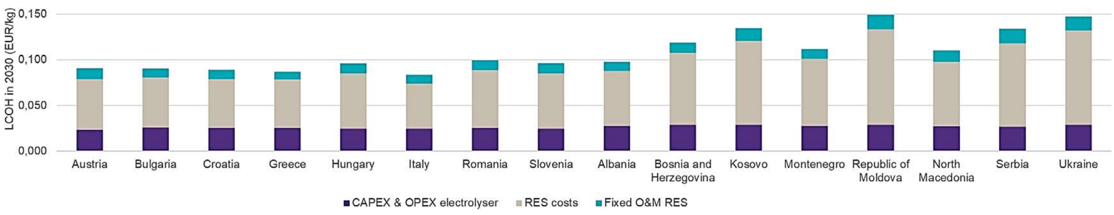
B



Source: own elaboration

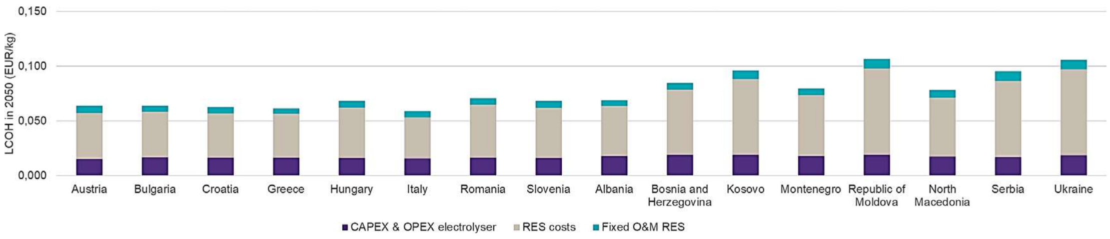
Finally, Figure 11 illustrates the breakdown of the LCOH in the following cost items: CAPEX and OPEX of the electrolyser, renewable electricity costs and operation and maintenance (O&M) for renewable generation plant. The electrolyser is assumed to be 100 MW solely supplied by PVs. It can be concluded that the renewable electricity costs could be up to 70% the total LCOH. Figure 12 shows expected LCOH in 2050.

Figure 11 Levelised cost of renewable hydrogen in 2030 for the CESEC region as produced by a 100 MW electrolyser in EUR/kWh assuming 100% PV supply, optimum sizing of RES vs electrolyser



Source: own elaboration

Figure 12 Levelised cost of renewable hydrogen in 2050 for the CESEC region as produced by a 100 MW electrolyser in EUR/kWh assuming 100% PV supply, optimum sizing of RES vs electrolyser



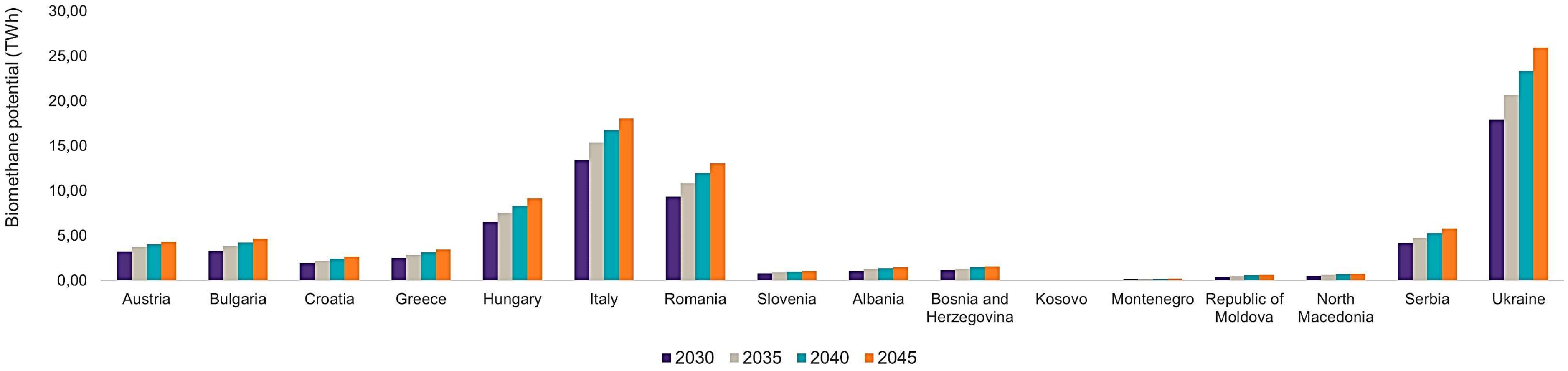
Source: own elaboration

3.2.2 Biomethane

The most commonly used biomethane production technology is anaerobic digestion, whereas the most common upgrading technique is membrane separation. Other biomethane production methods, such as thermal and hydrothermal gasification show high potential, but are only in an early commercial stage and industrial demonstration stage, respectively[98]. The current study considers three different types of feedstocks for the production of biomethane, i.e., agricultural residues (barley, maize, oat, rye, wheat), manure (cattle, cows, chickens, goats, sheep, pigs) and biowaste (animal and mixed food waste, vegetable waste). Figure 13 summarises the sustainable biomethane potential in each of the countries in the CESEC region, as calculated following the methodology presented in Section 2.4.

98 Gas-for-Climate-Gas-Decarbonisation-Pathways-2020-2050.pdf (consorziobiogas.it)

Figure 13 Sustainable biomethane potential (in TWh) based on agricultural residues, animal manure and biowastes in the CESEC region. Kosovo is not included due to absence of statistical data on biomethane feedstock



Source: own elaboration

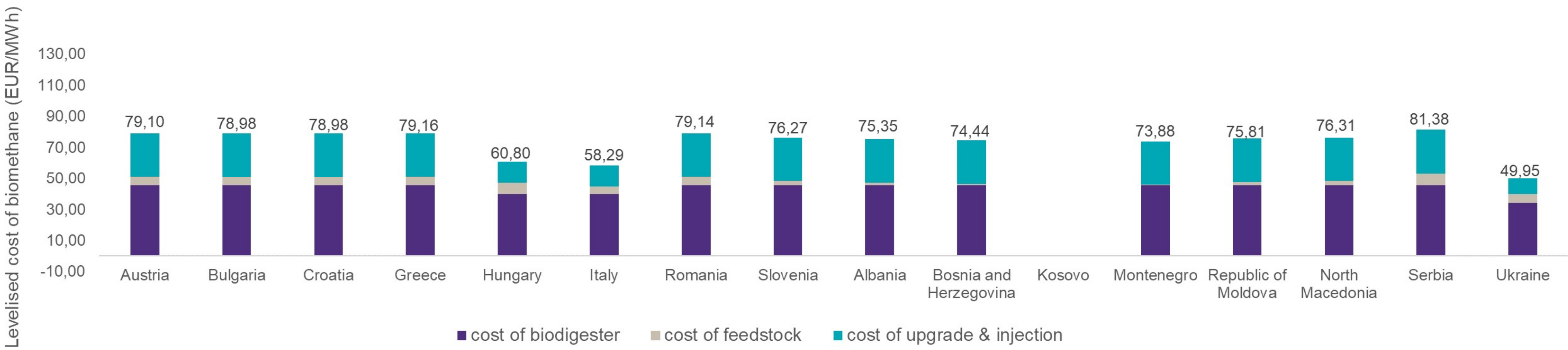
Among all countries studied, Ukraine exhibits the highest potential in biomethane as a result of both significant quantities in agricultural residues and in animal manure. Specifically, Ukraine has the highest number of crops and the second highest number of livestock following Italy. Within the EU Member States in the CESEC region, Italy and Romania demonstrate the highest biomethane potentials. Biomethane potential data for Kosovo cannot be calculated due to absence of statistical data on crops and on livestock. Although biowaste in Kosovo is reported in the EUROSTAT database, absence of population growth data does not allow for projections of biowaste, thus the biomethane potential based on biowaste cannot be computed either. Montenegro exhibits the lowest biomethane potential out of all countries as a result of very low quantities in agricultural waste and in animal manure.

To calculate the LCOB, the approach presented in Section 2.5 is employed. As clearly shown in Figure 14, LCOB ranges between 50 and 82 EUR/MWh. Ukraine appears to be able to produce the least expensive biomethane in the region, whereas biomethane production in Serbia costs the most. The main difference between these countries is attributed to the economies of scale benefiting the production in Ukraine (i.e., large production plants assumed in Ukraine and small ones in Serbia). Weighted average feedstock cost also differs from one country to another both as a result of differences in the feedstock cost, as well as due to a different feedstock mix. As discussed earlier, the biomethane potential in Kosovo cannot be computed and, thus, neither can the respective LCOB.

The observed LCOB range is attributed to variations in the feedstock type and in the size of plant from country to country. Specifically, variations in the feedstock type yield different feedstock costs due to the fact that, among feedstock types studied, only agricultural residues have roadside costs, while the feedstock cost of animal manure and biowaste only entails transportation costs from the source of the feedstock to the process plant. As noted also in the ENGIE report[99], most of the time, farmers give manure for free to the conversion plant in exchange for digestate used as fertilizer. Variations in the size of plant translate into economies of scale both for the biodigesters and the upgrade and injection parts.

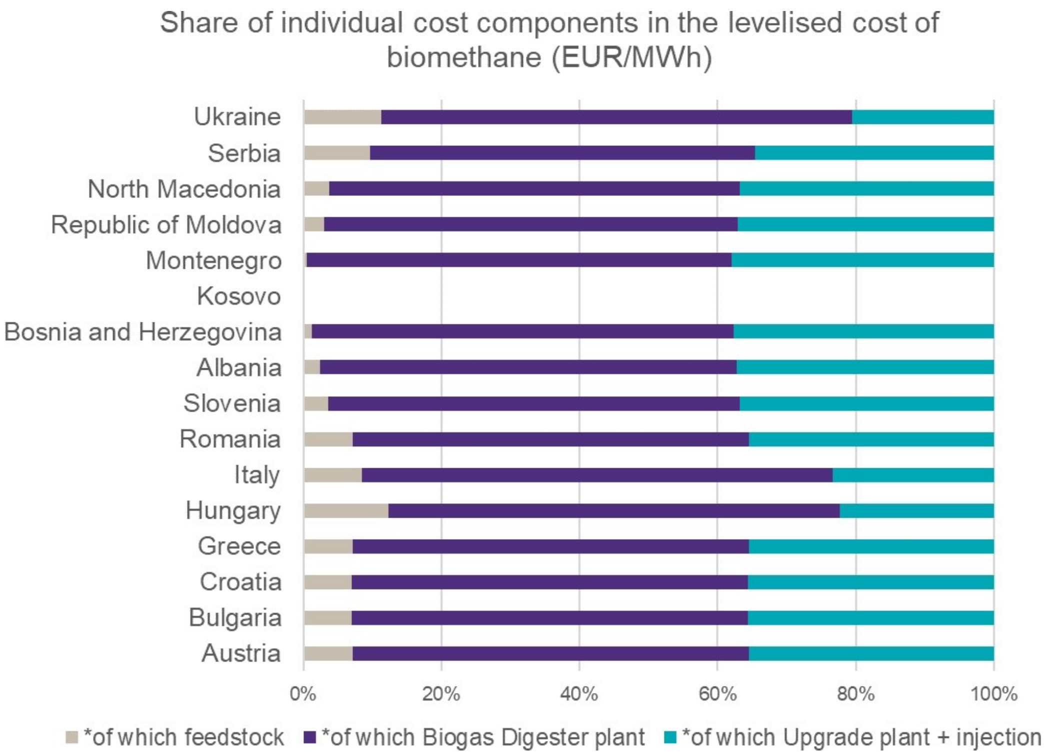
[99] Microsoft Word - ENGIE_20210618_Biogas_potential_and_costs_in_2050_report_v5[5].docx

Figure 14 Levelised cost of biomethane production in 2030. Kosovo is not included due to the absence of statistical data



Source: own elaboration

Figure 15 Share of the individual cost components in the levelised cost of biomethane production. Kosovo is not included due to the absence of statistical data



Source: own elaboration

3.3 Policy and regulatory context

To understand the regional context concerning renewable and low-carbon gases, the relevant provisions and targets included in the integrated NECPs and the NHS, if available, are taken into consideration. Another indicator is the hydrogen-dedicated funds included in the RRPs of the EU Member States. As a first step, Table 4 summarises the availability of these documents for each of the studied countries in the CESEC region.

Table 4 Overview of the status regarding NECPs, NHSs and RRPs

Country	Draft updated NECP[100]	NECP	NHS	Revised RRP	RRP
AL		✓			
AT	✓	✓	✓	✓	✓
BA		✓ [101]			
BG	✓	✓		✓	✓

[100] *"By 30 June 2023, EU Member States and members of the Energy Community were due to submit their draft updated NECPs in line with article 14 of the Governance Regulation";*
[101] Recommendations on the preliminary draft are available

Country	Draft updated NECP[100]	NECP	NHS	Revised RRP	RRP
EL	✓	✓		✓	✓
HR	✓	✓	✓	✓	✓
HU	✓	✓	✓	✓	✓
IT	✓	✓	✓	✓	✓
Kosovo*		✓[102]			
MD		✓[103]			
ME		✓[104]			
MK		✓			
RO	✓	✓	✓	✓	✓
RS		✓[105]			
SI	✓	✓		✓	✓
UA		✓			

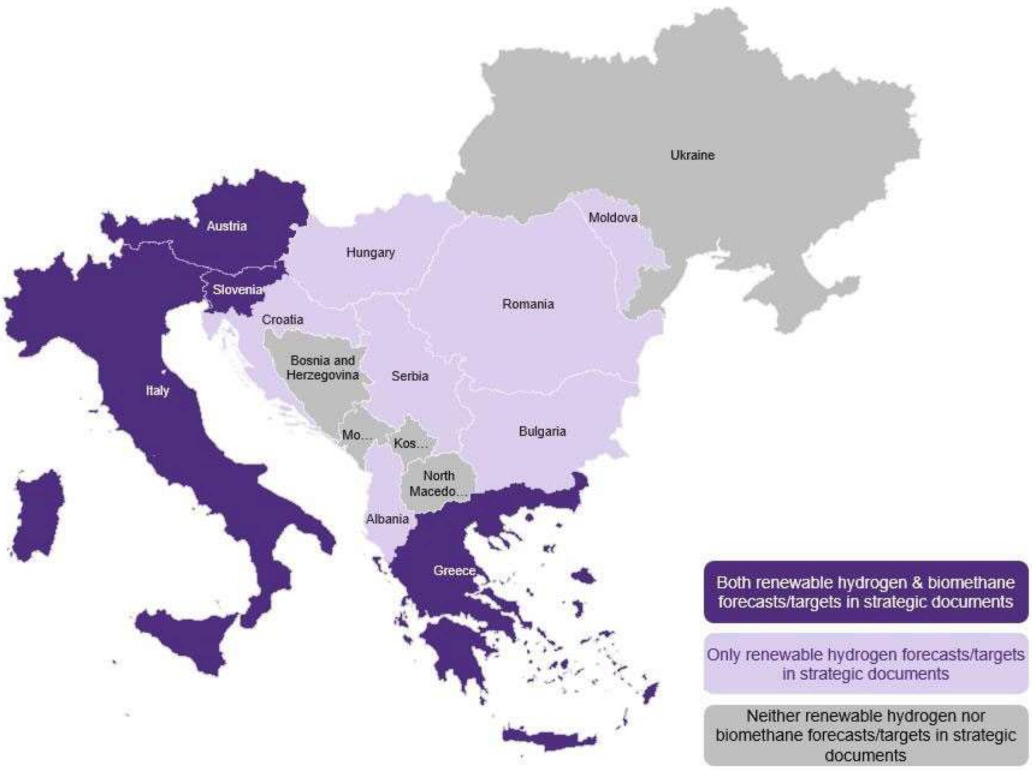
Sources: National energy and climate plans (NECPs) (National energy and climate plans (europa.eu)); Energy Community Homepage (Governance and NECPs - Energy Community Homepage (energy-community.org)); Recovery and Resilience Scoreboard (Recovery and Resilience Scoreboard (europa.eu))

It is noted that all CESEC EU Member States, have submitted their draft updated NECP. In addition, a few countries have published respective NHS documents. All CESEC EU Member States have revised their RRPs to include measures under the REPower EU chapter.

Nevertheless, despite the publication of strategic documents (e.g., NHSs, draft updated NECPs, NECPs, RRP, etc.) in the majority of the countries in the CESEC region, as shown in Table 4, these documents do not always mention specific targets or forecasts linked to renewable hydrogen and biomethane[106]. For example, Bosnia and Herzegovina, Montenegro, Kosovo, and North Macedonia, have no forecasts linked to any of renewable and low-carbon gases in their strategic documents. On the contrary, Albania and Serbia have included specific figures for projected renewable hydrogen end use in transport and industry. Ukraine's national energy strategy developed in 2023 is classified for general public and, therefore, no further elaboration is possible. Figure 16 illustrates the existence or absence of estimates on the production and consumption of renewable hydrogen and biomethane in the strategic documents.

[102] Recommendations on the preliminary draft are available
[103] Recommendations on the preliminary draft are available
[104] Still finalizing its draft NECP
[105] Recommendations on the preliminary draft are available
[106] Data from countries' official strategies and NECPs, compiled by the Consultant

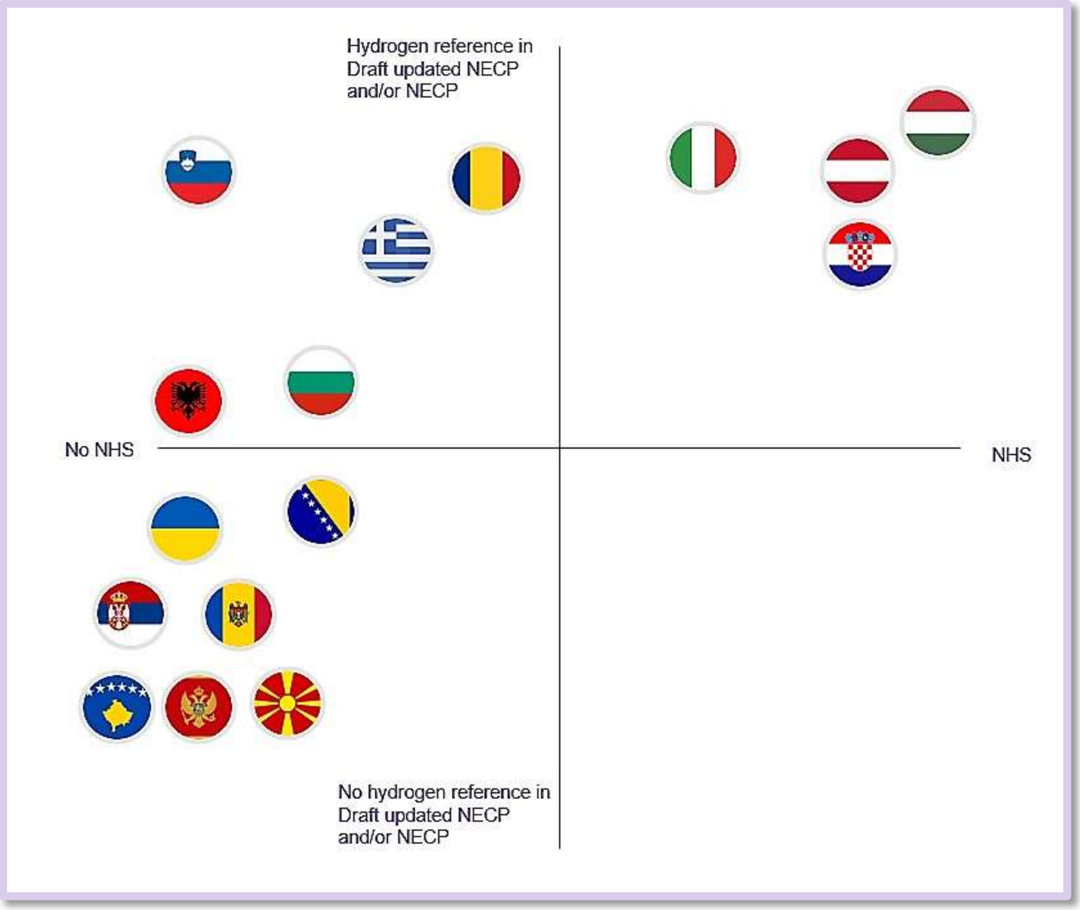
Figure 16 Existence of forecasts/targets on production and consumption of renewable hydrogen and biomethane in the CESEC region



3.3.1 Renewable hydrogen

The existing policy environment regarding renewable hydrogen presents discrepancies among the various CESEC countries that have been assessed. The degree of elaboration ranges from very targeted NECPs and/or NHSs that set clear goals and objectives in certain countries (i.e., upper right quarter of the chart), to very limited or almost non-existent specific policy documents and/or objectives in others (i.e., lower left quarter of the chart), as schematically illustrated in Figure 17.

Figure 17 Illustrative representation of the degree of elaboration of the CESEC countries with regards to hydrogen references in their respective NECPs as well as the existence or not of a NHS[107].



More specifically, **Austria and Croatia** have adopted **elaborate NHSs** to align with their respective NECPs, outlining distinct qualitative and quantitative targets up until 2030 regarding renewable hydrogen production. Austrian NHS also sets a target for renewable hydrogen consumption, aiming to replace 80 % of fossil-based hydrogen consumption with renewable hydrogen by 2030 (energy & non-energy use). The frameworks recognise the need of additional investments in storage infrastructure and transport networks in Austria as the infrastructure will need to take on additional tasks, such as power to gas and storage. The Croatian draft updated NECP[108], submitted in July 2023, provides estimates for the contribution of hydrogen to the gross final consumption up until 2030 and includes specific measures for the deployment of hydrogen (up to 1,273MW of electrolysis capacity by 2030). Similarly, Austria's NHS[109] places special emphasis on the deployment of hydrogen with a set target of 1 GW of electrolysis capacity by 2030. Furthermore, in December 2023, the EU endorsed the updated RRP of Croatia which introduces further measures under REPowerEU to boost the hydrogen economy. The modified plan includes investments in energy network and storage, hydrogen production, storage and distribution pilot projects under the framework of the North Adriatic Hydrogen Valley Project, as well as the purchase of additional 103 hydrogen or electric buses to support sustainable public transport[110].

[107] Figure depicts the status quo in February 2024. It is acknowledged that until the time of the time of publication of the report further developments may have occurred.
[108] Croatia's draft updated NECP (2023)
[109] Austria's National Hydrogen Strategy available here: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwij54GcvMODAxUrgf0HHWkvD7kQFnoECA0QAQ&url=https%3A%2F%2Fwww.bmk.gv.at%2Fdam%2Fjcr%3A7788d724-3aed-4a88-a452- 37f9df5e1357%2Fbmk_wasserstoff_executive-summary_EN_UA.pdf&usg=AOvVaw2g0lHZlRhlMR-RzMtPhkTI&opi=89978449

Hungary's draft updated NECP (2023)[111] aligns with the country's established NHS and its specific targets. Hungary plans to diversify its energy supply and become an important regional transit country for hydrogen transmission in the future. To achieve this, it recognises the need to invest in strategies and measures that further develop human resource skills for the energy transition, particularly in the field of safe management of hydrogen. Hungary's NHS[112], adopted in May 2021, focuses on renewable hydrogen production based on electricity generated from renewable resources, as well as nuclear and other carbon-free origins. Furthermore, to cost-effectively meet increasing industrial demand for low- carbon hydrogen, the usage of fossil-based hydrogen with abatement or hydrogen originating from methane pyrolysis is being considered. Hungary's NHS targets 240 MW of electrolyser capacity by 2030.

Greece and Italy have both submitted elaborate draft updated NECPs (2023) that outline qualitative strategies to leverage hydrogen as a low-carbon solution to achieve renewable energy targets by 2030. Greece's draft updated NECP includes a specific quantitative target to produce hydrogen set at 0.92 TWh by 2030. However, Greece's NHS is still pending finalisation. Considering the recent submission of the draft updated NECP (2023), Greece will need to ensure that the forthcoming NHS reflects the targets set herewith. Italy, on the other hand, has already prepared and submitted a preliminary NHS, which will serve as the basis for consultation before the revised hydrogen strategy is released. This preliminary NHS stipulates the creation of hydrogen valleys where production facilities concentrate around demand clusters, reducing electricity and hydrogen transportation. It elaborates on three potential models at low- cost, i.e., on-site production and consumption, on-site production with energy transport and renewable electricity, and centralised production with transport of hydrogen. The preliminary NHS foresees phased applications of hydrogen, i.e., by 2030 it is expected to be used in transport and industry and, in segments where hydrogen is already used as a raw material (e.g., chemicals and oil refining, steel, cement and glass production). By 2050, end-use sectors could expand to include commercial and residential heating applications, maritime transport and aviation, storage, and generation of electricity from hydrogen due to progressive sector coupling between electricity and gas systems.

Among the remaining EU CESEC countries, **neither Romania nor Slovenia have yet formulated an NHS.** While Romania is currently working on the development of an NHS, Slovenia does not intend to adopt an NHS. Instead, extensive provisions on a regulatory basis have been included in Slovenia's draft updated NECP (2023)[113] which recognises that hydrogen and other renewable gases will play a crucial role in integrating the production of renewable electricity, as they can be used to store large amounts of electricity produced during periods of low demand. Furthermore, the updated Plan envisions the establishment of a dedicated hydrogen system that allows for the transfer and refuelling of renewable hydrogen. This includes preventive replacement of older equipment, installation of additional equipment to track gas composition, and upgrading of compressor stations. Moreover, the Slovenian draft updated NECP (2023) neither sets specific objectives or targets for the production or use of hydrogen, nor mentions hydrogen specific policies and measures. Romania's draft updated NECP (2023)[114] considers hydrogen deployment mainly in the transport, gas and power sectors without, however, setting any specific targets or objectives. Furthermore, Romania has recently passed laws that mandate industrial hydrogen users to meet 50% of their demand with low-emission hydrogen by 2030 and transport fuel suppliers to meet 5% of their fuel sales with renewable hydrogen-based fuels by 2030[115]. Nuclear energy is also considered for the production of hydrogen.

110 SWD_2023_380_1_EN_autre_document_travail_service_part1_v4.pdf (europa.eu)
111 Updated draft of the National Energy and Climate Plan of Hungary 2021-2030 (Sept. 2023). Available at: https://commission.europa.eu/system/files/2023-09/HUNGARY%20-%20DRAFT%20UPDATED%20NECP%202021-2030%20_EN.pdf
112 National Hydrogen Strategy of Hungary, 2021 available here: link
113 Updated draft of the National Energy and Climate Plan of Slovenia 2021-2030 (July 2021). Available at: https://commission.europa.eu/publications/slovenia-draft-updated-necp-2021-2030_en
114 Updated draft of the National Energy and Climate Plan of Slovenia 2021-2030 (July 2021). Available at: https://commission.europa.eu/publications/romania-draft-updated-necp-2021-2030_en

Countries such as **Albania** and **Bulgaria** have set preliminary targets for renewable energy sources like biofuel and hydrogen within their draft NECP (2021)[116] and initial NECP (2019)[117], respectively, primarily focusing on the transport sector. While neither country has prepared an **NHS**, the Bulgarian RRP supports the development of a National Hydrogen Roadmap aimed at stimulating hydrogen technology growth, meeting climate targets, reducing emissions, championing renewables, and advancing towards a more circular economy. Furthermore, as part of the REPowerEU plan, establishing a comprehensive hydrogen network has become a priority, with Bulgaria joining the Southeast corridor alongside Greece and Romania[118].

Similarly, Moldova's Integrated NECP[119] includes references to hydrogen in the framework of renewable energy usage in the transport sector. In this respect, it makes projections for 0.03 ktoe annual consumption of hydrogen starting in 2035.

Kosovo, Montenegro and North Macedonia show no progress in renewable and low-carbon gases, with no strategic plans, laws and regulations referencing hydrogen. The draft NECP of Montenegro (2018) should serve as a major document for future prioritisation of energy transition and decarbonisation, but it is still under finalisation. In North Macedonia, certain initial discussions on hydrogen deployment have been held at a high-level and mainly due to the forthcoming construction of the natural gas transmission and distribution systems in the country.

Recently, **Serbia** presented a preliminary plan for integrating renewables in its energy mix along with some target-setting within its draft NECP (2023)[120]. Similarly, preliminary target setting is also implemented in the draft Hydrogen Strategy of Serbia (2022), which expects the use of at least 1% of total electricity production in Serbia by 2035 and at least 4% by 2050 for the production of renewable hydrogen. The draft NHS is not officially adopted, though. The recently released draft NECP (2023)[121] for Bosnia and Herzegovina sets preliminary targets for use of renewable hydrogen in the transport sector (i.e., 1.60 ktoe for cars and 0.04 ktoe for buses). In addition, the industry aims to reduce the role of natural gas, but concrete details and measurable planning are not yet in place.

Ukraine has committed to developing a draft NECP, which was finalised during the report drafting stage. However, the country has recently (January 2024) presented a draft Ukrainian Hydrogen Strategy funded by the EBRD[122]. The draft Strategy was developed with input from market participants and scientific institutions and presents a roadmap for achieving strategic goals along with an action plan. The first draft of the Hydrogen Roadmap for production and use of hydrogen was released in February 2021 serving as a precursor to a full-fledged Hydrogen Strategy and contains analyses of best international practices, potential for renewable hydrogen production and hydrogen usage, production methods and their cost- effectiveness. The roadmap also analyses existing and required infrastructure for hydrogen storage and transportation both for domestic use and export opportunities[123].

Visual representation of renewable hydrogen supply and demand data for 2030 and 2050, as communicated in the draft updated NECPs, is shown in Figure 18. In the absence of draft updated NECPs, data provided for

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115 Global Hydrogen Review 2023, International Energy Agency

116 Draft of the National Energy and Climate Plan of the Republic of Albania 2020-2030 (July 2021). Available at: https://qbz.gov.al/eli/vendim/2021/12/29/872/e65f8bdc-9490-4044-a055-32b844495393

117 Final draft of the National Energy and Climate Plan of the Republic of Bulgaria 2021-2030 (2019). Available at: https://energy.ec.europa.eu/system/files/2020-06/bg_final_necp_main_en_0.pdf

118 https://www2.deloitte.com/bg/en/pages/tax/articles/bg-national-hydrogen-roadmap.html

119 Moldova's Integrated National Energy and Climate Plan (draft), December 2023

120 Draft of the National Energy and Climate Plan of Serbia 2021-2030 (June 2023). Available at: https://www.energy-community.org/implementation/package/NECP.html

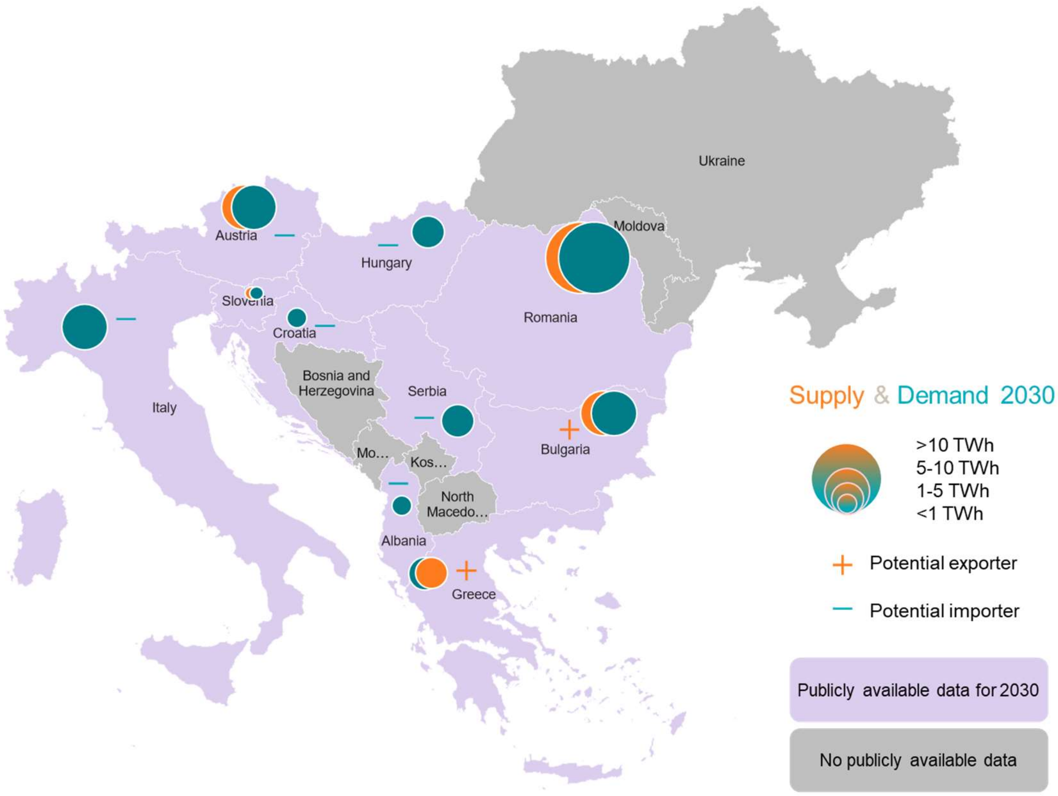
121 Draft of the National Energy and Climate Plan of Bosnia and Herzegovina (June 2023). Available at: https://www.energy-community.org/implementation/package/NECP.html

122 https://www.kmu.gov.ua/en/news/dekarbonizatsiia-ta-zelenyi-kurs-v-minenerho-prezentuvaly-proekt-vodnevoi-stratehii

123 https://unece.org/sites/default/files/2021-03/Hydrogen%20Roadmap%20Draft%20Report_ENG%20March%202021.pdf

the PCI/PMI process by the Member States has been used[124]. It is noted that in the case of Hungary, the draft updated NECP does not communicate a specific number for renewable hydrogen supply by 2030, yet it mentions an installed electrolyser capacity in terms of MW. The actual figures and respective sources used in Figure 18 are reported in Table 5.

Figure 18 Overview of supply and demand patterns in the region in 2030 (upper map) and 2050 (lower map)



[124] PCI/PMI process needs - Regional Groups meeting 20/03/2023

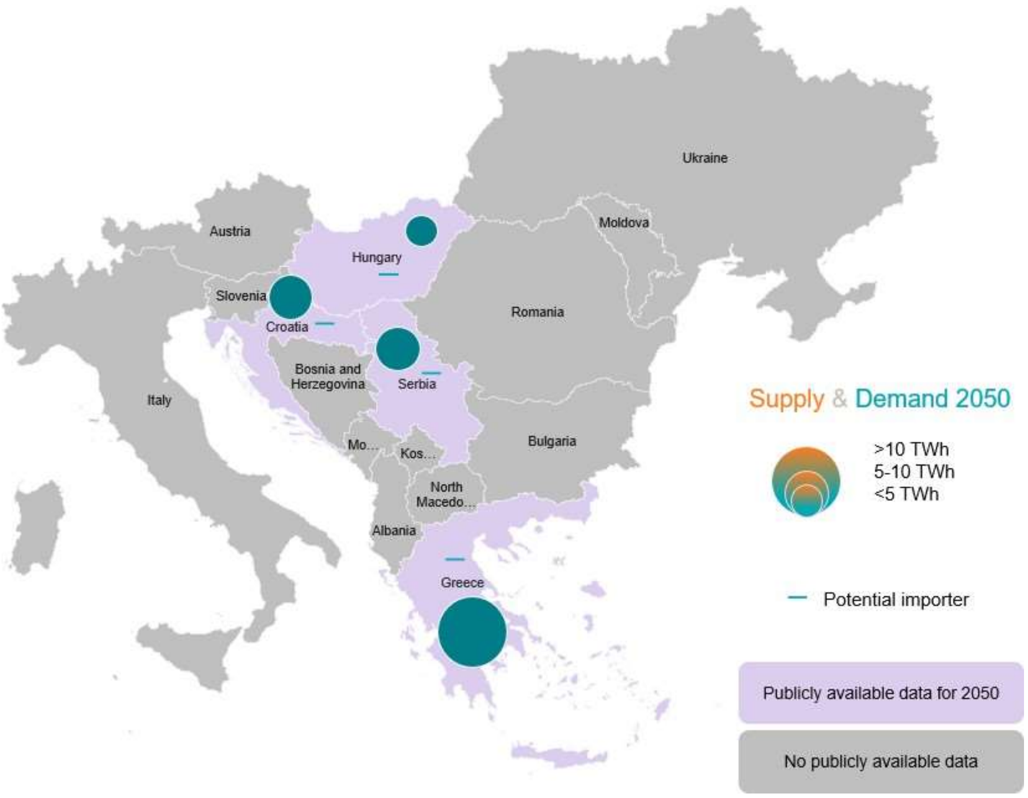


Table 5 Estimated hydrogen production and consumption levels/targets (2030 & 2050)

	Hydrogen in 2030			Hydrogen in 2050		
	Supply (TWh/y)	**Demand (TWh/y)**	**Source**	**Supply (TWh/y)**	**Demand (TWh/y)**	**Source**
AL	n.a.	0.02	NECP	0.23[125] (Renewable H_2)	0.23[126] (Renewable H_2)	NECP
AT	4.3	4.7-11.6	PCI/PMI process needs[127]	n.a.	59.5-92.2[128]	Hydrogen Strategy
BA	n.a.	n.a.	-	n.a	n.a	-
BG	6.6	4.5[129]	PCI/PMI process needs	n.a.	13.2 TWh[130]	ICIS/market assessment
EL	5.32	4.40	Draft NECP	90.65 (Renewable H_2)	63.6 (Renewable H_2)	Draft NECP
HR	1.3	0.46	Draft NECP	6.8-8.8 (Renewable H_2)	8.4-11.5 (Renewable H_2)	Hydrogen Strategy
HU	0.86	1.7	Draft NECP	n.a.	4.00	Draft NECP

[125] 2040 forecast
[126] 2040 forecast
[127] Based on complementary data/information by AT in the context of PCI/PMI process (29/3/2023)
[128] 2040 forecast, lower end used in the modeling exercise
[129] Assuming all hydrogen demand is supplied through renewable hydrogen
[130] Bulgaria launches demand assessment survey for hydrogen transmission capacity | ICIS

	Hydrogen in 2030			Hydrogen in 2050		
	Supply (TWh/y)	Demand (TWh/y)	Source	Supply (TWh/y)	Demand (TWh/y)	Source
IT	n.a.	8.35	Draft NECP	n.a.	20% of energy penetration in final energy demand	Hydrogen Strategy
MD	n.a.	n.a.	-	n.a.	n.a.	-
ME	n.a.	n.a.	-	n.a	n.a.	-
MK	n.a.	n.a.	-	n.a.	n.a.	-
RO	13.2	13.2	PCI/PMI process needs	n.a.	2040: 37.0 TWh 2050: 43.3 TWh[131]	Draft Updated NECP
RS	n.a.	1.1	Draft NECP	n.a.	6.1	Draft NECP
SI	0.40	0.40	Draft NECP	1.95[132]	1.95	Draft NECP
UA	21	10,5	External study[133]	n.a.	50 TWh	Team assumptions
XK	n.a.	n.a.	-	n.a.	n.a.	-

According to Figure 18, the overall demand in the CESEC region by 2030 exceeds the supply by 8 TWh. Among the countries that have communicated demand and supply data for 2030, Greece and Bulgaria expect to have a positive net supply of renewable hydrogen of 0.9 TWh and 3.1 TWh, respectively. Romania and Slovenia project to produce enough renewable hydrogen to meet their own needs, while the remaining countries that have shared data are expected to be importers. As for 2050, scarcity of data in alongside prevailing uncertainty does not allow for a meaningful analysis.

Table 6 summarises the end-use sectors of renewable hydrogen as stipulated in the national strategic documents or communicated by stakeholders via interviews. It is evident that high-intensity industries and the transport sector are prioritised for the uptake of renewable hydrogen. Refineries also represent off- takers of renewable hydrogen. The exception is Albania, where existing refineries are aged and of limited refining capacity. As a result, a large share of crude oil is exported rather than processed within the country.

Table 6 Foreseen end-use sectors of renewable hydrogen

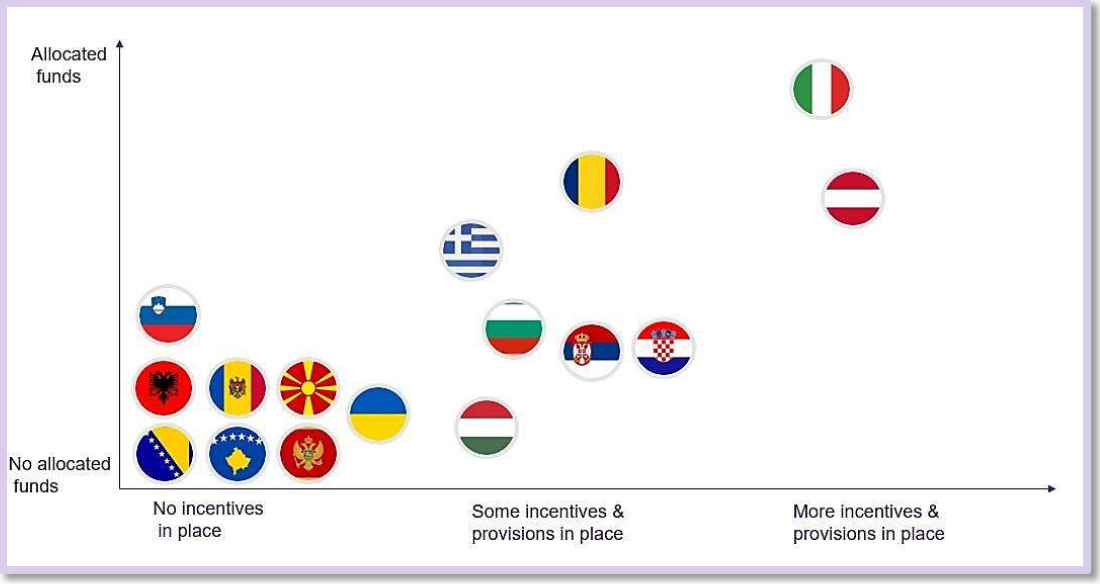
	Refineries	Chemicals production	Industries	Power	Transport	Heating	Source[134]
AL					✓		EnC Report
AT		✓	✓ (steel)		✓		NHS for 2030
BA	*No information provided*						

[131] ROMANIA - DRAFT UPDATED NECP 2021-2030.pdf (europa.eu)
[132] 2040 forecasts
[133] It is assumed by the team that out of the projected 21 TWh of green hydrogen production will be destined for the domestic market in 2030. Source: Green_Hydrogen_in_Ukraine.pdf (energypartnership-ukraine.org)
[134] National energy and climate plans (europa.eu); Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community Part III: Contracting Party assessment ECA, E4tech, June 2021; *

	Refineries	Chemicals production	Industries	Power	Transport	Heating	Source[134]
BG					✓		NECP
EL	✓	✓ (ammonia)	✓ (steel, cement)		✓		Draft updated NECP
HR	✓	✓	✓ (petrochemical)		✓	✓	Draft updated NECP, NHS
HU	✓	✓ (ammonia)	✓ (steel, cement, glass, ceramics)		✓		Draft updated NECP
IT	✓	✓	✓ (paper, steel, ceramics, cement, glass)		✓	✓	Draft updated NECP
MD					✓		EnC Report
ME	*No information provided*						
MK	*No information provided*						
RO	✓	✓ (ammonia)					NECP
RS	✓		✓ (iron, steel, glass, fertilizers)	✓	✓		TSO interview, NECP
SI	✓		✓	✓			Draft NECP
UA	✓			✓	✓	✓	Draft Roadmap for production and use of hydrogen in Ukraine
XK	✓				✓		EnC Report

Regarding the legislative environment concerning hydrogen in the CESEC countries, the focus has been on identifying incentives aimed to promote the hydrogen and low-carbon gases economy. This includes special financing and support schemes, as well as targeted permitting and broader facilitation of project development procedures. Very different patterns have been observed in the degree of adoption of such legislative measures among the studied CESEC countries. Figure 19 illustrates these varying degrees.

Figure 19 Graphic representation of the degree of elaboration of the CESEC countries policies with regards to the available hydrogen incentives and provisions as well as to the relevant allocated funds to promote renewable hydrogen deployment



For **Albania, Bosnia & Herzegovina, Kosovo, Moldova, Montenegro, North Macedonia** and **Slovenia,** renewable hydrogen and the broader low-carbon gases economy are still in its nascent phase. Regarding permitting requirements for hydrogen, the focus primarily lies on its storage, given its classification as a dangerous and flammable gas. **Ukraine** similarly lacks a developed hydrogen-specific legal framework, with no established incentives for the development of hydrogen projects.

The landscape differs in **Serbia, Bulgaria and Croatia**, as these countries have introduced certain preliminary legislative measures to incentivise and facilitate the hydrogen economy through their respective NECPs.

Specifically, **Serbia** has introduced incentives such as a market premium and a feed-in tariff system to promote the establishment and use of innovative technologies and new renewable energy sources such as renewable hydrogen.

In **Bulgaria**, although the regulatory framework for hydrogen is not yet developed, the Bulgarian Energy Act amendment of February 2021 foresees that, unlike other renewable energy sources, all new renewable hydrogen production facilities operational from February 2021 are exempted from paying the 5% fee to the Bulgarian Fund for Security of the Energy System.

More targeted and comprehensive legislative initiatives promoting the development of the hydrogen economy have been established in Romania, Greece, Austria, Italy, and Hungary, aligning with their respective NHSs.

In **Romania**, the Ministry of Energy is developing a state aid scheme aimed at boosting investments in the construction of renewable hydrogen production capacity in electrolysis plants, financed through the country's RRP. Contrary to Romania, **Hungary** has not yet implemented any specific tax incentives or support schemes to promote the utilisation of renewable or low-carbon hydrogen. With respect to the planning and permitting framework however, Hungary has identified all permitting requirements related to production of hydrogen under the Hungarian Law and Administrative Procedures (LAP). It also outlines the legal requirements for hydrogen refuelling stations (HRS) and the permitting process, including the administrative steps required to obtain the necessary approvals to for the construction and operation of a HRS.

Greece is in the process of drafting the regulation fostering the deployment of renewable hydrogen into its market. Simultaneously, Greece has allocated € 75 million towards achieving a cumulative capacity of at least 45MW through the country's updated RRP as of December 2023. Additionally, a fast-track licensing procedure is planned to expedite and enhance hydrogen integration into the Greek system development. The National Regulatory Authority (NRA) will determine the framework for developing and regulating the domestic hydrogen market.

In **Italy**, the 'Green Revolution and Ecological Transition' allocates a total of € 5.56 bn from the country's RRP to hydrogen related projects[135]. The RRP foresees a reform defining safety rules for production, transport, as well as for the storage and use of hydrogen. Additionally, a system of guarantees of origin will be introduced aiming to provide price signals for renewable hydrogen. Regarding permitting procedures required for building and operating a hydrogen production facility, Italy has implemented uniform procedures nationwide. As a result, special decrees govern the creation of alternative fuel infrastructure. Recent legislative developments have introduced certain provisions that helped overcome some barriers as hydrogen was previously considered as an industrial chemical product produced at large scale with fossil fuels and, therefore, subject to stringent prevention measures for hydrogen storage.

Among the CESEC countries**, Austria** has the most comprehensive legislative measures already in place to accelerate the hydrogen economy by facilitating development through customised support schemes. Specifically, investment subsidies of up to 45% (excluding land) for electrolysis plants with a minimum capacity of 1 MW are introduced by the Renewable Energy Expansion Act[136]. The Act also introduces an exemption of electrolysis plants from all electricity-related end-user fees and levies to accelerate the market ramp-up of decarbonising processes. Also, connection costs of renewable hydrogen generation plants are born by the network operators. Austria plans to create favourable conditions for injecting renewable hydrogen into the existing natural gas infrastructure. This includes supporting the uptake of renewable hydrogen through more favourable taxation, set at 0.021 €/m^3 for renewable hydrogen. Regarding national financial instruments, the Austrian RRP contains financial support amounting to 125 million euros for hydrogen-related Important Projects of Common European Interest (IPCEI). As for the licensing obligations of renewable hydrogen production plants, provisions of the Austrian Industry Act apply requiring among others environmental impact assessments for plants producing more than 150,000 tonnes per year of renewable hydrogen[137].

3.3.2 Biomethane

Results from the performed study indicate that the available policy environment for biomethane in the CESEC countries is less defined than that for renewable hydrogen. For most of the countries assessed (**Albania, Bosnia and Herzegovina, Bulgaria, Kosovo, Moldova, Montenegro, North Macedonia, Romania, Serbia**), there are neither strategic targets nor policies to promote the use of biomethane.

On the other hand, **Italy and Austria** have made the most significant legislative advancements towards facilitating biomethane uptake.

The **Italian** draft updated NECP (2023) promotes the upgrade of biogas plants to biomethane plants, to meet the needs of the energy transition. Furthermore, on 15 September 2022, pursuant to Investment 1.41 of the Italian Recovery and Resilience Plan (the "PNRR"), the Minister of Ecological Transition signed the new decree which defines a regulatory framework for incentive measures aimed at the development of production plants for biomethane fed into the natural gas grid providing (i) a capital contribution of 40 % on the eligible costs of the incurred investment and (ii) a specific feed-in tariff (the "New Biomethane Decree",

135 https://www.italiadomani.gov.it/content/sogei-ng/it/en/Interventi/investimenti/idrogeno.html
136 Austrian_Renewable_Energy_Expansion_Act_1645214803.pdf (pvaustria.at)
137 Hydrogen law and regulation in Austria | CMS Expert Guides

199/2021)[138].Furthermore, the Italian RRP earmarks funds with a vision to attain a production threshold of 4 bcm of biomethane by 2026 and 5.8 bcm by 2030 (equivalent to approx. 60 TWh[139]).

Austria's NHS supports the development of incentives for biomethane production and streamlining licensing and permitting processes[140]. The strategy also contemplates the implementation of a renewable gas sales quota within the Austrian gas market. More specifically, the Renewable Energy Expansion Act (EAG 2021)[141] introduces investment subsidies in the amount of 80 million euros per year for both electrolysis and biomethane plants feeding biomethane into the gas network but also for conversion of electricity generating plants into biomethane injection plants. Investments are subsidised with up to 45 % of the investment volume directly required for the construction of the plant (excluding land) and connection costs of biomethane plants borne by the network operators. Another measure included in the Renewable Expansion Act, aimed to further contribute to the uptake of biomethane, is a restriction stipulating that biogas-fuelled plants with maximum capacities of 250 kWel and located less than 10 km away from the gas grid are eligible for a single extension of the Feed-in Premium (FiP) support for only up to 24 months instead of 30 years. This restriction implies that large biogas plants located close to the gas grid are disincentivised to produce electricity and, instead, could opt for producing biomethane. The rest of the CESEC countries (i.e., Croatia, Slovenia, Greece, Hungary, Italy, Austria, Ukraine) seem to gradually acknowledge and integrate biomethane in their strategic documents especially in the more recent revised versions of them. The degree of integration and target setting for biomethane capacities stipulated in the plans varies significantly among these countries.

Croatia and Slovenia explicitly have indicated biomethane in their NECPs with plans for injecting biomethane into the gas network, the establishment of a certification system for biomethane, as well as introduction of measures aiming to develop the market for low-carbon fuels in the transport sector. In this context, Slovenia sets a target of 2.2 TWh of biomethane production for 2030.

Greece has incorporated biomethane production targets (i.e., 2.1 TWh by 2030 and up to 9.7 TWh by 2050) within its draft updated NECP (2023). The Plan also includes significant provisions aimed at using biomethane for decarbonising transport, implementing a Guarantees of Origin (GO) system to stimulate biomethane use and promoting pilot projects to highlight biomethane's role in the energy sector. Similarly, the draft updated NECP of **Hungary** projects that by 2030, biogas and biomethane could account for 1% of the country's natural gas usage. To achieve this, Hungary intends to establish a feed-in system to promote biomethane production and develop a registry for guarantees of origin for biomethane.

Regarding **Ukraine**, while biomethane is mentioned in the national Hydrogen Roadmap and in the national energy strategy, specific measures to facilitate the uptake of biomethane are absent[142]. Ukraine's current Energy Strategy sets a goal of achieving 11 Mtoe of biomass, biofuels, and waste in the total supply of primary energy in 2035. It corresponds to 11.5 % (currently 4%[143]) of the projected total primary energy supply and, hence, biogas and biomethane are expected to play a crucial role in this development.

Visual representation of biomethane supply and demand data for 2030, as communicated in the national strategic documents, is shown in Figure 20. It is evident that very little emphasis is placed on biomethane, considering that only two countries (Italy and Greece) indicate targets for 2030 in their draft updated NECPs. The actual numbers are summarised as part of Annex F: Renewable gases production and consumption levels/targets. It is worth mentioning that countries already producing biomethane, i.e., Austria, Hungary and Ukraine, do not have any targets in the strategic policy documents. Nevertheless, it is likely that there will soon be an updated outlook since EC's recommendation[144] on Hungary's draft updated NECP suggests

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[138] New Biomethane Decree (gop.it)
[139] Assuming GCV of 38MJ/m3
[140] Wasserstoffstrategie für Österreich. Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology, Federal Ministry Labour and Economy (2022).
[141] EBA (2022): SUPPORT SCHEMES FOR BIOGAS AND BIOMETHANE IN AUSTRIA. Available at: https://www.europeanbiogas.eu/wp-content/uploads/2022/04/Support-schemes-for-biogas-and-biomethane-_-AUSTRIA_April2022.pdf
[142] Draft Roadmap for production and use of hydrogen in Ukraine. Ministry of Energy of Ukraine (2021)
[143] https://www.etipbioenergy.eu/images/ETIP_Bioenergy_Factsheet_Ukraine__Update_2021.pdf
[144] Recommendation_draft_updated_NECP_Hungary_2023.pdf (europa.eu)

including further measures promoting the sustainable production of biomethane in the country. In addition, Ukraine only started to produce biomethane at the end of 2023.

Figure 20 Biomethane supply data for 2030

Considering the legislative environment, even fewer countries have established concrete measures to support and facilitate biomethane expansion. **Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Kosovo, Montenegro, North Macedonia, Romania** have not implemented any legislative measures in this regard. **Ukraine** recently (March 2024) adopted Law 9456 on allowing Ukrainian biomethane producers to export the product to European markets and join the relevant European network. The Serbian **Law on the Use of Renewable Energy Sources** (Official Gazette of the RS, no. 40/2021) briefly specifies potential incentives that could be introduced on the production of biofuels to allow the country to reach the planned share of renewables in the final energy consumption in the transport sector. **Moldova** has adopted some general provisions stipulating that any party interested in switching from biogas to biomethane can have access to the gas network provided that they meet the requirements of the natural gas production license, which is issued by the NRA in accordance with the Natural Gas Law. Despite this enabling framework, no entity has so far expressed interest in converting biogas to biomethane[145].

[145] Moldovan Ministry of Energy (2022). Personal communication, 29 December.

As already mentioned in the previous section, a dedicated support scheme for biomethane and hydrogen is envisaged within the **Greece's** RRP allocating cumulatively € 75 million for at least 45MW of combined capacity for renewable hydrogen and biomethane. Similarly, **Hungary** plans to support the production of biomethane through the establishment of new subsidy schemes. However, as of now (at the time of drafting the present report), such measures have not yet been put into place.

3.4 Benefits from the switch to renewable and low-carbon gases

The introduction of renewable and low-carbon gases will yield several benefits for the CESEC countries, including decarbonisation of energy systems, decrease of import dependency, enhancement of energy security and stimulation of economic growth among other considerations. The benefits linked specifically to renewable hydrogen and biomethane are briefly discussed below.

RES hydrogen to serve for displacement of fossil fuels

Based on the available information so far, presented also in section 3.3.1, it is estimated that demand of renewable hydrogen will rise in the following years. Consequently, it is expected that considerable amounts of fossil fuel quantities will be replaced by renewable hydrogen. Considering the NECP targets for 2030 and the data communicated during the PCI/PMI process needs summarized in Table 5 (and relevant assumptions where applicable), it is estimated that renewable hydrogen in the CESEC region (excluding consumption in Germany) can displace approx. annually **54 TWh of natural gas in industry and diesel[146] (for the transport sector) in 2030 and approx. 411 TWh in 2050, assuming that all hydrogen produced is renewable.** No comprehensive analysis for biomethane is available due to the absence of solid policy targets in most of the assessed countries.

Achieving emissions savings

The substitution of fossil fuels from renewable hydrogen and biomethane can play a significant role in the decarbonisation of energy systems and meeting emission reduction targets. For the purposes of the modelling analysis, it has been assumed that renewable hydrogen will displace by 80% natural gas in the industrial sector and by 20% fossil fuels in the transport sector. Relevant total emission savings are estimated to be in 2030 of approx. **8,780,000[147] tCO2e and** approx. **2,900,000 tCO2e due to the decrease of natural gas and diesel use (in the transport sector)[148]**, respectively. Overall, shifting to cleaner energy sources can also improve air quality, reducing the negative impacts of air pollution on public health, which can lead to lower healthcare costs and an overall improvement in the well-being of the population.

Enhancing energy security

Another important key benefit is related to the fact that diversifying the energy mix with renewable hydrogen and biomethane will assist in enhancing energy security and independence from Russian natural gas. By relying less on imported fossil fuels and securing availability of locally produced renewable hydrogen and biomethane, CESEC countries can reduce vulnerability to supply disruptions and geopolitical uncertainties and increase affordability, potentially leading also eventually to stability of energy prices.

Economic growth and employment opportunities

For the deployment and integration of renewable and low-carbon gases to be successfully implemented, it is also required to deploy relevant technologies and infrastructure, such as electrolysers and dedicated RES plants, pipelines or other dedicated means of transportation of such fuels, tanks and storage facilities. The development, manufacturing and maintenance of required technologies, facilities, infrastructures and equipment will attract investments in the regional energy sector and foster the development and

[146] For the sake of simplicity, it has been assumed that renewable hydrogen replaces exclusively diesel fuel as Heavy-Duty Vehicles usually operate with diesel contrary to gasoline or other fuels.

[147] Based on fossil fuel comparator (IPCC, 2006): Emission factor Natural Gas: 56,15 gCO2e/MJ, GHG Emission factor Diesel Oil: 74,35 gCO2e/MJ

[148] Detailed figures are presented in Section 5.3.3.

establishment of niche industries, which will further stimulate economic growth and employment opportunities. Such opportunities will be further increased based on the involvement of agricultural or waste-based feedstocks for biomethane production, which shall enable rural development and improve circular economy. At the same time, such endeavours will encourage technological innovation, with R&D in these areas unlocking advancements in clean energy technologies and driving fuel competitiveness.

Possibility to utilise existing infrastructure

In addition, there is evidence that main transportation gas assets (i.e. pipelines) can be repurposed to support the transportation of renewable hydrogen and biomethane. This is because existing conventional low-pressure natural gas pipelines (up to 4-6 bar), which are typically made of polyethylene, are already capable of handling pure hydrogen, in terms of pipeline material readiness with the readiness of other network components (such as connections, valves, metering equipment, compressors, etc.) being under evaluation) and biomethane flows[149]. Conversely, conventional medium- (above 4-6 bar) and high- pressure steel pipelines, which form today's backbone of existing natural gas transmission and distribution systems, are only suitable for transporting a low percentage of hydrogen blends. Repurposing these types of infrastructures where feasible will enable the economic and rapid deployment of hydrogen-ready networks and the utilisation of existing natural gas assets.

Enabling sector coupling

Until now, the primary focus has been on decarbonising the electricity sector, often referred to as the "coal phase-out". However, transportation and industrial sectors also require decarbonisation, a goal that often cannot be achieved through direct electrification or battery technology alone. Hydrogen, for instance, can play a crucial role in sector coupling as a fuel. It can be used alongside fuel cell technologies in hydrogen-powered vehicles, leveraging the fuel's high energy density to enable long-distance travel, which is a significant advantage over battery-powered alternatives. Additionally, hydrogen can be instrumental in steel production and can replace oil or natural gas in refining processes and the chemical industry. The deployment of such fuels enhances energy efficiency by optimising the interaction between various energy systems and sources.

Allowing for energy system flexibility

The transformation of electricity into renewable gases and vice versa can introduce additional storage and flexibility options in the energy system, thereby reducing the overall cost of decarbonising the pertinent energy system. System integration enhances the flexibility and stability of energy grids. This integration also promotes the optimised utilisation of resources, catalysing large-scale development of renewable energy sources and enabling the conversion of surplus renewable energy into low-carbon gases. Surplus electricity generated from RES that is not utilised to power electrolysers can also be stored in batteries. This storage capability facilitates a temporal shift of consumption, and the flattening of demand peaks, acting as local buffers. These buffers store variable renewable energy near its production site for later local use or injection into the grid during periods of high demand and prices, thereby facilitating the establishment of holistic coupled energy markets in the region. Furthermore, the deployment of renewable and low-carbon gases fosters the development of decentralised energy systems, enhancing resilience and reducing reliance on centralised power sources.

3.5 Key findings

Overall, the CESEC region shows diverse progress in renewable hydrogen and biomethane across all aspects. Specifically:

[149] ready4h2.com/medien/r4h2/pdf/Ready4H2-ED3.pdf

- Relevant data indicate that, currently, national demand for hydrogen is primarily met by fossil-based hydrogen.
- To date, the production of renewable hydrogen in Austria, Hungary, Greece, and Slovenia remains very limited. These countries have predominantly small-scale projects (below 2 MW) that are either operational or in the demonstration phase.
- Several alkaline and proton membrane electrolysis projects are in development, projected to collectively supply approx. 30.9 TWh of renewable hydrogen by 2030, should they materialise. Notably, these projects are predominantly concentrated in a few countries only, namely Greece, Italy, Austria, Romania, and Slovenia.
- Currently, while Italy, Austria, Hungary, Ukraine produce biomethane, only Italy and Hungary operate large-scale biomethane plants (i.e., >1000 m3/h).
- Bulgaria, Croatia, Greece, Romania, and Slovenia have reported biogas production, a precursor of biomethane, driven by financial incentives linked to biogas for power generation.
- Within the CESEC region, only four countries (i.e., Austria, Croatia, Hungary and Italy) have published National Hydrogen Strategies. All EU Member States have submitted their draft updated NECPs, while among the EnC countries, Montenegro and Moldova lacked NECPs entirely during the drafting stage of the present report.
- Italy, Austria, Greece, Hungary, and Croatia have set targets for installed electrolyser capacity by 2030 (i.e., 5 GW, 1 GW, 300 MW, 240 MW and from 70 to 1273 MW, respectively) according to their published strategic documents (i.e., draft updated NECP, NECP, NHS). However, based on current (demo and/or operational) and announced projects (concept and/or feasibility study and/or FID/Construction phase), only Greece appears to be on track to meet its target.
- In the short and medium term, renewable and low-carbon hydrogen is expected to replace fossil-based hydrogen in refineries and chemical industries, especially in Greece, Croatia, Hungary Romania, Albania, Serbia and Ukraine. In the long-term, potential uses include methanol production, synthetic fuels for transport, and coal replacement in iron production, mainly identified in Austria, Hungary, Croatia, Greece, Romania, Serbia and Slovenia.
- The biomethane production potential in the region is significant, especially in Ukraine, due to the high volume of crops generating agricultural residues. The levelised cost of biomethane remains high, generally ranging from 50 to 82 EUR/MWh, necessitating financial incentives to compete with natural gas.
- The remaining techno-economic RES potential for renewable hydrogen in the region by 2030, after meeting electricity supply needs (excluding electrolysers), is estimated at approx. 2,600 TWh. The highest potentials are identified in Ukraine (approx. 700 TWh), Italy (520 TWh), Romania (430 TWh).
- Total emission savings from displacing natural gas by 2030 are estimated at approx. 8,680,000[150] tCO2e and to about 2,880,000 tCO2e from displacing diesel in the transport sector, adding up to 11,550,000 tCO2e in total[151] (excluding displacement in Germany).

[150] Based on fossil fuel comparator (IPCC, 2006): Emission factor Natural Gas: 56,15 gCO2e/MJ, GHG Emission factor Diesel Oil: 74,35 gCO2e/MJ

[151] Detailed figures are presented in Section 5.3.3.

4 Assessing infrastructure readiness for renewable and low-carbon gases

4.1 Introduction

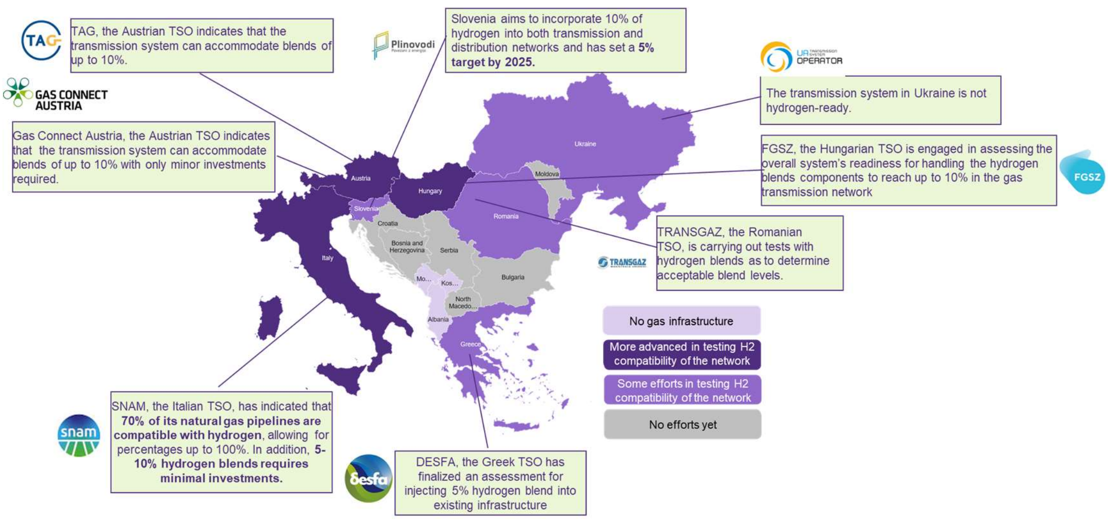
Chapter 4 provides an overview of the infrastructure readiness within the CESEC region to accommodate renewable and low-carbon molecules. It differentiates between the compatibility of the gas networks to accommodate (renewable) hydrogen and biomethane. The analysis is based largely on input from stakeholders gathered through interviews and on information from publicly available reports.

4.2 Hydrogen readiness of infrastructures

The term "hydrogen-readiness" refers to the capability of a transmission system to transport pure hydrogen safely and effectively. That involves ensuring that pipelines and related components are compatible with hydrogen's unique characteristics, such as its high reactivity and potential to cause metal embrittlement. Achieving hydrogen-readiness may also require the implementation of specific operational procedures, including specialised monitoring and maintenance measures, to maintain the security and reliability of the transmission system.

In general, there is a noticeable lack of infrastructure capable of handling pure hydrogen in the CESEC region. This poses a significant challenge for the adoption of hydrogen as a primary energy source. Transmission System Operators and Storage Operators in various CESEC countries have initiated evaluations of their infrastructure components through laboratory testing with regards to their hydrogen-readiness. However, the extent of progress in this area significantly differs among the countries assessed. A qualitative categorisation is undertaken to classify the countries based on their efforts to evaluate the compatibility of their infrastructure with hydrogen. This categorisation is depicted in Figure 21.

Figure 21 CESEC countries grouped by hydrogen infrastructure compatibility progress[152]



As anticipated, there are significant disparities in the availability of gas infrastructure assets among the CESEC countries, as well as in the level of technical, financial, and regulatory progress towards developing the capacity for pure hydrogen transportation.

[152] Qualitative analysis developed by the Consultant, using information collected through stakeholder engagement.

Albania, Montenegro, and Kosovo do not have any gas infrastructure and consequently no gas market has been established there. It is noteworthy that although Trans-Adriatic Pipeline passes through Albania, it does not deliver gas to the country. Preliminary assessments indicate that TAP could potentially accommodate pure hydrogen, but this possibility requires further technical assessment in the future[153]. For these three countries, integrating renewable gases into their energy mix means constructing hydrogen-ready infrastructure from scratch which presents several challenges. Among the most significant challenges are the high costs (i.e., the average repurposing costs of transmission pipelines are expected to be between 10 and 35% of the construction costs for new dedicated hydrogen pipelines[154]) and the long lead times (i.e., 6 to 12 years for natural gas pipelines)[155].

Bulgaria, Croatia, Bosnia and Herzegovina, North Macedonia, Moldova and **Serbia**, despite possessing natural gas infrastructure, have made little progress in assessing their potential for its repurposing in order to achieve pure hydrogen transportation. More specifically, the **Bulgarian** gas TSO reports that no relevant testing, R&D activities or pilot projects are scheduled in near future to assess the network's compatibility with hydrogen[156]. A similar situation is observed in **Bosnia and Herzegovina** and **North Macedonia,** where no assessment or technical analysis of the gas infrastructure readiness for accommodating hydrogen are carried out. The general absence of long-term planning and lack of funding sources create unfavourable conditions for hydrogen deployment in these countries. Particularly in North Macedonia, stakeholders highlight the absence of standards and technical expertise as additional, significant barriers to integrating renewable gasses into their energy mix.

Similar to Bosnia and Herzegovina, **Moldova's** gas transmission system is quite dated and no feasibility studies assessing hydrogen-readiness have been conducted or are planned in the near future. However, in 2020, a partnership between the country's gas TSO and DSO was established aimed at enhancing the regulatory framework to facilitate joint investments for ensuring a safe and accessible supply of energy to both domestic and commercial consumers[157]. It must be noted, however, that the potential for hydrogen supply is limited due to Moldova's current energy supply deficit, which makes it technically and economically unfeasible to produce hydrogen at present.

The landscape in **Serbia** is similar, as no assessment of the transmission network's ability to accommodate blends of hydrogen has been conducted so far[158]. Progress towards hydrogen-readiness is further hindered by the existing gas quality standards which do not allow for the injection of hydrogen into the transmission network. Furthermore, although Serbia has underground depleted gas fields that could potentially be used for hydrogen storage, no assessments or detailed technical studies have been performed yet. However, as per the draft Energy Development Strategy of the Republic of Serbia, the country envisages the construction of a demonstration facility for hydrogen storage by 2030, as well as the need to adopt appropriate gas quality standards that would allow blending hydrogen with natural gas and injecting it into the gas network. Key challenges to hydrogen deployment include financial limitations, insufficient stakeholder engagement and an inadequate legislative framework. Specifically, the natural gas sector in Serbia is not fully aligned with EU Energy Acquis, hindering the complete transposition and implementation of the Network Codes[159]. This regulatory misalignment poses significant obstacles in developing a hydrogen network and supporting the transition to a low-carbon energy system. Having acknowledged those drawbacks, the country foresees in its Integrated National Energy and Climate Plan[160] the development of the legislative framework for the promotion of energy storage technologies, as well as the implementation of demonstration projects for the

[153] TAP (2022). Personal communication, 02 November
[154] https://www.entsog.eu/sites/default/files/2021-05/ENTSOG_GIE_HydrogenEurope_QandA_hydrogen_transport_and_storage_FINAL_0.pdf
[155] Global Hydrogen Review 2023, IEA
[156] Bulgartransgaz (2022). Survey Response, 18 October
[157] Infotag. (2020). Moldovagaz and premier energy agree to develop energy sector in Moldova. Retrieved from http://www.infotag.md/economics-en/283282/
[158] CA E4tech. (2021). Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community. Retrieved from https://www.energy-community.org/news/Energy-Community-News/2021/06/17a.html
[159] Annual Implementation Report Executive Summary Energy Community Secretariat (Nov 2023)
[160] Integrated National Energy and Climate Plan of the Republic of Serbia. Retrieved from https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwirurjG46OGAxVIRPEDHUvW

promotion of biomethane and renewable hydrogen. In **Croatia**, compatibility of the gas infrastructure with hydrogen (either pure or in blends) has not been thoroughly evaluated yet. This applies to both the transmission and distribution networks, as well as to the floating LNG terminal. However, there are indications that certain characteristics of the country's gas network make it much more compatible with hydrogen compared to the previously mentioned countries. Notably, most of the natural gas transmission network is comprised of polyethylene, which could potentially be converted to hydrogen-ready at relatively low cost[161]. Additionally, it is anticipated that hydrogen blends of up to 50% could be accommodated in the transmission and distribution networks without the need for significant adjustments in the regulation stations and measuring equipment. Furthermore, legal and regulatory frameworks allow for injection of hydrogen (either pure or blends) into the gas transmission network as long as it meets the quality standards prescribed in the General rules of the natural gas market. A key obstacle in achieving hydrogen-readiness of the gas networks is the lack of financial resources. This prevents the financing of an in-depth technical analysis and evaluation of infrastructure requirements for repurposing. Moreover, the TSO's ability to secure additional financial resources through revenue increases is limited by national policies that prioritise keeping energy prices low for consumers, thereby compelling the TSO to reduce tariffs.

In contrast to the previous CESEC countries, **Ukraine, Hungary, Greece, Romania, and Slovenia** have begun conducting preliminary assessments for incorporating hydrogen into their energy systems, though these efforts are sporadic and lack clear objectives and targets.

Although the existing natural gas infrastructure **in Ukraine** is not hydrogen-ready, the main gas DSO, RGC, reports on large scale R&D projects focused on hydrogen testing (e.g., hydrogen tightness, stability, effect of mixtures, tests on detectors and gas meters, and tests on appliances). These tests have led to the conclusion that the distribution infrastructure can withstand 20-30% of the hydrogen blend without significant issues. Prior to the outburst of the war, Ukraine had plans to invest in pilot projects to assess the readiness of its gas transmission system for hydrogen transport, both nationally and across the borders with neighbouring countries. Furthermore, in 2020, Ukraine established a technical committee for standardisation called "Hydrogen Technologies", dedicated to working in the field of hydrogen technologies, in compliance with the globally recognised classification of standardisation[162]. Despite these efforts, considerable challenges remain in the country for the planning and integrating of renewable hydrogen into the grid, largely due to the limited financial resources of the gas TSO resulting from the war with Russia. In addition to the economic challenges, the country also faces significant security of supply challenges, which require urgent solutions. On the technical side, a primary challenge is the age of many Ukraine's gas pipelines[163], which could require significant investments in order to make them suitable for hydrogen transmission. Additionally, there are challenges related to gas quality differences, as it is necessary to standardise gas quality requirements at cross-border interconnection points. On the regulatory side[164], the absence of legal regulations on the production and transportation of renewable hydrogen in Ukraine poses a barrier to the development of hydrogen projects, particularly for exporting to the EU via gas pipelines. The Law of Ukraine on the Natural Gas Market does not address hydrogen or its infrastructure. This underscores the need for updated legal frameworks that support the development of the hydrogen infrastructure.

Similarly to the rest of the CESEC region, there are no dedicated networks for hydrogen in **Hungary**. However, in alignment with the country's NHS, several dedicated pilot and R&D projects are underway to evaluate the compatibility of existing equipment and overall system's readiness for handling the hydrogen

BCwQFnoECBMQAQ&url=https%3A%2F%2Fwww.energy-community.org%2Fdam%2Fjcr%3A01992fc5-4981-4ee3-84f8-f1f96830b4ba%2FINECP_Serbia_ENG_13.06.23%2520.pdf&usg=AOvVaw1lA2SI8r3j-5lunwBphthd&opi=89978449

[161] 82.2 % of the total distribution system at the end of 2020 was made of polyethylene pipes, 15.9 % of steel pipes and 1.9 % of other materials

[162] Draft Roadmap for production and use of hydrogen in Ukraine. 2021

[163] Gas Transmission System Operator of Ukraine LLC (2022). Personal Communication. 02 December

[164] Legal regulation of green hydrogen in Ukraine - Sayenko Kharenko (sk.ua)

blends components to reach up to 10% in the gas transmission network[165]. Additionally, FGSZ, a gas TSO, has engaged DNV to conduct an assessment of a DN600 pipeline system for its suitability[166] for hydrogen transport, including the feasibility of transporting up to 100% hydrogen[167]. Finally, further research is also being carried out to explore the potential of using depleted natural gas fields and suitable geological formations for hydrogen storage[168]. Key challenges in planning and developing integration of renewable hydrogen into the grid include the lack of a developed hydrogen market and the uncertainty surrounding the evolution of hydrogen demand in the future[169,170]. Furthermore, the absence of a regulatory framework creates uncertainty for investors and companies looking to enter the hydrogen market, as there are no incentives in place for hydrogen projects. The adoption and implementation of the EU Gas Decarbonisation Package will presumably enhance regulatory development.

DESFA, the **Greek** gas TSO has completed a preliminary assessment of its existing infrastructure for the potential injection of hydrogen blends. The findings indicate that the current infrastructure could accommodate hydrogen blends up to 5%[171] with only minor modifications. However, the feasibility of integrating higher concentrations of hydrogen has not yet been evaluated. On the distribution level, while detailed evaluations assessments for hydrogen injection have not been carried out, the majority of the natural gas network is composed made of polyethylene which suggests that it could be relatively easily and cost-effectively converted to transport pure hydrogen. At the cross-border level, an initial screening study on the Trans-Adriatic Pipeline has identified no major obstacles to transporting pure hydrogen, but this conclusion has yet to be technically confirmed[172] as relevant material laboratory testing is ongoing. Currently there are no actual cross-border flows of renewable gases between Greece and its neighbouring countries. Nevertheless, Greece is actively engaged in the European Hydrogen Backbone and other European initiatives aimed at enabling such flows in the future[173]. In efforts to facilitate cross-border hydrogen transport, DESFA is collaborating with Bulgartransgaz, the Bulgarian TSO, to explore the possibility of establishing a 5% blend across the border and to develop dedicated hydrogen infrastructure. Key challenges to the development of hydrogen infrastructure include the insufficiently developed market for hydrogen and the absence of a regulatory framework for hydrogen production and storage. Additionally, technical limitations currently prevent the injection of hydrogen in the gas transmission due to existing standards that do not allow it.

In **Romania**, the gas TSO, Transgaz, is currently carrying out tests with hydrogen blends to determine the necessary modifications for the transmission network to accommodate hydrogen[174]. Despite these efforts, the maximum hydrogen concentration that can be accepted within the natural gas transmission network has not yet been defined, and the existing gas quality standards do not allow for hydrogen injection into the grid[175]. At the distribution level, there have been no similar assessments conducted yet. As is the case for most of the assessed countries, the main challenges related to the integration of renewable gases and especially hydrogen into the natural gas grid are of economic, regulatory and technical nature[176].

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165 FGSZ (2021), "Future is our duty! – Possibilities of hydrogen transportation studied in joint project by FGSZ and the University of Miskolc", available at https://fgsz.hu/en/home/news/future-is-our-duty-possibilities-of-hydrogen-transportation-studied-in-joint-project- by-fgsz-and-the-university-of-miskolc.html.

166 With respect to the network's volume, the pipeline system, when filled up to full pressure, can cover Hungary's gas demand for one day in the coldest winter

167 https://www.powerengineeringint.com/hydrogen/hungary-assesses-hydrogen-transportation-using-existing-gas-network/

168 FCH 2 JU (2020). Opportunities for Hydrogen Energy Technologies Considering the NECPs. Available at: Final-Report-Hydrogen- in-NECPs-28-8-2020-ID-9474232.pdf (lei.lt)

169 MEKH (2022). Survey Responses. 19 October

170 FGSZ (2022). Personal Communication. 24 November

171 DESFA S.A. (2022). Personal communication, 04 November

172 TAP (2022). Personal communication, 02 November

173 European Hydrogen Backbone, April 2022. Available at: https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf

174 Transgaz (2022). Personal communication, 23 December

175 ACER (2022). Opinion No 08/2022 on the Review of Gas and Hydrogen National Network Development Plans to assess their consistency with the EU Ten-Year Network Development Plan. [online] Available at: https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions%20Annexes/ACER_Opinion_08-2022-Annex_III.pdf

176 Transgaz (2022). Personal communication, 23 December

Slovenia, along with Austria and **Italy** have made considerably more advancements towards implementing hydrogen with Italy being the closest to achieving a completely hydrogen-ready infrastructure network.

In view of Slovenia’s aim (NECP) to incorporate a 10% hydrogen share into the transmission and distribution network by 2030, Plinovodi (gas TSO) is carrying out tests (pilot project at preliminary stage[177]) and has set a target of 5% blending by 2025. Furthermore, all the new transmission infrastructure will be hydrogen-ready although it will initially be used for hydrogen blends due to the current lack of demand for pure hydrogen. On the distribution level, DSOs are part of the Natural Gas Distribution Association (GIZ DZP), tasked - *inter alia* - to implement new gas technologies also for the digitalisation and smartening of the grid. As such, each of the components comprising the national gas distribution system (i.e., steel pipelines, polyethylene pipelines, valves, pressure regulators) should be able to accommodate up to 20% hydrogen blends provided they are constructed, maintained, and operated in accordance with the DVGW technical rules. To further support expansion of the country’s hydrogen economy, Plinovodi is cooperating with adjacent TSOs on issues such as the expansion of capacities on IP, exploring new transit routes, and initiating Projects of Common Interest with some of them. However, Slovenia faces several key challenges in integrating renewable hydrogen into the network, including technical issues related to the compatibility of existing equipment and as well as to gas quality monitoring[178]. Furthermore, the lack of transparency at the national level regarding the future development of hydrogen creates an unfavourable environment for stakeholders.

In **Austria**, the ability of the transmission system to accommodate hydrogen blends up to 10% is verified by technical assessments conducted by TAG and Gas Connect Austria with only minor investments required. The existing pipelines are compatible with pure hydrogen, but more extensive investments in the compressors and other system components are required. However, the existing gas infrastructure is not yet ready to accommodate pure hydrogen and hence relevant examination is deemed necessary. The gas TSO, GCA, is addressing this by implementing a R&D project to assess the compatibility of the transmission network to transport pure hydrogen[179]. As reported, the Austrian TSOs continue replacing relevant components with hydrogen-ready alternatives, thus, gradually improving the network’s overall hydrogen-readiness. According to the study published by the Ready4H2 alliance, 97% of distribution pipelines in Austria are made of materials fully compatible with hydrogen, although the readiness of other components is still under evaluation[180]. When it comes to hydrogen storage, RAG Austria has successfully demonstrated that hydrogen blends up to 20% can be stored in gas reservoirs in a well-tolerated manner (Underground Sun Storage project). Further laboratory tests within the Underground Sun Storage 2030 project aim to explore the potential for increasing hydrogen content. The project will verify whether the hydrogen content can be increased up to 100%[181]. A significant advantage for Austria in terms of hydrogen-readiness is the strong cooperation between the TSOs, DSOs and storage operators. This collaboration is manifested by the research projects: “*ONE100 – Austria’s sustainable energy system – 100 % decarbonised*” and the “*H2 Readiness*”. The latter project is expected to create a roadmap for developing a dedicated hydrogen network to meet future demand and will also evaluate the feasibility of blending hydrogen into the natural gas grid network, including and identifying optimal injection points and sites for electrolysis[182]. Despite these advancements, key stakeholders in Austria have reported common challenges in integrating renewable hydrogen[183]. Currently, the injection of pure hydrogen is not possible, and the gas quality measurement instruments used by TAG are not able to detect hydrogen, necessitating adaptations to the gas measurement systems[184]. At the national level, the absence of specific operating standards for hydrogen grid operation

[177] Personal communication
[178] Plinovodi (2022). Personal Communication. 23 November
[179] GCA (2023). Stakeholder’s Workshop. 1 February
[180] Ready4H2. (2020). Ready4H2: Europe’s Local Hydrogen Networks PART 1: Local gas networks are getting ready to convert. Retrieved from https://www.gruenes-gas.at/assets/Analysen-und-Studien/Ready4H2-ED1.pdf
[181] USP. (n.d.). Project Description. USS 2030. Retrieved from https://www.uss-2030.at/en/project/project-description.html
[182] AGGM. (n.d.). H2 Readiness: AGGM's Plan for the Future of Gas Supply. Retrieved from https://www.aggm.at/en/energy-transition/h2-readiness
[183] GCA, TAG, E-Control
[184] TAG (2022). Personal Communication. 29 November

complicates the approval process for such operations[185]. Additionally, the lack of harmonised gas quality standards across Europe creates significant obstacles.

Italy has made significant progress in adapting its infrastructure to be hydrogen-ready. Around 70% of SNAM's (gas TSO) natural gas pipelines are already compatible with hydrogen[186], with internal regulations for procurement in place to allow for increasing hydrogen percentages up to 100%. SNAM indicates that reaching 5-10% hydrogen blends would require only minimal investments, primarily installation of gas chromatographs and the replacement of a few other minor instrument replacements. SNAM is currently verifying the compatibility of its overall infrastructure with increasing hydrogen blends[187]. From a regulatory perspective, Italy has allowed for a 2% hydrogen blend to be injected into the grid. This limit is designed to safeguard underground storage integrity and ensure end-user acceptance of injected hydrogen[188]. Compatibility of storage with hydrogen blends has already been evaluated, revealing no concerns for hydrogen blends up to 2%[189]. Additionally, preliminary tests have suggested the feasibility of repurposing SNAM's depleted natural gas fields for pure hydrogen use[190]. A pilot test at SNAM storage sites aims to validate these findings over the long term. In the gas distribution sector, Italgas (DSO with 25% market share in Italy) can already accept up to 20% hydrogen[191] with less than 2% of the network made of steel, indicating a high-level of readiness for hydrogen integration across most of its infrastructure. However, despite these advancements, there is still several obstacles to be tackled[192]. One of the primary concerns is the uncertainty surrounding hydrogen production, which complicates network operators' planning and implementation efforts for network adaptation to accommodate hydrogen. The high costs associated with hydrogen production also act as a barrier to its broader development and adoption. Furthermore, the absence of clear regulations for the supply of pure hydrogen by DSOs presents an additional hurdle that needs to be addressed to facilitate the expansion of hydrogen infrastructure and usage in Italy.

4.3 Biomethane injection into the grid

Biomethane's chemical composition is similar to natural gas, but it typically has a higher oxygen content[193] (see Annex G: Oxygen limits) that can cause technical problems when injected into the gas transmission system. However, until now, oxygen contained in biomethane has not posed a significant issue, largely because the biomethane quantities injected into the gas network in the four CESEC countries (Figure 22) have been limited. Consequently, the oxygen concentration has been diluted to insignificant levels after local use and/or mixing with the natural gas.

[185] GCA (2022). Survey Response. 7 October
[186] SNAM and Hydrogen available at: https://www.snam.it/en/energy_transition/hydrogen/snam_and_hydrogen/
[187] SNAM (2019). The Renewable Gas in the Strategy of SNAM. [online] Available at: https://www.regatrace.eu/wp-content/uploads/2019/12/REGATRACE_SNAM.pdf
[188] ACER (2022). Opinion No 08/2022 on the Review of Gas and Hydrogen National Network Development Plans to assess their consistency with the EU Ten-Year Network Development Plan. [online] Available at: https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions%20Annexes/ACER_Opinion_08-2022-Annex_III.pdf
[189] SNAM (2022) Internal Large-scale hydrogen storage in depleted gas reservoirs - European Hydrogen Week. [online] Available at: https://hydrogeneurope.eu/wp-content/uploads/2022/12/53_S5_1.pdf
[190] SNAM (2021) 2021-2025 Strategic Plan. [online] Available at: https://www.snam.it/export/sites/snam-rp/repository/file/investor_relations/presentazioni/2021/2021_2025_Strategic_Plan.pdf
[191] Italgas (2022). Personal communication, 13 December
[192] Italgas (2022). Personal communication, 13 December
[193] A European common biomethane plant can produce biomethane with around 0.5% oxygen according to DGC' report on Biomethane handling O2 cost efficiently
[194] Research compiled from information gathered via interviews; ACER's Opinion No. 08/2022 of 16.12.2022; Gas for Climate (2022) Manual for National Biomethane Strategies

Figure 22 Infrastructure developments for biomethane injection as of today in CESEC region[194]

As Figure 22 illustrates, **Austria, Italy, Ukraine** and **Hungary**[195,196] are the only countries in the CESEC region making tangible progress in integrating biomethane into their national system as not only do they produce biomethane but also directly inject quantities of it into the existing gas infrastructure. The injection of biomethane in Austria takes place exclusively at the distribution level[197]. On the other hand, available information indicates that both the transmission and distribution networks in Italy and Hungary receive injections of biomethane[198]. One of the most significant challenges encountered in this process is the requirement to obtain approx. 24-25 permits for construction, operation, and grid connection, including the feed-in plan and penalty[199].

In **Austria**, the scale of biomethane injection into the gas network in 2021 amounted to 136 GWh, which represents approx. 0.15%[200] of the country's natural gas consumption. Biomethane injection takes place only at the distribution level (4 and 60 bars), enabling it to serve a diverse range of consumers.

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[195] ACER (2022). Opinion No. 08/2022 of 16 December 2022. [online] Available at: https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER_Opinion_08-2022.pdf.
[196] Gas for Climate (2022). Manual for National Biomethane Strategies. [online] Available at: https://www.europeanbiogas.eu/wp-content/uploads/2022/09/2022-Manual-for-National-Biomethane-Strategies_Gas-for-Climate.pdf.
[197] Austrian Association for Gas and Water (2023). Stakeholder's Workshop. 1 February
[198] Research compiled from ACER's Opinion No. 08/2022 of 16.12.2022; Gas for Climate (2022) Manual for National Biomethane Strategies
[199] Hungary's Country Network | BIOSURF
[200] Statistics Biomethan - AGCS Bioregisterstelle Österreich (biomethanregister.at)

In **Hungary**, there are two biomethane plants that purify biogas for injection into the distribution network[201]. Regarding legislative issues, according to the Hungarian Energy and Public Utility Regulatory Authority (MEKH), if the produced biomethane fulfils the quality standards for natural gas, it can be injected into the grid under the usual standards and procedures applicable to natural gas. Furthermore, the biomethane producer is responsible for financing the necessary investment for the connection, with the technical conditions being defined by the TSO[202]. While the framework appears clear, several obstacles hinder broader implementation. High costs that producers must cover to inject biomethane into the gas network pose a significant barrier. Furthermore, the lack of a clear national strategy as well as of a Guarantee of Origin system (which is expected to be set up in 2024) leads to infrastructure challenges that impede the integration of biomethane.

Finally**, Italy** has achieved significant progress in biomethane production and its injection into the grid, with most plants already connected to the gas networks[203]. The relevant legislative framework is comprehensive, facilitating the biomethane integration. Specifically, owners of biomethane plants can choose to connect to either the transmission or distribution network. Resolution 27/2019/R/Gas provides guidelines for determining and certifying the quantities of biomethane eligible for incentives under the 2018 Biomethane Decree[204]. It also introduces a cost-allocation mechanism between network operators and biomethane producers, where the connection costs for biomethane plant operators are calculated as the network investment costs minus the expected tariff income for the network operator, with a 20% discount for the plant operator [205]. Additionally, specific quality standards, including additional parameters (e.g., CO, NH3, H2, F, Cl) for biomethane injection, are in place, while common parameters for both natural gas and biomethane maintain the same thresholds, such as oxygen ≤0.6% mol. Despite these advancements, Italy faces challenges in further integrating biomethane, primarily due to the limited availability of gas injection points. Biogas plants are often located far from gas transmission infrastructure, necessitating investments and time to develop new injection points. Additionally, the growing number of production sites, which is expected to increase biomethane production in Italy by 3.5 bcm by 2026 according to the NRRP[206] measures, will inevitably place a significant burden on the commercial unit of the TSO, potentially delaying the uptake of this renewable gas[207]. Finally, considering that biomethane production is relatively steady throughout the year, whereas the local consumption profiles of DSOs are highly variable, matching demand and supply is a challenge. Since Italian DSOs cannot store natural gas, reverse flows-allowing gas to move from lower pressure pipelines to higher ones, from distribution to transmission networks could offer a solution to this issue[208].

4.4 Key findings

Given the increasing importance of renewable hydrogen and biomethane within the energy mix of individual countries, the CESEC region recognises the need for an infrastructure capable of supporting these renewable and low-carbon gases. Similarly, to the observations concerning solely the production and uptake of renewable hydrogen and biomethane across the region, the readiness of the infrastructure differs among the countries examined. Key findings include:

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[201] MEKH (2022). Survey Responses. 19 October

[202] ACER Report on NRAs Survey: Hydrogen, Biomethane, and Related Network Adaptation. Available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen,%20Biomethane,%20and%20Related%20Network%20Adaptations.docx.pdf

[203] EBA Statistical Report 2022

[204] Eyl-Mazzega, M. and Mathieu, P. (2019). BIOGAS AND BIOMETHANE IN EUROPE: Lessons from Denmark, Germany and Italy [online] Available at: https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf

[205] Eyl-Mazzega, M. and Mathieu, P. (2019). BIOGAS AND BIOMETHANE IN EUROPE: Lessons from Denmark, Germany and Italy [online] Available at: https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf

[206] Italian Ministry of Environment and Energy Security

[207] BIP Group. (2022). Biomethane, the green molecule to enable energy transition. Retrieved from https://www.bip-group.com/wp-content/uploads/2022/11/Biomethane-the-green-molecule-to-enable-energy-transition.pdf

[208] Italgas (2022). Personal communication, 13 December

- As of now, the region lacks infrastructure capable of accommodating pure hydrogen.
- Countries without existing gas infrastructure such as Montenegro and Kosovo might face the necessity of investing in new hydrogen-ready infrastructure from the ground up if such infrastructure development is duly justified.
- Currently, only a few TSOs have commenced testing parts of the existing transmission infrastructure with hydrogen blends. Hungary, Austria, Ukraine, and Italy are actively evaluating the compatibility of their gas network infrastructure with pure hydrogen.
- The materials used in the gas pipelines at the distribution level are more compatible with hydrogen than the steel used at the transmission level in terms of potential cost-effective conversion to transport pure hydrogen. However, tests for this purpose are currently being conducted only in Austria and Italy on their distribution networks.
- There is a need for increased cooperation across national TSOs in the region, especially given the varying levels of infrastructure compatibility with hydrogen.
- The existence of different gas quality standards across the region, particularly in terms of the oxygen levels, may hinder cross-border flows of mixtures of biomethane and natural gas, once the biomethane quantities increase substantially.
- The decentralised production of biomethane in small quantities poses logistical challenges, as locally produced biomethane must be served by only a limited number of injection points.
- Lack of regulation and incentives for upgrading biogas plants to produce biomethane pose significant regulatory and financial obstacles to the promotion of biomethane.
- Currently, only Austria, Hungary, Italy and Ukraine inject biomethane into their respective gas networks, with Italy being the only country that offers the plant owners the option to connect to either the transmission or distribution network.

5 Hydrogen infrastructure development and adaptation needs

5.1 Introduction

Building on the assessment of gas network readiness for renewable and low-carbon gases in Chapter 4, Chapter 5 delves into the infrastructure development and adaptation needs. It starts with a detailed examination of national investment plans, at both the Transmission System Operator and, where feasible, the Distribution System Operator levels, focusing on the deployment of renewable and low-carbon gases.

The overview is enriched by presenting relevant projects from publicly available sources, including the 1st PCI/PMI list, IPCEI projects, ENTSOG data, the Hydrogen Infrastructure Map and insights from stakeholder engagement activities. Through a high-level analysis of the compiled information, the Chapter aims to highlight the momentum in infrastructure development.

Chapter 5 also puts emphasis on the hydrogen projects specific to the CESEC region that are included in the 1st PCI/PMI list under the revised TEN-E Regulation. A significant portion of this part of the analysis is dedicated to exploring the optimal deployment of new hydrogen transmission infrastructures using the PLEXOS platform. With the region already advancing a substantial pipeline of infrastructure projects for the integration of renewable and low-carbon gases, the Chapter further outlines the accompanying challenges, grouped into policy, regulatory, financial and technical areas. The comprehensive overview is based on an exhaustive desktop study and incorporates feedback directly from interviewed stakeholders, wherever possible.

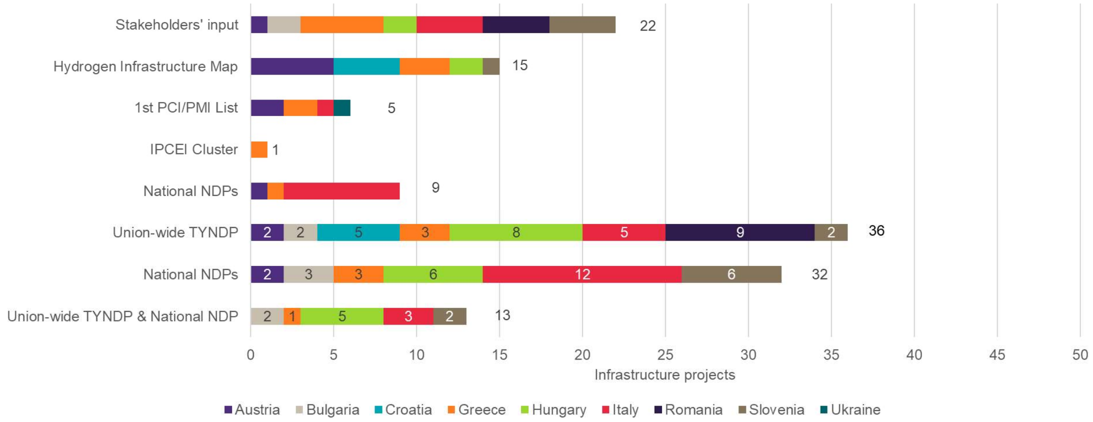
5.2 Planned infrastructure projects

To meet the Green Deal and REPowerEU objectives, the CESEC region needs to step up efforts to deploy renewable energy, including renewable and low-carbon gases. This requires, the development of a robust and adequate network of infrastructure capable of increasingly accommodating these gases. As a result, numerous projects are being developed within the region, as highlighted in national NDPs of TSOs and DSOs [209], Union-wide TYNDP 2022 Draft List of Projects[210], and the ENTSOG - H2 project visualisation platform[211]. The repository created for the purposes of this study also took into consideration the work visually presented in the Hydrogen Infrastructure Map[212] by ENTSOG, GIE, CEDEC, Eurogas, GEODE, GD4S in cooperation with European Hydrogen Backbone, projects from the two awarded IPCEI programmes (Hy2Use, Hy2Tech) and the 1st PCI/PMI list. Relevant input from stakeholders through surveys and interviews is included as well.

As anticipated, a single project might be featured in more than one of the aforementioned sources used for the repository of the study. Figure 23 illustrates the infrastructure projects promoted across each of the investment plans and sources used for gathering relevant information.

[209] Many of the TSOs in the region updated their TYNDPs after the revision of the TEN-E Regulation to include more relevant projects
[210] ENTSOG exceptionally published an updated TYNDP list of projects in October 2022 in response to the goals set in the EC's REPowerEU Plan and its associated initiatives to accelerate the integration of renewable gases
[211] Hydrogen project visualisation platform – ENTSOG
[212] H2 Infrastructure Map Europe (h2inframap.eu)

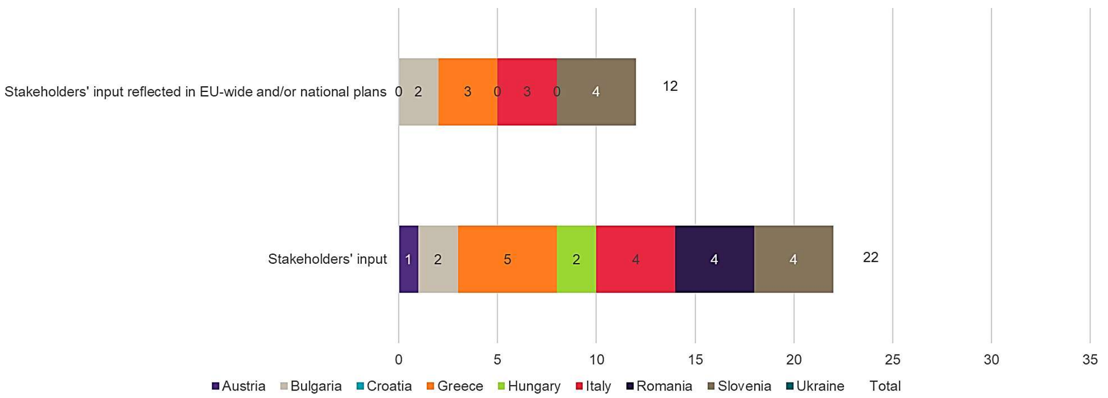
Figure 23 Number of infrastructure projects (distribution, transmission, storage and transmission) in the CESEC region featured in the investment plans and in other information sources. Projects concern biomethane, renewable and low-carbon hydrogen, fossil-based hydrogen with abatement, renewable hydrogen and fossil-based hydrogen with abatement, as well as renewable gases in general [213]



Source: own elaboration

The analysis reveals discrepancies between the number of projects listed in national NDPs and those featured in the Union-wide TYNDP. In addition, there is not a complete overlap between the projects listed in the national NDPs and those in the Union-wide TYNDP, and vice versa. Specifically, projects promoted in both national and Union-wide plans (bottom stacked bar in Figure 23) are two in Bulgaria, one in Greece, five in Hungary, five in Austria, three in Italy, two in Slovenia and none in Croatia, Romania and Ukraine. In some instances, projects at a more conceptual stage are mentioned by stakeholders during the interviews that are not featured in any of the national and/or Union-wide plans. As illustrated in Figure 24, these conceptual projects are two in Greece and Hungary, one in Italy, and four in Romania.

Figure 24 Stakeholders' input regarding promoted infrastructure projects at national level

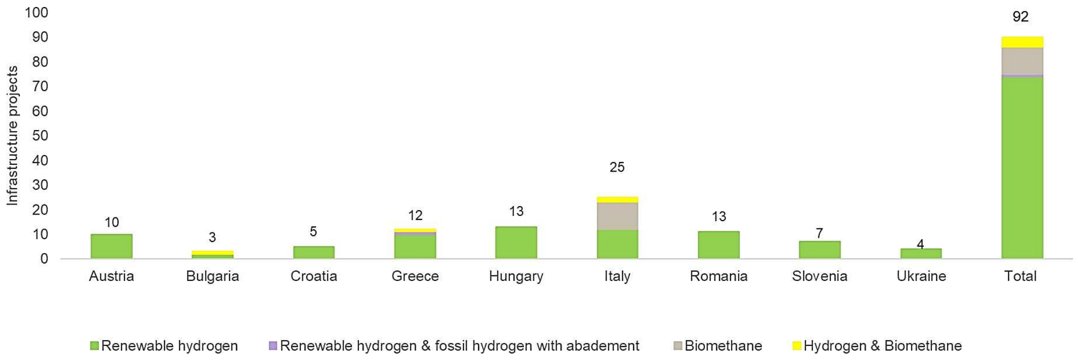


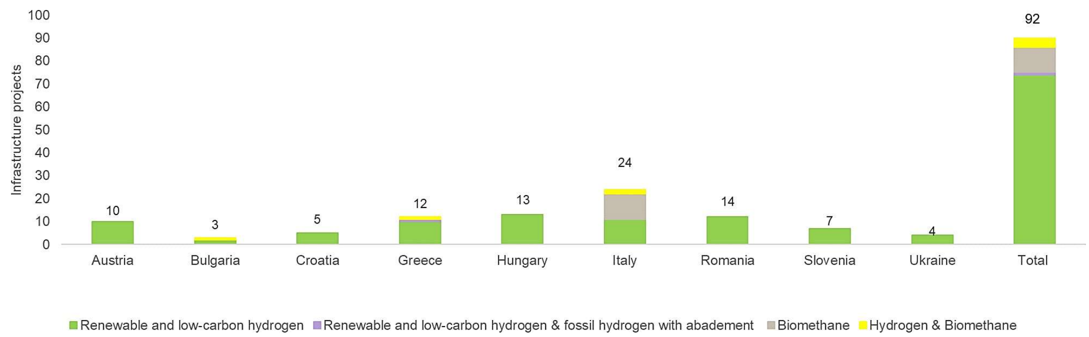
The review identified 92 individual infrastructure projects in total in the CESEC region. Those projects are either dedicated to a specific type of infrastructure (i.e., such as transmission networks, distribution networks, storage facilities, smart grids) or involve a combination of thereof, for instance, linking storage with transmission. Additionally, there are integrated projects (not counted in the total of 92) that encompass production of renewable and low-carbon gases and their end-uses. The projects highlighted are designed to

[213] Quantitative analysis on projects promoted through TSOs/DSOs NDPs, Draft ENTSOG TYNDP 2022 list, List of PCI/PMI candidate projects etc.

support either hydrogen or biomethane, and – less commonly – a broader range of renewable and low-carbon molecules.

Figure 25 Promoted infrastructure projects (transmission, distribution, storage, smart grids, storage, and transmission) in the CESEC region. Grouping per type of molecules





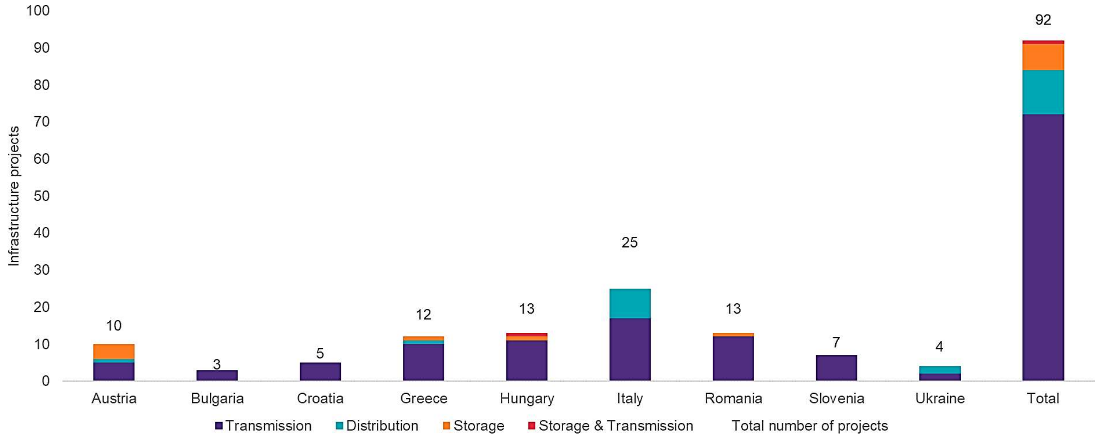
Source: own elaboration

Figure 25 illustrates that Italy, followed by Romania and Hungary, are the countries with the highest number of projects (i.e., transmission, distribution, storage, storage, and transmission) aimed at integrating hydrogen and biomethane in the region. Among all promoted projects, the vast majority (80%) concerns renewable and low-carbon hydrogen, whereas only 12% relate to biomethane alone. The latter type of projects is almost exclusively located in Italy. Four projects (representing 4%) labelled as “*Hydrogen & Biomethane*” are found in Italy, Bulgaria and Greece and are promoted either by a respective TSO or a DSO. These projects primarily target the development and integration of renewable and low-carbon gases. They encompass a variety of initiatives, including the construction of new pipeline infrastructure within the transmission network, the examination of the impacts of blending hydrogen with natural gas in the distribution network, and the construction of injection points for these gases. Necessary network adaptations such as regulating stations and the digitalisation of the distribution network are also part of these efforts. Additionally, a research project referred to as “*Renewable hydrogen and fossil-based hydrogen with abatement*” is promoted in Greece as part of the IPCEI awarded programmes. The project aims to construct innovative high-pressure tanks made from composite materials and carbon fibres for above-ground hydrogen storage.

Figure 26 illustrates a grouping of the aforementioned projects based on the type of infrastructure. It is evident that the vast majority of the projects promoted in the region focus on the transmission network (78%), followed by distribution (13%) and storage (8%). There is one project that combines both transmission network and storage located in Hungary. Its focus is to replace chromatographs currently in use in the country. None of the plans (national or Union-wide) and other publicly available sources analysed identify investments in facilities for receiving, storing, and regasifying liquefied hydrogen or hydrogen carriers. As already mentioned, in view of the inclusion of the SoutH2 corridor and Greece- Bulgaria in the 1st PCI/PMI list, the CESEC region will be able to serve potential needs in renewable hydrogen. Consequently, facilities for receiving, storing, and regasifying liquefied hydrogen or hydrogen carriers may become relevant only in the long-term perspective. Even then, such facilities could most likely be addressed to hydrogen carriers, rather than to liquified hydrogen. The rationale is that existing ammonia and methanol markets need to be served, and transporting renewable hydrogen in the form of carriers instead of pure can be more cost-efficient. For instance, based on current analyses and available data, Croatia is among the countries[214] that consume hydrogen for ammonia production. Additionally, the country's draft updated NECP[215] includes plans for constructing publicly accessible stations for ammonia supply.

Investments focused on smartening the grid are being promoted in the region, either as part of larger and multi-faceted projects or as standalone investments. Out of the 13 promoted smart-grid projects, 7 are featured in Italy's national plans. Most of the projects in Italy are at distribution level and focus on digitalisation of existing networks, enabling parameters (e.g., pressure) to be adjusted remotely and in real-time. This capability is crucial for operating networks with various gas mixtures. Italy also promotes reverse flow projects. In Hungary, there is a project promoted that involves replacing existing chromatographs with new ones that are compatible with hydrogen.

Figure 26 Promoted infrastructure projects in the CESEC region. Grouping per type of infrastructure



In general, not all hydrogen-related projects that are promoted fall under the hydrogen infrastructure categories outlined in TEN-E. The hydrogen infrastructure categories defined in the revised TEN-E Regulation are:

- Pipelines for the transport, mainly at high pressure, of hydrogen, including repurposed natural gas infrastructure, giving access to multiple network users on a transparent and non-discriminatory basis.
- Storage facilities connected to the high-pressure hydrogen pipelines referred to in point (a).
- Reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances with the objective of injecting the hydrogen, where applicable, into the grid.

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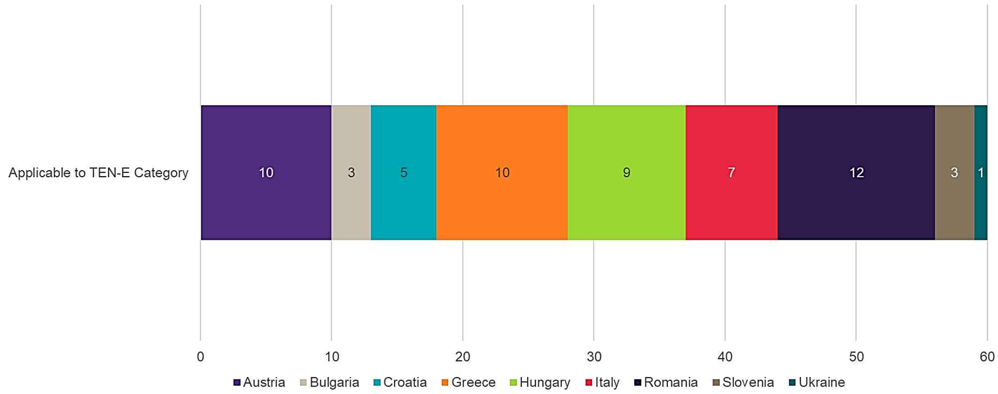
[214] Together with Hungary, Bulgaria, Greece, Italy, and Ukraine

[215] Draft updated NECP of Croatia, submitted July 2023. Available at: https://commission.europa.eu/publications/croatia-draft-updated-necp-2021-2030_en

- Any equipment or installation essential for the hydrogen system to operate safely, securely, and efficiently or to enable bi-directional capacity, including compressor stations.
- Any equipment or installation allowing for hydrogen or hydrogen-derived fuels use in the transport sector within the TEN-T core network identified in accordance with Chapter III of Regulation (EU) No 1315/2013 of the European Parliament and of the Council[216].

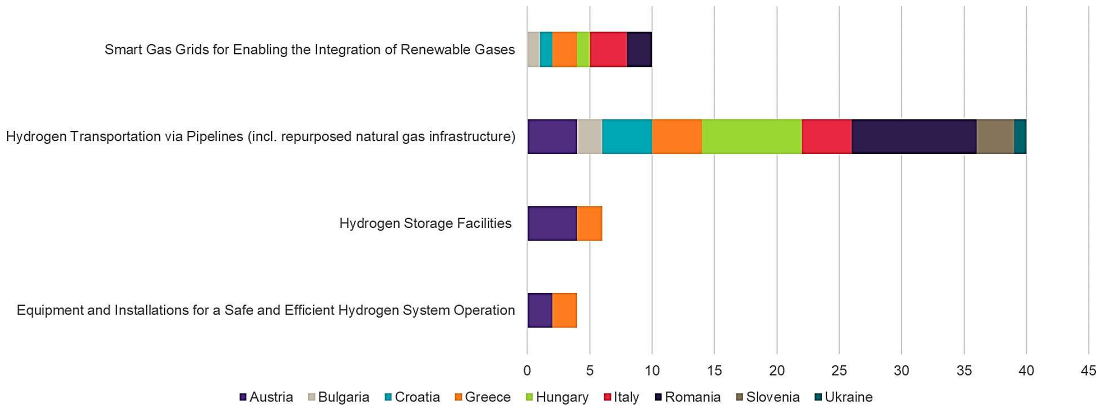
More specifically, Figure 27 shows that out of the 92 projects of renewable and low-carbon gases presented in the various sources, 60 fall under the energy infrastructure categories concerning hydrogen that are stipulated in Annex II of the revised TEN-E Regulation[217]. The difference in the number is due to the fact that not all 92 projects concern hydrogen (see Figure 25). Some of the hydrogen-focused projects are only dealing with blends instead of pure hydrogen, and – finally – a few projects are at very early development stage (i.e., studies).

Figure 27 Promoted infrastructure projects in the CESEC region that fall under TEN-E



Among the 60 infrastructure projects aligned with the hydrogen-related categories of the TEN-E regulation, the majority is focused on transmission pipelines. This is followed by projects dedicated to the development of smart grids (see Figure 28).

Figure 28 Break-down of the TEN-E infrastructure projects promoted in the CESEC region



Austria promotes investments in hydrogen transportation by pipelines, hydrogen storage facilities as well as equipment and installations necessary for a safe and efficient hydrogen system operation, such as metering

[216] Regulation (EU) No 1315/2013 of the European Parliament and of the Council of 11 December 2013 on Union guidelines for the development of the trans-European transport network and repealing Decision No 661/2010/EU (OJ L 348, 20.12.2013, p. 1)
[217] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32022R0869

stations and compressor stations. The investments in hydrogen transportation by pipelines include the three PCI projects (see Section 5.2.1). Bulgaria reported investments in hydrogen transportation by pipelines (i.e., the PCI project) and in smart gas grids. The latter project is a preliminary assessment of the compatibility of the network with hydrogen, which also encompasses the application of a smart hydrogen injection and operation system. In Croatia, the TSO promotes projects of similar type like the ones in Bulgaria. More specifically, the TSO proposed investments in hydrogen transportation by pipelines (i.e., either new or repurposed) and in smart gas grids (i.e., development of a "smart gas network"[218]) to be included in the 1st PCI/PMI list. Greece communicates the intention to invest in projects applicable to several TEN-E categories. More specifically, the country promotes a hydrogen project (i.e., construction of innovative high-pressure tanks from composite materials and carbon fibres for the storage of hydrogen especially for the transport sector), which is part of the IPCEI cluster of projects H2Tech. With regards to hydrogen storage, Greece proposed the conversion of the offshore depleted gas field of South Kavala to be included in the 1st PCI/PMI list. Two projects are promoted concerning the safe and efficient hydrogen system operation by the DSO and TSO, respectively. The latter is linked to the conversion of the South Kavala UGS, as it includes the implementation of a metering and regulating station at Kavala which ought to be compatible with hydrogen as well. Among the investments in hydrogen transportation by pipelines are the PCI project, as well as the project connecting Greece with North Macedonia, the Levante and the Poseidon projects. In Hungary, the vast majority of the promoted projects concern hydrogen transportation by pipelines, either new or repurposed, in order to allow hydrogen trade with Slovakia, Romania, and Ukraine. A further project concerns the installation of hydrogen-ready chromatographs (falling under the "Smart Gas Grids for Enabling the Integration of Renewable Gases" category). The aforementioned projects were proposed to be included in the 1st PCI/PMI list but – as reported in Section 5.2.1 – are not selected. Italy promotes investments in hydrogen transportation by pipelines (including the PCI project elaborated in Section 5.2.1) and in smart gas grids. With regards to the latter type of investments, those projects are mainly reported by the national DSOs and include, inter alia, pilot reverse flow facilities and digitalisation of assets. Romania primarily promotes pipeline infrastructure projects that are announced to be compatible with hydrogen and, to this end, were proposed to be included in the 1st PCI/PMI list, yet not finally selected. Slovenia and Ukraine only promote investments in pipeline infrastructure projects, all of which were proposed to be included in the 1st PCI/PMI list but only the generic corridor linking Ukraine with Germany is selected (see Section 5.2.1).

5.2.1 PCI/PMI projects

Out of all mentioned projects that focus on the integration of renewable and low-carbon gases and are promoted by various entities[219], particular emphasis ought to be placed on the 1st PCI/PMI list based on the revised TEN-E Regulation. The list features hydrogen interconnections in Central Eastern and Southeastern Europe that are highly relevant to the CESEC region, as they are located in Italy, Austria, Greece, Bulgaria and Ukraine (see Figure 29). Those are the:

- Hydrogen corridor Italy – Austria – Germany that encompasses internal hydrogen infrastructure projects, such as the Italian H2 Backbone, the H2 Readiness of the TAG pipeline system, the H2 Backbone WAG and Penta West and the HyPipe Bavaria – The Hydrogen Hub.
- Hydrogen interconnector between Greece and Bulgaria that constitutes 2 projects: the internal hydrogen infrastructure in Greece towards the Bulgarian border and the internal hydrogen infrastructure in Bulgaria towards the Greece border.
- Generic Corridor aiming to transmit hydrogen from Ukraine to Slovakia, Czechia, Austria, and Germany.

[218] includes advanced digital systems and components, control systems, sensor technologies, gas flow and quality management devices (compressors, gas flow control sets, reconstruction and chromatographic equipment, etc.)
[219] TSOs, or DSOs, Storage Operators and even Consortia of them with private players

Figure 29 Illustration of the PCI projects relevant to the CESEC region, as included in the PCI-PMI Transparency Platform[220]

Further details on the projects taking place in the CESEC countries are presented thereafter.

Hydrogen corridor Italy – Austria – Germany (The SoutH2 Corridor)

As shown in Figure 29, the circa 3,200 km hydrogen corridor stretches from the entry point in Sicily to the export point in Germany enabling the transport of hydrogen produced in Northern Africa (i.e., Algeria and Tunisia) towards European consumption centres. The corridor, referred to as the SoutH2 Corridor is a collaboration project of four TSOs, i.e., SNAM (Italy), TAG (Austria), GCA (Austria) and Bayernets (Germany). The import capacity from North Africa at the Italian entry point is circa 450 GWh/day and export capacity from Austria towards Germany is circa 150 GWh/day.

220 https://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

Italian H2 Backbone

The Italian stretch it is composed of around 1,920 km of pipelines (70% repurposed and 30% new built) and several 100 MW of compressor stations. The project has gained the endorsement of the Italian Government with signed letters from two Ministries[221].

H2 Readiness of the TAG pipeline system

The Austrian TAG part of the projects includes the repurposing of 1 out of 3 existing pipelines of TAG's system (380 km), including the change of components such as section valves, insulation joints, compressor stations and metering stations. The project connects the hydrogen pipeline at the Italian- Austrian border (Arnoldstein) with those at the Austrian-Slovak border (Baumgarten). It will be connected to the H2-WAG pipeline within Austria to supply central Austria and southern Germany and will be connected to Eustream's hydrogen pipeline. The project will be able to meet the local needs of customers in Austria and enable Italy, Germany, Slovakia, Czech Republic, and all of central and eastern Europe to develop a common hydrogen market, promoting competition and security of supply. As part of the hydrogen corridor Italy-Austria-Germany, the system is optimised to transport hydrogen from the SNAM system at 168 GWh/day capacity from low-cost production areas in North Africa[222]. The project is envisaged to be fully operational by 2030.

H2 Backbone WAG and Penta West

The purpose of the project is to enable cross-border bidirectional transport possibilities for hydrogen between Austria and Slovakia, as well as Austria and Germany. The hydrogen required can be obtained from different sources. Industrial clusters in Austria and Bavaria could be supplied with hydrogen from regions such as North Africa, Ukraine, Romania, and Croatia[223]. The project will supplement the West Austria Gas Pipeline (WAG) and the Penta-West Pipeline (PW) with a parallel line for hydrogen (200 km of new pipelines, 140 km of repurposed pipelines). The project also includes a compressor and metering stations. The development of this project is essential for addressing the hydrogen import needs of Austria and deliver hydrogen to the large demand centre along the route, in particular the wider area around Vienna and Linz. Additionally, the project allows for the connection to storage facilities in Austria, which helps to create security of supply with hydrogen[224].

Internal hydrogen infrastructure in Greece towards the Bulgarian border

The project consists of a new pipeline approx. 540 km long, with a possible branch approx. 250 km long and it will connect Athens and Corinth industrial areas with Thessaloniki and Kavala. Its overall purpose is to transmit pure hydrogen mainly from the southern part of Greece, up to the interconnection with Bulgaria. The hydrogen dedicated pipeline will be operating in parallel with the gas pipeline. The project includes 2 compressor stations and is expected to be operational in 2029[225].

Internal hydrogen infrastructure in Bulgaria towards the Greece border

The project consists of a new pure hydrogen transmission network (250 km long) and 2 compressor stations. The purpose of the project is to enable conditions for transmission of hydrogen from/to Greece and to the region of Sofia in Bulgaria. The project is expected to be operational in 2029. Subsequently, further expansion of the infrastructure on the territory of Bulgaria is possible both inside the country and to cross-border interconnection points with Romania and other neighbouring countries.

Generic corridor between Ukraine, Slovakia, Czechia, Austria, and Germany

The project's purpose is to transport hydrogen from major hydrogen supply areas in Ukraine through Slovakia and the Czech Republic to hydrogen demand areas in Germany[226]. The corridor for the transportation of hydrogen from Ukraine to Germany is foreseen to mainly repurpose existing gas

[221] SoutH2 - The initiative (south2corridor.net)
[222] EHB-2023-20-Nov-FINAL-design.pdf
[223] https://h2backbone-wag-pw.at/en/home-english/
[224] EHB-2023-20-Nov-FINAL-design.pdf
[225] EHB-2023-20-Nov-FINAL-design.pdf
[226] Project - Central European Hydrogen Corridor (cehc.eu)

infrastructure and compressor stations. The project aims to be operational by 2030, with later target transport capacity of up to 1.5 Mt/y (144 GWh/d), and is currently in the pre-feasibility phase, focusing on assessment of the technical feasibility and the investment required to prepare the existing natural gas infrastructure to transport hydrogen[227].

5.2.2 Repurposed vs new hydrogen infrastructure

A critical question regarding infrastructure deployment concerns the choice between constructing new dedicated pipelines or refurbishing existing ones. Early promoters of renewable hydrogen in the region may find greater benefits in prioritising the repurposing of part of their gas assets rather than building new ones, which can take significantly longer (i.e., 6 to 12 years for natural gas pipelines)[228]. Making part of the gas network compatible with pure hydrogen requires investments in the pipes, valves, compressors, and metering stations. The technical feasibility of repurposing a natural gas pipeline to hydrogen should be examined on a case-by-case basis, as it depends on the material composition of the pipeline and its operational characteristics. Thus, repurposing can vary from simple adjustments (e.g., replacing valves, meters, and other components) to more complex refurbishments, including installing new compressor stations and replacing/ recoating pipeline segments, depending on operation conditions[229]. Pipeline segments in hydrogen installations should, whenever possible, be permanently welded or hard soldered because this ensures long-lasting leak proofness[230]. However, the economic and technical viability of repurposing is closely tied to the ability of transmission systems to maintain accommodating the current levels of natural gas demand. Thus, repurposing efforts until 2030 seem more feasible in denser systems, such as those in Austria, Italy, and Ukraine, compared to those in Greece and Bulgaria. This distinction is also evident in the projects included on the 1st PCI/PMI list.

When examining the existing LNG terminals in the region, there are only six operational ones located in Croatia, Greece and Italy, none of which are compatible with hydrogen. Hydrogen-compatible terminals will only become relevant for the region if the demand for hydrogen or its production in the region is expected to be substantial and exceed local production capacity and demand, respectively. Should the region be unable to meet demand with indigenous production, terminals might facilitate imports. According to the analysis in Chapter 3.3, based on the most recent data available for each country, regional demand is anticipated to exceed the supply by 8 TWh by 2030. Moreover, the unserved demand could by met entirely by the SoutH2 corridor recently included on the 1st PCI/PMI list that has a hydrogen import capacity of 4.4 Mtpa (equivalent to 147 TWh).

Identification of specific infrastructure priorities is a complex task that cannot be based solely on the stated ambitions outlined in national strategic documents. It requires substantial financial resources due to the capital-intensive nature of infrastructure projects, alongside meticulous planning to prevent stranded assets and ensure investments are future-proof. A critical preliminary step in this planning phase involves assessing the compatibility of national networks with hydrogen. This assessment has already been initiated in the region by gas TSOs and DSOs.

5.2.3 Transportation modes of pure hydrogen

There are three transportation modes of hydrogen from the production to the consumption centres, i.e., pipelines (either new or repurposed), ships and trailers. The choice of transportation mode depends on the volumes to be transported and the distances to be covered, with cost considerations guiding the selection.

Although the exact breakeven point would require a more detailed economic analysis, pipeline transport is generally considered as the most cost-efficient option. The cost-effectiveness of using hydrogen- dedicated

[227] EHB-2023-20-Nov-FINAL-design.pdf
[228] Global Hydrogen Review 2023, IEA
[229] Facilitating-hydrogen-imports-from-non-EU-countries.pdf (gasforclimate2050.eu)
[230] Safety Advice. 13 – Handling with Hydrogen. Linde

pipelines depends on whether these pipelines are new or repurposed gas assets. The primary cost components for a gas pipeline include the capital expenditure (CAPEX) and operational expenditure (OPEX) for both the pipeline itself and the compressors. According to a Gas for Climate Report[231] which cites TSO simulations, the CAPEX for the pipeline is most significant cost factor for new networks, whereas compressor OPEX becomes the most substantial cost component for repurposed networks. This difference arises because, in the case of repurposing, the pipeline CAPEX constitutes only 10-35% of the CAPEX required for a new hydrogen pipeline of a similar diameter[232].

Shipping hydrogen and hydrogen carriers (e.g., ammonia) is another viable import option for larger distances where pipelines are unfeasible. Until recently, this approach had not reached commercial status. Specifically, it was not until 2022, when the first shipment of liquid hydrogen (LH_2) took place from Australia to Japan as part of a pilot project (with a cargo capacity of 1250 m^3) to gain real experience in LH_2 shipping[233]. Conversely, ammonia has been a tradable commodity for many years[234] rendering the shipping of this form of hydrogen not a novelty. However, ammonia is highly toxic, flammable, and explosive under certain conditions. Therefore, stringent safety measures must be ensured for its transport. In general, shipping of hydrogen or hydrogen carriers involves multiple steps, including:

1. Hydrogen transport via pipeline from the production site to the export terminal
2. Conversion of gaseous hydrogen into the shipping medium (LH_2 or hydrogen carrier)
3. Storage at the export terminal
4. Shipping (as LH_2 or as hydrogen carrier)
5. Storage at the import terminal
6. Reconversion to gaseous hydrogen
7. Hydrogen transport via pipeline to the demand location

As inferred, the energy losses incurred are considerable in the case of hydrogen shipping. Specifically, energy losses of 30-36% must be taken into account for hydrogen liquefaction at cryogenic temperature (-253°C)[235] alone. Although handling hydrogen carriers improves operational conditions, the transportation process involves more steps for converting and extracting hydrogen, which impact the total efficiency and purity of hydrogen. Energy losses translate into costs (liquefaction costs at 1,350 EUR/kWh and regasification costs at 273 EUR/kWh[236]) and, therefore, the objective is to choose the hydrogen carrier that will ultimately be consumed. Hydrogen carriers such as methanol and ammonia have standalone markets of their own in Europe. Therefore, it is economically more viable to transport renewable hydrogen in the form of these carriers to replace existing uses of fossil-equivalent molecules.

For short and medium distances (up to 500 km) and for smaller quantities to be transported, trailers could be more cost-effective compared to pipeline systems. Trucks are versatile and can transport either LH_2, or when converted, into a denser chemical form such as ammonia. The trailer transportation of compressed hydrogen involves compression and storing of the produced quantities in designated vessels, which are then loaded onto a trailer and transported to the consumption site. It is noteworthy that safety regulations impose restrictions on the carrying capacity aboard a trailer.

[231] European Hydrogen Backbone (2021). Analysing future demand, supply, and transport of hydrogen. https://ehb.eu/files/downloads/EHB-Analysing-the-future-demand-supply-and-transport-of-hydrogen-June-2021-v3.pdf
[232] Gas for Climate: European Hydrogen Backbone, July 2020. Available at: https://ehb.eu/files/downloads/2020_European-Hydrogen-Backbone_Report.pdf
[233] On the bulk transport of green hydrogen at sea: Comparison between submarine pipeline and compressed and liquefied transport by ship - ScienceDirect
[234] Only in 2021, 18 million metric tons of ammonia were traded worldwide (Global traded ammonia volume 2021-2050 | Statista)
[235] Ronald Berger. Hydrogen transportation / The key to unlocking the clean hydrogen economy. Available at: file:///C:/Users/maslanoglou/Downloads/roland_berger_hydrogen_transport-1.pdf
[236] GIE (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment. Available at: https://www.gie.eu/wp-content/uploads/filr/2598/DNV-GL_Study-GLE-Technologies-and-costs-analysis-on-imports-of-liquid-renewable-energy.pdf

The main advantages and disadvantages, and associated costs of the different modes of transport are demonstrated in Table 7. These data have been retrieved from publicly available reports, including Gas for Climate[237] and deliverables of EU-funded projects[238].

Table 7 Main characteristics of hydrogen transport technologies

Type of transport	Pros	Cons	Costs
Pipeline	• Low CAPEX for repurposed pipelines • Low operational costs, long operational lifetime • Can cover very long distances • Pressure can be adapted for continuous supply	• High CAPEX for new pipelines • Time-consuming development due to complex permitting • Fixed routing may limit access for some consumers	4.4 mln EUR/km for a new 48-inch pipeline at 80 bar; 0.88 mln EUR/km for a repurposed 48-inch pipeline at 80 bar [239]
Ship	• Attractive alternative for longer distances, where pipelines are not an option • Flexibility (no dependency on a given supplier) • Mature technology for ammonia transportation	• No experience in shipping compressed hydrogen • LH_2 needs specialized ships that are not yet commercially available • Liquid carriers have high conversion costs and energy use	4,050 EUR/kg2 shipping LH2[240]
Trailer	• Commercially available and mature technology • CGH2 is the cheapest option for short distances • Suitable option even for long-distance	• Low gravimetric and volumetric density in CGH2 • Handling and losses in LH_2 • Liquid carriers require conversion and reconversion • Safety concerns	884 EUR/kgH2 CAPEX trailer for CGH2 (500 bar) 181 EUR/kgH2 CAPEX trailer for LH2 (500 bar)[241]

As a concluding remark on the selection of the most cost-effective transport mode, it is apparent that optimal choices are dictated by specific circumstances. For transporting consistently, pipelines are preferred for their ability to transport large volumes, despite high initial capital expenditure (CAPEX) that scales linearly with length. Operational expenditure (OPEX) remains relatively low and increases marginally with higher volumes.

For small to medium quantities where pipelines are not viable, compressed gas hydrogen (CGH_2) or liquid hydrogen (LH_2) tube trailers might be viable options. Liquid hydrogen is generally most cost-effective over longer distances. Similar to road transport (i.e., trailers), shipping hydrogen becomes relevant in the absence of pipelines, but this is practical only for significant quantities and very long distances. The choice of form (as is or in a carrier) and state (i.e., compressed, liquified) of hydrogen influences cost structure. For instance, LH_2 requires more energy for liquefaction compared to using a carrier like ammonia or methanol, it does not require additional conversion and reconversion infrastructure.

[237] European Hydrogen Backbone (2021). Analysing future demand, supply, and transport of hydrogen. https://ehb.eu/files/downloads/EHB-Analysing-the-future-demand-supply-and-transport-of-hydrogen-June-2021-v3.pdf
[238] Hydrogen Transport and Storage Cost Report (publishing.service.gov.uk)
[239] Gas for Climate: European Hydrogen Backbone, July 2020. Available at: https://ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf
[240] GIE (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment. Available at: https://www.gie.eu/wp-content/uploads/filr/2598/DNV-GL_Study-GLE-Technologies-and-costs-analysis-on-imports-of-liquid-renewable-energy.pdf
[241] HYDROGEN SUPPLY AND TRANSPORTATION USING LIQUID ORGANIC HYDROGEN CARRIERS (HYSTOC)

5.3 Mid to long-term investment needs for hydrogen transmission capacity

5.3.1 High level overview of modelling approach

Two scenarios have been elaborated in the context of the modelling analysis. The rationale for structing the two scenarios is based on the level of hydrogen interconnectivity of the CESEC region as presented below:

- **Scenario A – CESEC Regional.** This scenario focuses exclusively on the CESEC countries (internally interconnected with each other as applicable), using existing power and gas interconnections, but isolated in terms of hydrogen cross-border transportation from the rest of Europe and Africa) without imports to or exports from the CESEC region. Under this scenario the PCI/PMI hydrogen projects are not included by default, but the model freely optimises the deployment of hydrogen transmission projects from a list of candidate projects submitted for the 1st PCI/PMI process. The overarching rationale behind the assumptions under Scenario A is to assess the demand and supply patterns exclusively in the CESEC region, even though it may not fully align with the anticipated reality and the PCI/PMI process. This scenario can provide insights for the development of the hydrogen transmission system in the region.
- **Scenario B – CESEC + Germany / North Africa**. This scenario aligns with the PCI/PMI process and integrates the PCI/PMI projects between Greece-Bulgaria, Italy-Austria-Germany *(*i.e. SouthH2 Corridor[242]) and Ukraine-Slovakia-Czech Republic-Germany. The implementation horizon for the latter is foreseen after 2035. Thus, the major difference with Scenario A is that the model considers the increased hydrogen demand in Germany, as well as the prospect of large-scale hydrogen production in North Africa, transported through Italy to the CESEC region. The consideration of demand in Germany and production in North Africa under Scenario B, and the respective results showcased by the analysis, further validate the importance and necessity of the PCI/PMI projects.

5.3.2 Assumptions of the modelling analysis

In the modelling analysis, numerous assumptions regarding hydrogen demand, fuel sourcing, electricity generation mix, transmission infrastructure as well as hydrogen candidate transmission infrastructure projects are considered as prescribed in the context of national policy and strategic documents (such as NECPs, NHSs, TYNDPs, etc.).

Hydrogen Demand and Production data and respective targets in the region

Key methodological assumptions with regards to hydrogen demand in the region are presented below:

- **Data sources for hydrogen targets.** To represent hydrogen demand, publicly available data are considered from official sources such as the NECPs, NHSs, etc., as well as data/forecasts provided by stakeholders in the interviews conducted, namely European Commission and gas TSOs. It should be noted that for the purposes of the modelling analysis, demand-related data have been retrieved from the latest version of the NECPs of Member States and Energy Community Contracting parties, that were published until 31/10/2023, which was considered as the agreed "data freeze" point. All hydrogen demand related targets are assumed to refer to renewable hydrogen for 2030 and onwards. For countries which do not have hydrogen supply and demand targets or forecasts in formal policy documents, hydrogen demand is assumed to be zero and, consequently, no electrolysers are assumed to be developed in those countries.
- **Time series of demand.** Hydrogen demand. In cases where demand values obtained from NECPs (or other sources) refer only to specific years/milestone (e.g., 2030 or 2050), linear extrapolations are made to represent the overall time-series of demand. It should be highlighted

[242] SouthH2 - Home (south2corridor.net)

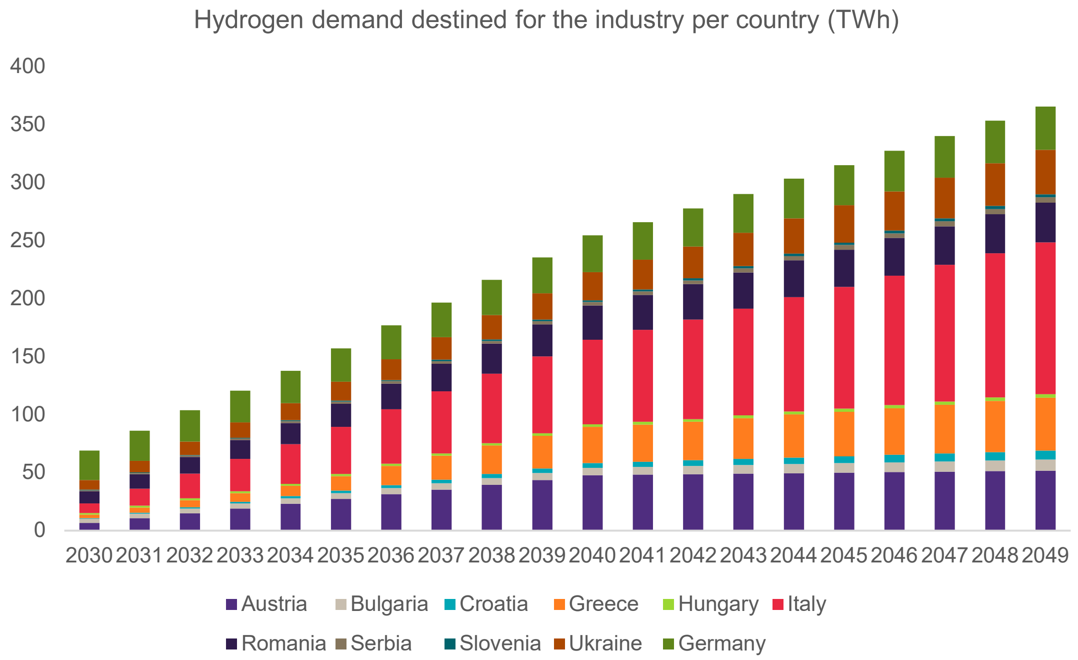
that major difficulties are encountered with respect to mapping demand due to limited data and conflicting information between various sources (particularly between NECPs, NHSs and data provided in the context of the PCI/PMI process[243]).

- **Hydrogen demand in Germany and production in North Africa.** Particularly for structuring scenario B - CESEC + Germany / North Africa, the analysis also considers the demand and supply in non-CESEC countries, especially Germany and North Africa, respectively. Regarding Germany's hydrogen demand, this refers to an assumed "contracted"[244] import between Germany and Italy via Austria, supplied by electrolyser production in North Africa (Algeria and Tunisia). Currently, hydrogen demand in Germany stands at approx. 55 TWh, predominantly based on fossil-based hydrogen in industry. According to the country's NHS, total demand by 2030 is projected to be in the range of 95-130 TWh (hydrogen and hydrogen derivates), with 50-70% of this demand expected to be met by imports (45-90 TWh) by 2030. Notably, Germany is in the process of developing a separate Hydrogen Import Strategy. Looking ahead to 2045-2050, demand expectations for the industrial sector are estimated to be between 290-440 TWh and for the electricity sector, between 80-100 TWh. Data related to renewable hydrogen production in North Africa are based on estimates provided by SNAM for 2030 and for 2050, considering a gradual increase through the time horizon. Out of these projected production volumes, Germany is anticipated to import approx. one-third (33%) through hydrogen transmission pipelines in Italy and Austria, according to SNAM. For the purposes of the modelling analysis, it has been assumed that from those import needs, and assuming average prices[245], Germany could satisfy approx. 40% of its hydrogen import needs overall from the CESEC region, and the rest of its import needs would be satisfied from other regions neighbouring to Germany. Specifically, this amounts to 25.47 TWh of imported energy in Germany in 2030 reaching gradually 37.64 TWh in 2050.
- **Hydrogen end uses.** In the absence of more disaggregated sectoral data on hydrogen demand reported or provided for specific CESEC countries, it has been assumed that hydrogen stated in the NECPs or NHSs is primarily destined for industrial consumption (cement, refineries, steel, chemical industries), with a fraction allocated to the transport sector, as explained thereafter. More specifically, it has been assumed that:
    - **Hydrogen for power generation.** It is assumed that renewable hydrogen will not be made available for power generation purposes, as this is deemed as economically unviable and energy intensive. Instead, all new gas fired power generation capacity to be built in CESEC region post-2030 will be supplied exclusively by natural gas and biomethane, whereas all existing units until 2030 will be served by natural gas.
    - **Hydrogen in the transport sector.** Demand for hydrogen in the transport sector, being low particularly in the early years of hydrogen deployment, is assumed to be satisfied through domestic (i.e. national) production via distribution (physical or virtual) or local networks. Hence, these quantities are not relevant for cross-border trade. In cases where hydrogen demand for transport is explicitly reported in the NECPs (or equivalent policy documents), the reported volumes are deducted from the total national hydrogen demand that will be satisfied through cross-border flows. In all other cases, demand in the transport sector is assumed to constitute 20% of the total hydrogen demand.

[243] PCI/PMI process needs - Regional Groups meeting 20/03/2023
[244] The term "contracted" refers to a fixed demand that needs to be covered under all circumstances
[245] 60% of needs to be covered by imports and average demand of 112,5 TWh

Respective demand data throughout the period 2030 – 2049 are presented in Figure 30. With regard to Germany, demand refers only to the assumed imports from the SouthH2 corridor throughout the assessed period under a moderate import scenario, and not Germany's entire hydrogen demand. Demand in Germany is pertinent only to Scenario B.

Figure 30 Total annual renewable hydrogen demand in the industrial sector in the CESEC region and Germany (in TWh)



Power generation and required electrolyser capacity

Regarding the power generation mix, publicly available data from the Reference Scenario 2020[246] on the evolution of the fuel mix, particularly concerning the installed renewable capacity in each country, has been utilised. Electrolysers in the model are represented as an additional electrical load that needs to be served. It has also been ensured that the techno-economic potential of renewable energy sources in a specific country is not exceeded (effectively the techno-economic potential serves as a cap for the RES that can be deployed in each country according to the analysis conducted in Section 3.2).

To meet hydrogen demand, the model optimises locations (i.e. countries) for deploying electrolysers based on the cost of renewable electricity. This process increases system loads and underscores the need for renewable-based electricity generation. To assess hydrogen deployment/integration up to 2050, the analysis is conducted allowing the mathematical model to determine the optimal incremental development of new renewable energy sources, including PV, onshore wind, and offshore wind. This complements existing RES development planned for power generation purposes (i.e., to serve an additional electrical load from electrolysers). Moreover, the model ensures that for each country and technology, development does not exceed the maximum realisable RES potential (see Table 3). Theoretical maximum capacities (in GW) are calculated based on technical potential estimations, accounting for size and technology maturity.

[246] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en

Transmission Infrastructure

As explained in Section 2.6, the hydrogen model is built on top of the power and gas model. As such, it already has specific electricity generators and battery storage systems installed in all CESEC countries. However, to meet the incremental RES capacity increase as a result of hydrogen demand (considering that all hydrogen production will be renewable hydrogen), the model determines the optimum location for the deployment of additional RES capacities in order to satisfy electricity loads of electrolysers. Key methodological assumptions and considerations with regards to transmission infrastructure include:

- **Treatment of PCI/PMI projects and list of predetermined projects.** In Scenario A the model optimises the hydrogen transmission infrastructure deployment by "building" the necessary hydrogen transmission pipelines among the CESEC countries of the region (and non-CESEC countries in Scenario B, namely Germany and Tunisia) in order to cover the forecasted demand in each country. More specifically:
  - In Scenario A, the model is given freedom to optimise transmission infrastructure deployment. Thus, the model considers building (or not) a pipeline from a predetermined list of candidate transmission projects, which include PCI/PMI projects, as well as hydrogen pipelines between almost all neighbouring countries of the CESEC region, depending on their cost-effectiveness compared to alternatives, such as increasing the local hydrogen production or alternative hydrogen pipelines. Therefore, under Scenario A, the model does not necessarily include all hydrogen PCI/PMI projects.
  - In Scenario B, hydrogen transmission PCI/PMI projects are consistently included in the model, as these are the projects promoted with high certainty. Additionally, beyond 2034, the model optimises the deployment of transmission infrastructures from a pre-determined list of transmission projects. This approach aligns closely with anticipated realities, reflecting TSOs' promotion of PCI/PMI projects based on their own analysis and as verified by the European Commission.
- **Treatment of repurposed vs. new assets.** The key output of the model are the cross-border flows and the required transmission infrastructure capacity. Therefore, the modelling analysis does not distinguish between re-purposing existing natural gas pipeline networks and constructing new dedicated pipelines.
- **Hydrogen storage.** Finally, although the 1st PCI/PMI list does not contain any hydrogen storage projects in the CESEC region, the analysis assumes presence of hypothetical hydrogen storage facilities. These are envisaged to balance projected intra-country flows, aligning with expected seasonal demand peaks in winter and storage injections in spring and summer. The prospect of high-volume seasonal hydrogen storage remains highly uncertain. Consequently, the analysis maintains a technology-agnostic stance towards hydrogen storage, without presuming any capital expenditure for commissioning such assets.

5.3.3 Key findings of the modelling analysis

This section presents the main quantitative results of the planning analysis focusing on the potential development of hydrogen infrastructure in the CESEC region for the period 2030 to 2050.

Required hydrogen cross-border transmission capacity

As discussed, Scenario A assumes no interconnection outside the CESEC region and therefore the respective PCI projects are not included. In contrast, Scenario B includes all PCI projects. Beyond 2034, additional transmission projects have been included in the model other than all PCI/PMI projects. Table 8 presents the required hydrogen transmission capacity under both scenarios in years 2030, 2040 and 2050 in GWh/day. For guidance purposes, the following nomenclature applies:

- Fields marked with "X", refer to unavailable transmission capacities until a respective year time horizon i.e. pipelines not included in the candidate list of transmission projects up to a specified year and therefore unavailable for the model to choose building them for the respective scenario.

- Fields marked with "-", refer to transmission capacities that are available from the candidate projects, but it is not economically optimal to deploy them, according to the model resolution.
- Projects are flagged according to their inclusion or not in the 1st PCI/PMI list in the first column.

able 8 Required transmission capacity for the two Scenarios for horizons 2030, 2040 and 2050 (in GWh/day)

PCI/PMI	Border		Scenario A - CESEC Regional			Scenario B – Regional + Germany / North Africa		
(yes/no)			2030	2040	2050	2030	2040	2050
Yes	AT-DE	Austria - Germany	X	X	X	150	150	150
No	AT-HU	Austria - Hungary	33.1	33.1	33.1	-	33.1	33.1
No	AT-SI	Austria - Slovenia	-	32.8	32.8	X	32.8	32.8
Yes	BG-EL	Bulgaria - Greece	70	70	70	70	70	70
No	BG-RO	Bulgaria - Romania	70	70	70	-	70	70
Yes	CZ-DE	Czechia - Germany	X	X	X	X	144	144
No	HU -HR	Hungary - Croatia	-	49.2	49.2	X	49.2	49.2
No	HU-RO	Hungary - Romania	70	70	70	X	70	70
No	HU-SK	Hungary - Slovakia	X	X	X	X	100	100
Yes	IT-AT	Italy - Austria	167.8	167.8	167.8	167.8	167.8	167.8
No	SI-HR	Slovenia - Croatia	-	32.8	32.8	X	32.8	32.8
No	SI-HU	Slovenia - Hungary	-	19.6	19.6	X	-	19.6
No	SI-IT	Slovenia - Italy	-	19.6	19.6	X	-	19.6
Yes	SK-AT	Slovakia - Austria	X	X	X	-	32.8	32.8
Yes	SK-CZ	Slovakia - Czechia	X	X	X	X	144	144
Yes	TN-IT	Tunisia - Italy	X	X	X	450	450	450
No	UA-HU	Ukraine - Hungary	35	35	35	X	-	35
No	UA-RO	Ukraine - Romania	-	50.6	50.6	X	50.6	50.6
Yes	UA-SK	Ukraine - Slovakia	X	X	X	X	144	144

Below analysis for each specific scenario is presented. Cross-border flows are presented for 2030 and 2045 (instead of 2050), due to the high degree of uncertainty for that time-horizon.

Cross-border -flows in Scenario A – CESEC Regional

Key findings for Scenario A include:

- As general remark, the produced quantities do not appear to be sufficient to justify widespread development of transmission infrastructure. This is because only parts of a south-to-north corridor are built (70GWh/d) from Greece to Bulgaria, Romania to Hungary, with pipelines branching to Austria and Ukraine. Flows are observed only in the corridor Hungary-Austria-Italy, as illustrated in Figure 31.
- To satisfy the projected hydrogen demand for 2030 in the region, it appears that countries develop local infrastructure first to meet local demand. This is a reasonably expected outcome, as demand is anticipated to gradually unfold in the CESEC countries, and domestic production is primarily intended to meet domestic demand, with minimal need for large-scale of cross-border trading.

- Beyond 2030, significant development of renewable energy sources and electrolysers is observed in the countries with the lowest levelised cost of electricity, resulting in the lowest levelised cost of hydrogen. This effectively indicates that countries with the largest RES potentials also have the largest capacities for renewable hydrogen, capable of serving demand across the region. Thus, in the period after 2030, the prospects for the economic feasibility and eventual realisation of a hydrogen corridor in the Balkan region are highly positive. Moreover, significant development of infrastructure between Austria and Italy is observed, with Italy absorbing quantities due to its own high needs.

Figure 31 Annual hydrogen cross-border flows and production in the CESEC region for 2030 under Scenario A – CESEC Regional

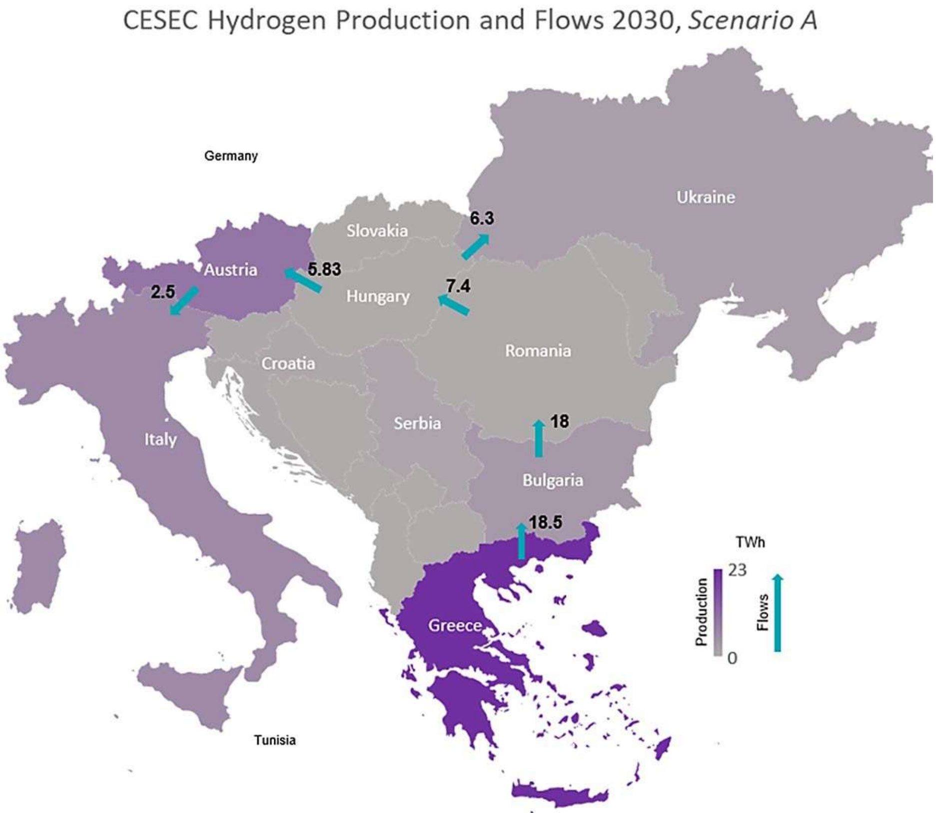
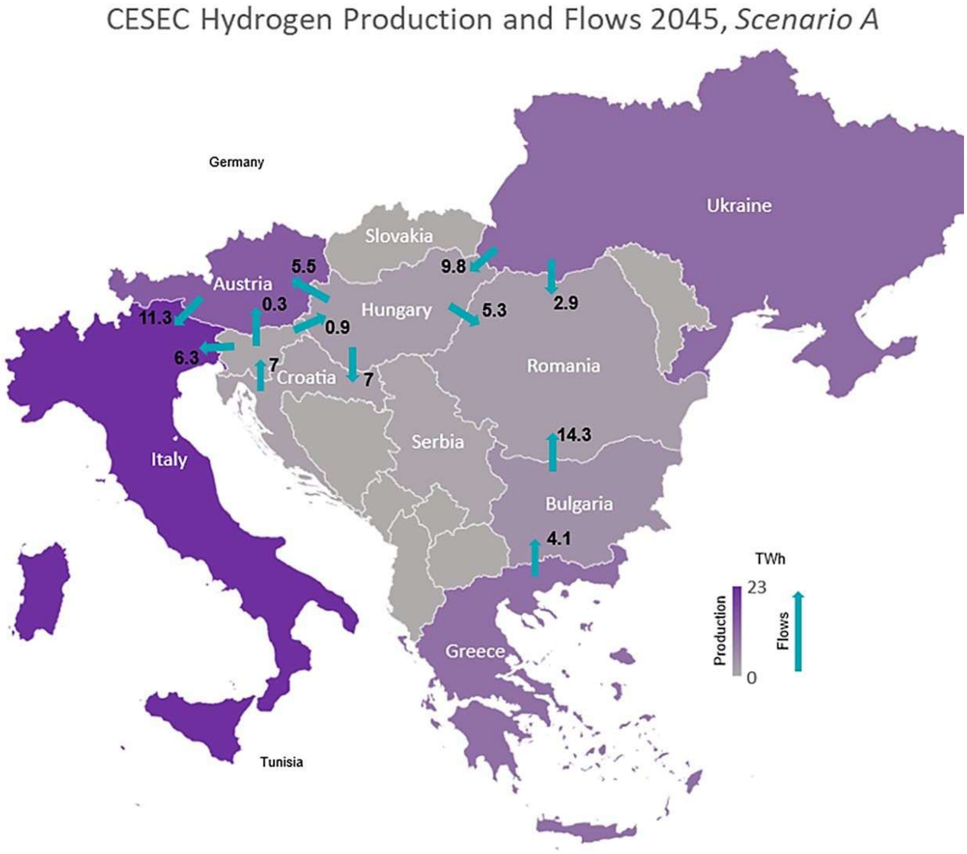


Figure 32 Annual hydrogen cross-border flows and production in the CESEC region for 2045 under Scenario A – CESEC Regional



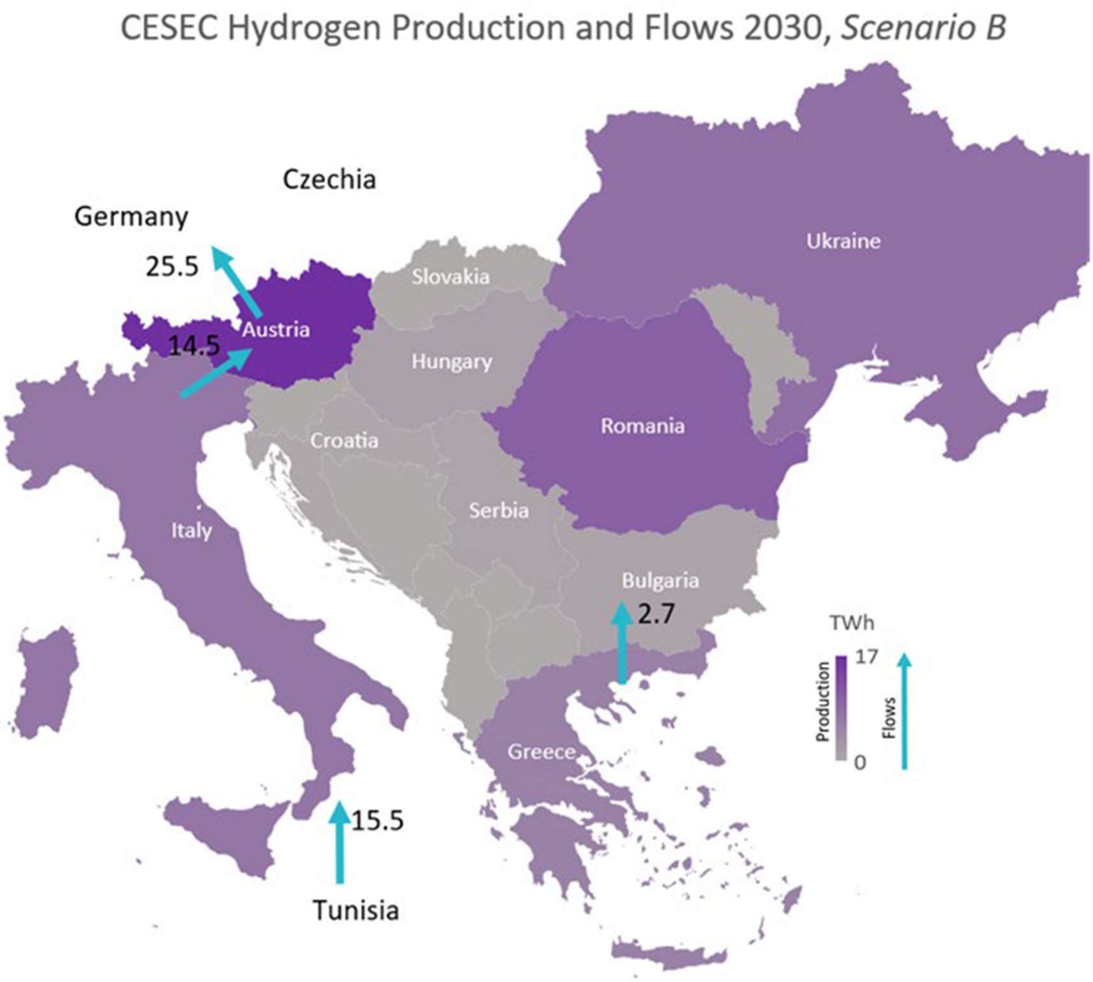
Cross-border -flows in Scenario B – CESEC + Germany / North Africa

Key findings for Scenario B include:

- For the horizon of 2030, only PCI/PMI projects materialise, as illustrated in Figure 33. Specifically, substantial flows are observed from Tunisia through Italy (approx. 14,5 TWh) along with local hydrogen production in Austria flowing onward to Germany (approx. 25,5 TWh). The Generic Corridor from Ukraine is assumed to materialise after 2035.
- Beyond 2040, the flows in the Italian section of the SouthH2 corridor to the north begin to gradually weaken due to Italy's rapidly increasing demand. Another contributing factor is the assumption that large electrolyser installations in North Africa are constructed overnight without further expansion later, while electrolysers developed in the CESEC region in the future are presumed to be cheaper. In reality, renewable hydrogen from North Africa would remain highly competitive compared to hydrogen produced in the CESEC region if RES and electrolyser capacities in North Africa (or anywhere) where deployed gradually throughout the assessed period, as regional demand increases.
- By 2044, very little exports are observed from Italy to Austria. Instead, by 2045 Italy imports about 39 TWh, in addition to the 63 TWh produced locally to meet its demand. Germany's demand is increasingly supplied through Slovakia and Czechia, and to a lesser extent through Austria. Interestingly, by 2044 Hungary develops local production and by 2045 becomes a net exporter, reversing the direction of the Balkan corridor from Romania.

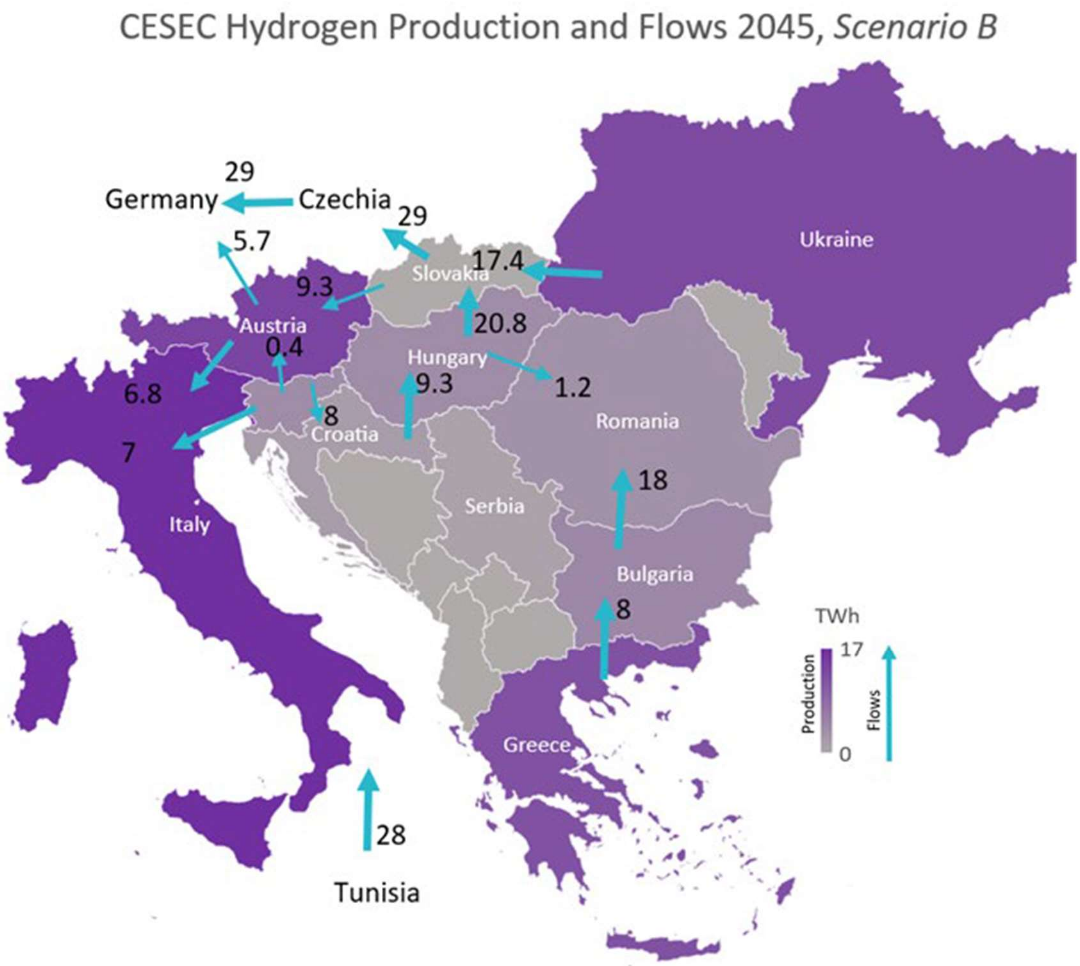
- In 2030, limited flows are observed from Greece to Bulgaria, as infrastructure is not yet built in transit countries (Romania and Hungary). The full Balkan corridor is assumed to materialise in 2034, with flows reaching Germany though Hungary and Austria. It is therefore assumed that transmission capacity will be deployed between Bulgaria and Romania in 2034, resulting in considerable flows in the range of 13-16 TWh between 2036-2041. This effectively leads to a substantial increase in hydrogen exports from Greece to Bulgaria, estimated at 7-10 TWh between 2036 and 2039.
- It would be also very plausible to assume that once the hydrogen corridor between Greece, Bulgaria, and Romania will emerge, the Energy Community countries may connect to it.
- By 2045 (Figure 34), Ukraine also becomes a net exporter by 2045, similar to Greece which supplies a sizeable amount (17.4 out of approx. 29 TWh) of flows to Germany through Slovakia.
- Under various sensitivity scenarios that have been implemented, it becomes evident that the quantity of hydrogen to be imported from North Africa is significantly influenced by several parameters, including the actual cost of renewable energy production in North Africa, which remains unknown at this stage, Italy's specific plans for deploying domestic electrolysers and renewable energy sources plants, as well as transportation costs and tariffs.
- It should be noted that with solid commercial arrangements between industrial consumers in Germany and hydrogen projects developers in North Africa, a substantial portion of German demand could be supplied via the SoutH2 corridor. This could result in German imports from the CESEC region exceeding 40%, particularly flows from North Africa to Germany via Italy and Austria.
- Another important finding is that due to hydrogen production's inherent seasonal profile, results showcase that pipeline volumes tend to flow into hydrogen storage during the period of high-RES production (and particularly PVs in late spring and summer), and out of storage during periods of low-RES production (winter). This seasonal flow is not fully depicted in the results as they illustrate only net annual flows. In this context, it should be also clarified that bi-directional flows leading to phenomenally low net annual flows do not necessarily imply limited utilisation of a transmission infrastructure. The important take-away point is that hydrogen production (and subsequently its price) will be highly seasonal, because of seasonality in supply, unlike natural gas that exhibits seasonality in demand. This annual effect will have a profound seasonal impact on hydrogen prices.
- The above insight is supplemented by the outcome of the model in building out hydrogen storage to accommodate for this seasonal effect. We note that an extension of this argument is reflected in built pipeline capacities that are used to accommodate high flows from production to storage in the summer, and from storage to demand in the winter.

Figure 33 Annual hydrogen cross-border flows and production in the CESEC region in 2030 under Scenario B – CESEC + Germany / North Africa



For a better visibility, detailed data regarding the different regional flows of hydrogen, for each year, under both model scenarios (A and B), can be found in Annex H: Hydrogen cross-border flows. Finally, an important general conclusion across both Scenarios is that, given that the timeframe of the analysis extends well beyond the ten-year period of the TSO development plans, there is a need for a greater number of projects to accommodate hydrogen flows that are either in the early stages of development or not yet planned.

Figure 34 Annual hydrogen cross-border flows and production in the CESEC region in 2045 under Scenario B – CESEC + Germany / North Africa



Additional RES capacities to meet hydrogen demand in the region

Both scenarios highlight significant potential for expanding RES deployment in the CESEC region. This is particularly promising as several countries are in the early stages of decarbonising their electricity generation capacities. As these countries transition away from fossil fuels, they have the opportunity to collaboratively plan the development of RES and hydrogen capacities, alongside the corresponding transmission networks. As explained in Section 2.6, the modelling work identifies, *inter alia*, the required national level electrolyser capacities to meet hydrogen demand across the CESEC region based on the most cost-optimal solutions.

Figure 35 and Figure 36 present additional RES capacities that are installed (as derived by the PLEXOS model in a cost-effective manner i.e. based on their levelised costs and capacity factors[247]), to meet the projected hydrogen demand in the region from 2030 to 2049 for each Member State or Energy Community Contracting Party. In order to satisfy the overall hydrogen needs, considerable electrolyser capacity is required, amounting to approx. 75 GW in Scenario A and 62 GW in Scenario B by 2045.

By 2050, Scenario B demonstrates a significant reduction compared to Scenario A in RES generation highlighting the impact of the hydrogen transmission from North Africa which can cover part of the CESEC

[247] Capacity factors for RES technologies utilised in the analysis are presented in Annex D: Capacity factors

region's demand. As a result, CESEC countries are adopting a more moderate approach to developing installed electrolyser capacity.

High installed RES/electrolyser capacities have considerable implications in terms of electricity grids planning, spatial planning for RES and other considerations. Moreover, they indicate that in the future hydrogen or hydrogen carrier terminals may be necessary.

Figure 35 Electrolyser installed capacity in CESEC 2030-2050 in the Scenario A – CESEC Regional

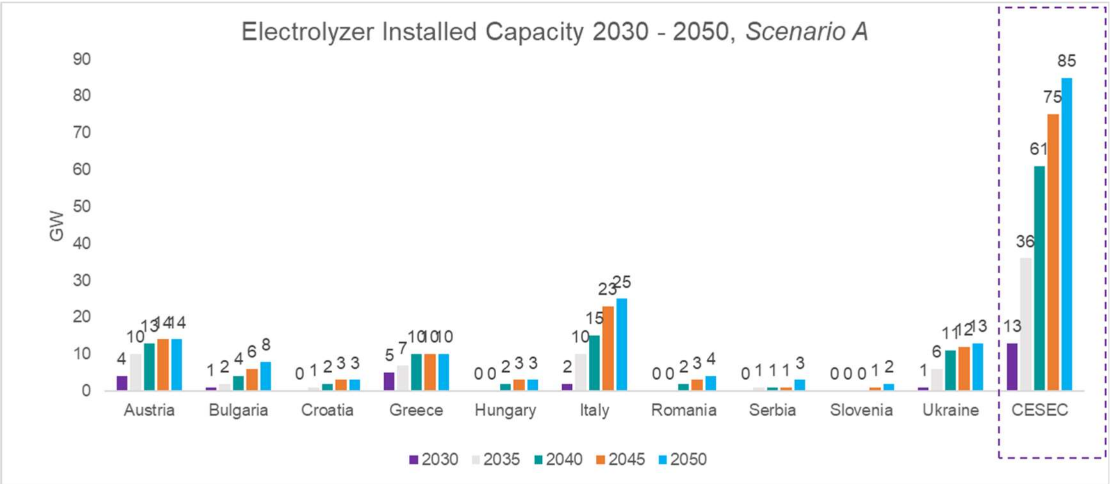


Figure 36 Electrolyser installed capacity in CESEC 2030-2050 Scenario B – CESEC Regional + Germany / North Africa

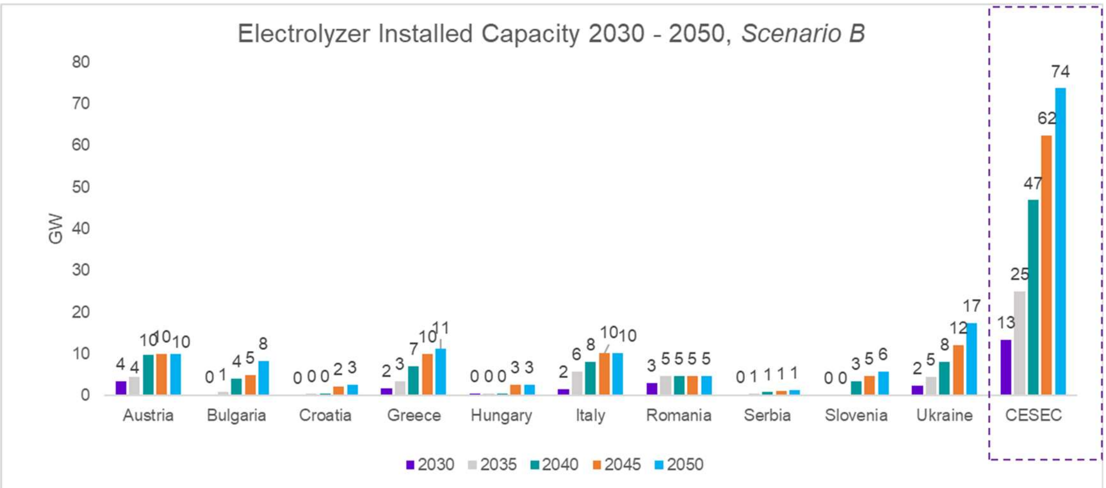


Figure 37 and Figure 38 illustrate the additional deployment of RES-electricity generation to meet electrolyser demand. In Scenario A, the largest RES production is observed in Ukraine to satisfy the substantial domestic demand, followed by Italy and Greece. However, in Scenario B, Italy substantially increases its RES electricity generation to meet rising demand, thereby gaining a larger share compared to Ukraine.

Figure 37 Additional total RES generation for each CESEC country until 2045 in the Scenario A

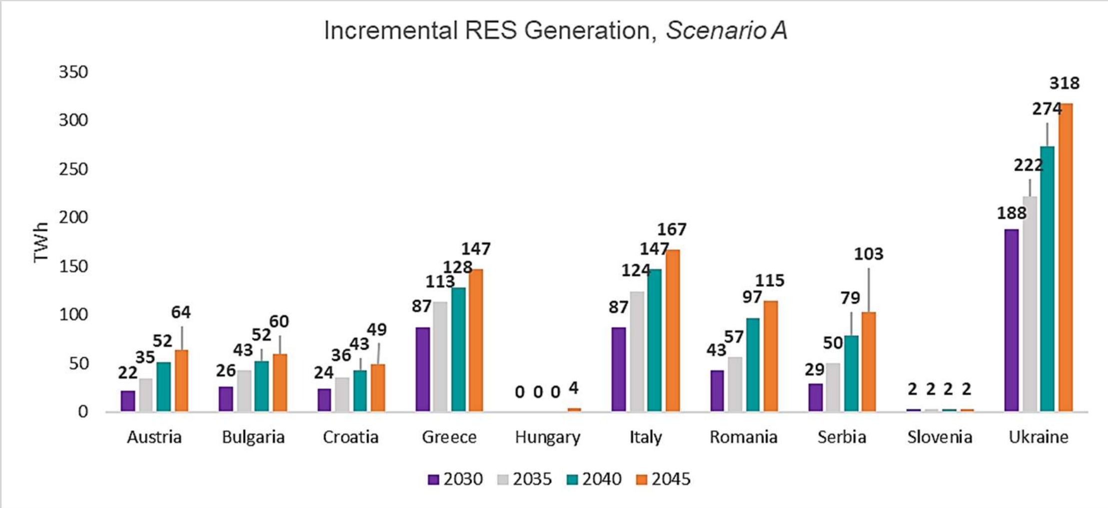
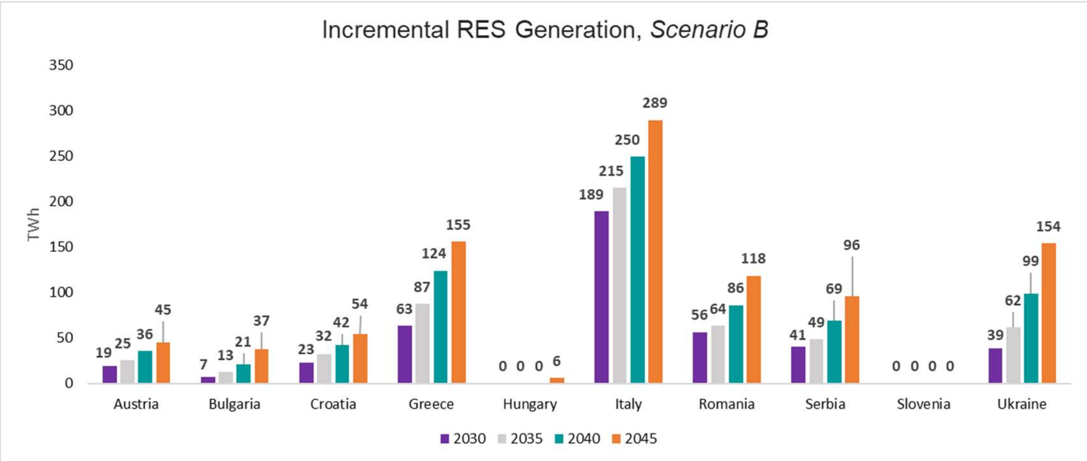


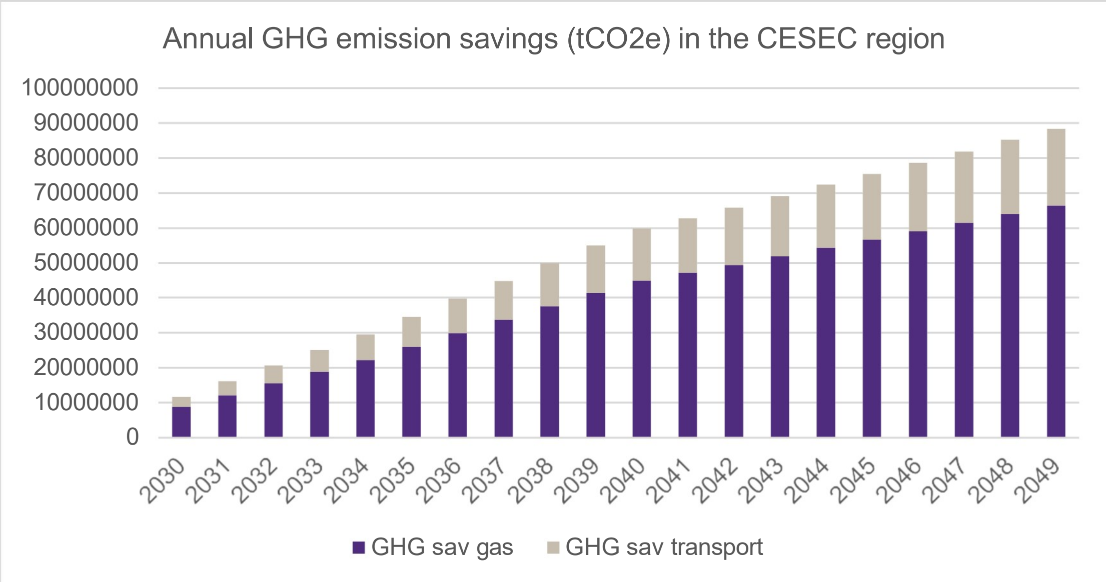
Figure 38 Additional total RES generation for each CESEC country until 2045 Scenario B



GHG emission savings in the CESEC region

Annual emission savings as a result of the substitution of natural gas and fossil fuels in the CESEC region (excluding Germany) in the industrial and transport sectors for the period 2030 to 2049 are presented in Figure 39, that are attributed solely to green hydrogen. The methodology for the calculation of emission savings is presented in Section 3.4.

Figure 39 Annual CHG savings due to the substitution of natural and fossil fuels in the CESEC region (in tCO_2e)



5.4 Overall adaptation needs for hydrogen transportation and related investment costs

As already highlighted, as of today infrastructure capable of accepting pure hydrogen does not exist in the CESEC region. Modelling analysis in Section 5.2.3 clearly indicates the necessity for large-scale cross-border infrastructure, which is a conclusion that aligns with the PCI/PMI process. The domestic market will be satisfied through the national transmission systems (new of repurposed) and for much smaller distances, by truck. Additionally, the construction of an extensive dedicated network, incorporating repurposed segments, will be required in the coming decades, presenting several technical challenges and the need for significant adaptations.

The preceding sections of Chapter 5 briefly addressed costs solely in the context of comparing the cost-effectiveness of the three modes of transporting pure hydrogen at a high level. This section evaluates the mid- to long-term infrastructure investments analysed in Section 5.2 and outlines their cost dimension. In general, the necessary investments include:

- Hydrogen pipelines (repurposing or building new).
- Components inherently linked to transmission pipelines, including compressors, metering stations, valves, and injection facilities.
- Hydrogen storage facilities.
- Facilities for receiving, storing, and regasifying liquefied hydrogen or hydrogen carriers.
- Smartening the grid[248] (i.e., digitalisation, reverse flow, chromatographs).

For the purposes of this exercise, publicly available sources have been taken into consideration. Table 9 summarises the envisaged adaptation and their respective costs. It is important to exercise caution with the identified costs, as they primarily as indicative of the investment's approximate magnitude.

Table 9 Infrastructure costs for the higher uptake of renewable hydrogen in transportation, reception and storage

Type of infrastructure	Adaptation need and description	Indicative cost(s)
Pipelines	Either repurposing existing natural gas pipelines or construction of new hydrogen dedicated ones. Most likely a combination of both options will be required to control costs and avoid stranded assets. However, repurposing is not always feasible and particularly in cases that there are no alternative routes for existing natural gas flows.	New pipeline CAPEX: 1.8 – 4.4 MEUR/km depending on the diameter [249] Repurposed pipeline CAPEX: 0.54 – 0.88 MEUR/km depending on the diameter [250]
Valves and seals	New valves and seals are needed due to hydrogen being a small molecule and prone to leak across the closure member or through the gaskets or packing of a common valve. Leakage can also occur if the wrong types of fittings are used to connect tubing or if the tubing or fitting materials are not hydrogen-compatible. In general, transmission pipelines include many valves along their length and their spacing depends on the location. Spacings typically range from 8-30 km	40 kEUR/km (if they are placed more than 15 km apart from each other)[251]
Compressor station	At any pressure, hydrogen carries less energy per volume than methane. This means that higher volumes	New compressor station CAPEX: 4 MEUR/MW[252]
or hydrogen carriers	responsible for the high CAPEX. Not likely to be required in the immediate future.	
Safety measures	Hydrogen is a small molecule compared to the gases that compose natural gas and, as such, the leakage risk is higher. Therefore, pipe connections in systems accommodating hydrogen should, whenever possible, be permanently welded or hard soldered because this ensures long lasting leak-proofness. This is especially true for hydrogen pipes running under the ground or in not easily accessible areas. It also burns with a nearly invisible flame, so special flame detectors are needed. A further type of safety measure it to place automatic fail-closed shutoff valves at critical points in the system so that it can be put in a safe state when a failure occurs. Hydrogen-compatible odorisation should also be foreseen.	n.a.
Reverse flow facilities	Reverse flow facilities are essentially a whole system which compresses the excess gas injected in the local distribution network and redirects it to the transmission network. The redirected gas is then sent to consumption zones located further away or to storage facilities. Occasionally, equipment to enable reverse flows from the distribution to the transmission level is found as part of investments in "smart gas grid".	50,000 EUR (pilot reverse flow in Ostiglia, Italy)[257]
Smart metering stations	Smart metering stations include smart gas meters, communication infrastructure, data management systems, remote monitoring systems and control, billing, and customer services, as well as security measures. They can automatically transfer information on inlet and outlet pressure, flow rate, gas composition and temperature and are designed to monitor and manage	Average CAPEX in Hungary: 96.11 EUR/metering point[258]

Type of infrastructure	Adaptation need and description	Indicative cost(s)
	the consumption of natural gas.	
Supervisory Control and Data Acquisition (SCADA) and Gas Management System (GMS) functions	Those two systems are complementary. SCADA is a data acquisition tool, upon which the GMS function is built and generates insights and notifications based on the data gathered. GMS provides operators with all the information needed to efficiently operate the gas grid.	5.5 MEUR[259]

Overall investment needs

The large-scale deployment of renewable hydrogen will require substantial investments in both the development of new dedicated networks and the repurposing of existing ones. According to the 1st PCI/PMI list:

- The cost associated with the SouthH2 corridor is reported to be 3.6 billion EUR[260], with approx. 75% of the CAPEX dedicated to the repurposing of existing midstream infrastructure.
- The investment in the internal hydrogen infrastructure in Greece leading to the Bulgarian border is estimated at 1 billion EUR[261], while the cost for developing the internal hydrogen infrastructure in Bulgaria towards the Greece border is approx. 860 million EUR[262].
- The repurposing of the pipeline in Ukraine (500 km pipeline) and construction of 2 compressor stations in Slovakia and repurposing of the pipeline in Czechia is estimated at approx. 90 mln EUR, 440 mln EUR and 120 mln EUR, respectively[263].

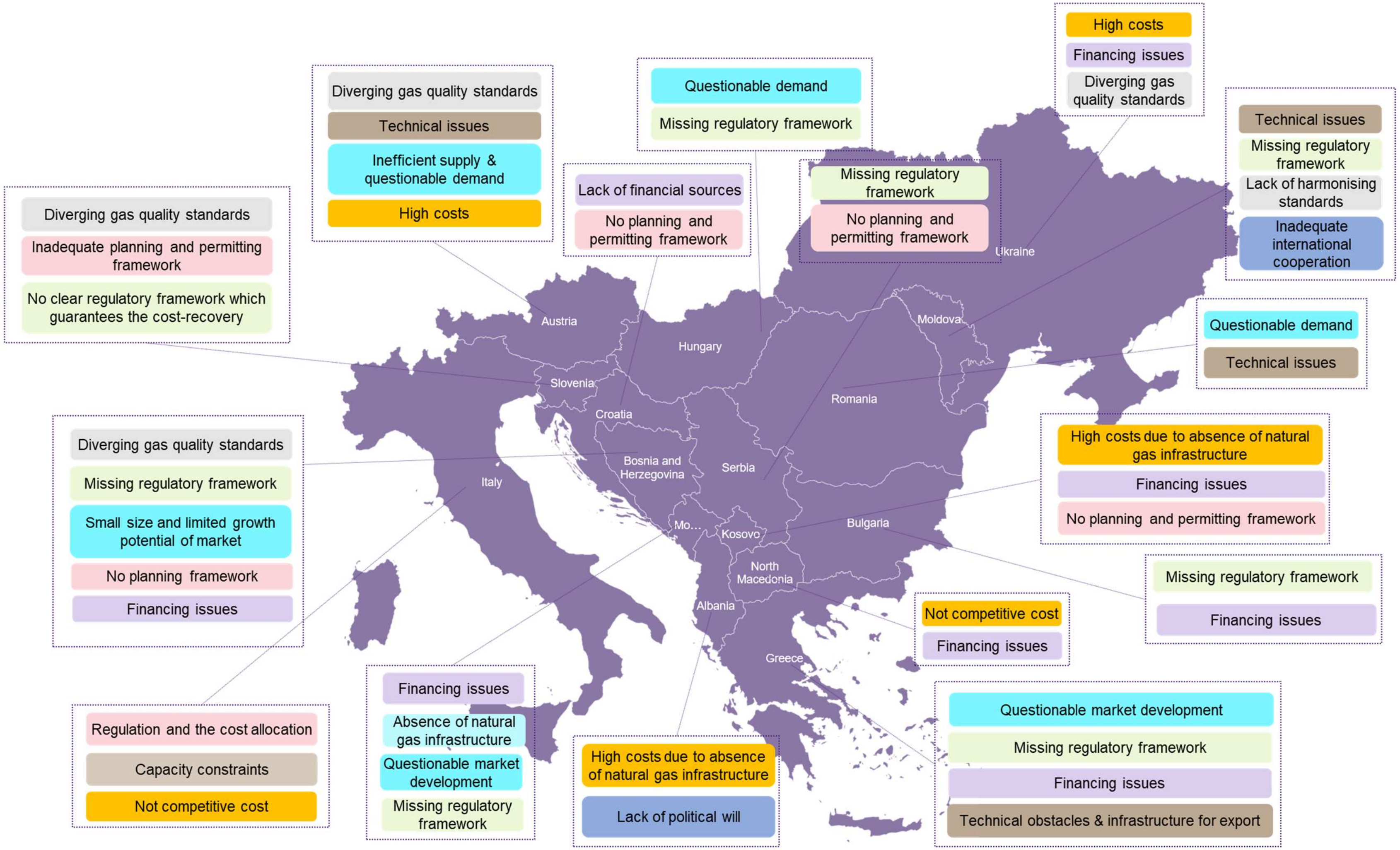
5.5 Challenges for infrastructure development for hydrogen and biomethane

The numerous projects proposed in the region by TSOs, DSOs, Storage Operators, and private actors of those (see Chapter 5.2) reflect the countries' commitment to the green transition. While willingness and intention are crucial, it should not be assumed that the transition from the fossil-based energy vectors to renewable ones, especially renewable hydrogen, is without significant challenges related to the development of infrastructure capable of accommodating these molecules. Challenges identified by various stakeholders during interviews pertain to policy, regulatory and technical aspects of transmitting, which are further elaborated in subsequent sections (Figure 40). It is important to note that while the study primarily focuses on infrastructure, it also discusses aspects related to supply and demand in market segments, where applicable.

[248] Smart grid investments is also relevant for enabling more efficient transportation of biomethane from local and decentralised location sites
[249] Gas for Climate: European Hydrogen Backbone, July 2023. Available at: https://ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf
[250] Gas for Climate: European Hydrogen Backbone, July 2023. Available at: https://ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf
[251] Gas for Climate: European Hydrogen Backbone, July 2023. Available at: https://ehb.eu/files/downloads/2020_European-Hydrogen-Backbone_Report.pdf
[252] Gas for Climate: European Hydrogen Backbone, July 2023. Available at: https://ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf
[253] Unit Investment Cost Indicators - Project Support to ACER Final report 14 June 2023 Final version
[254] https://www.ctc-n.org/sites/www.ctc-n.org/files/resources/hydrogen_injection_into_the_natural_gas_grid-_development_of_business_cases_for_fuel_cells_and_hydrogen_applications_for_regions_and_cities.pdf
[255] https://www.gie.eu/wp-content/uploads/filr/3517/Picturing%20the%20value%20of%20gas%20storage%20to%20the%20European%20hydrogen%20system_FINAL_140621.pdf
[256] Hydrogen Import Terminal: Providing insights in the cost of supply chain elements of various hydrogen carriers for the import of hydrogen, TUDelft (2019), retrieved here

[257] https://www.italgas.it/wp-content/uploads/sites/2/2022/06/2022-2028-Italgas-Strategic-Plan.pdf
[258] AF%20Mercados%20NTUA%20CBA%20Final%20Report%20June%2015_0.pdf (europa.eu)
[259] Transgaz (2022). Personal communication, 23 December

Figure 40 Challenges related to the hydrogen transmission in its native form according to the answers provided by stakeholders



[260] CESEC Ministerial Meeting, Athens, Greece, January 2023
[261] DESFA plans a €1bn hydrogen pipeline between Greece and Bulgaria | Enerdata
[262] TYNDP 2022 List of projects- update after adhoc collection.xlsx (live.com)
[263] Reported by Ukrainian, Slovakian and Czech TSOs during the PCI process

5.5.1 Policy challenges

The development of a coherent policy framework for the establishment of renewable and low-carbon gases market is crucial. However, the assessment indicated that not all CESEC countries have developed clear pathways, as reflected in their strategic documents, to foster the integration of renewable and low- carbon gases. As elaborated in Chapter 3, while the majority of EU countries in the region include these gases in their strategies, operational aspects like targets or forecasts per sector are often lacking.Moreover, with regards to biomethane, the decentralised biomethane production patterns create challenges for accommodating scattered volumes into limited injection points. In addition, difficulties in the supply chain related to ensuring stable and sufficient feedstock streams for large-scale plants impede the development of economies of scale. These difficulties have certain implications with regard to the allocation of grid connection costs (deep versus shallow approaches[264]) for biomethane costs, the reforming of the supply chains and potential regulatory interventions in the waste sectors and certain design elements of the support schemes. Thus, policies and regulatory frameworks under development should take into account these considerations.

5.5.2 Market challenges

Currently, the production of renewable hydrogen is more expensive than the production of conventional fossil-based hydrogen from natural gas or coal. The cost of fossil-based hydrogen primarily depends on the prices of fossil fuels used for its production, plus the ETS, which are subject to fluctuation and generally expected to increase in the medium- to long term, especially if the costs of GHG emissions are included. At the same time, the cost of renewable electricity and technological improvements of electrolysers are expected to decrease the levelised costs of hydrogen. In the short- to medium-term, dedicated financial support schemes can help in to bridge this cost gap, by lowering the costs of renewable and low-carbon gases, making them more affordable or attractive to off-takers. Thus, establishing security and de-risking hydrogen production and supply markets is critical in initially establishing a functioning market.

Focusing solely on infrastructure development, repurposing existing gas transmission networks or developing new, hydrogen-dedicated networks from scratch, represents investments with potentially slow capital recovery. This slow recovery is the consequence of anticipated delays in fully utilising the transmission network capacity due to limited production and/or off-take of hydrogen in the future, both of which are critical prerequisites for building transmission demand. Hence, infrastructure projects may require financial support as means to mitigate some of the risks associated with slow uptake. However, hydrogen infrastructure projects not linked with production and committed off-takers are viewed as risky and, consequently, commercial and development banks are hesitant to finance them.

The situation with biomethane is very similar as its production is more expensive than natural gas. On average, the biogas production facility is the most significant cost in the biomethane supply chain. Given the fact that biodigesters' technology is mature, and no major technological advancements are expected, a decrease in the production cost of biomethane from anaerobic digestion can be achieved through economies of scale and through the valorisation of by-products, i.e., biogenic CO_2 and bio-digestate.

5.5.3 Regulatory challenges

Until the publication of Green Deal and EU Hydrogen Strategy in 2020, hydrogen production was largely captive and, thus, no hydrogen market existed. The introduction of REPowerEU Action Plan in 2022 introduced hydrogen in the prevailing regulatory framework, which so-far was concerned only with natural gas. During the implementation of the study, significant steps progress was made towards establishing comprehensive and well-defined regulatory framework for hydrogen, culminating in the agreement on the

[264] A "shallow" connection involves the recovery of the costs of connection assets through an up-front connection charge, and the recovery of all reinforcement costs through use of system charges. This differs from a "deep" connection which involves the recovery of the total costs (or the largest part of them) that will be incurred as a result of connecting new load or production to the system, including all costs of network reinforcement, through an up-front connection charge.

Hydrogen and Decarbonised Gas Market Package by the two co-legislators at the end of 2023[265]. This legislative package is a key milestone in the EU's efforts to create a viable hydrogen market and facilitate the transition to decarbonised gases[266]. For these provisions to have a practical impact, it is crucial that they are transposed into the national legislation, through both primary and secondary legislations, starting with EU Member States and subsequently by the Energy Community Contracting Parties of all CESEC countries.

The surveys and interviews conducted as part of this study revealed a widespread concern among stakeholders regarding the absence of a clear and robust regulatory framework for hydrogen. This concern is understandable given that the regulatory landscape for hydrogen was still under development at the EU level that time.

5.5.4 Technical challenges

The industry is still in the process of acquiring practical experience with pipeline network and overall infrastructure designed for pure hydrogen. Hydrogen, being a smaller molecule compared to methane in natural gas, can penetrate materials that would be impermeable to other gases. Its highly flammable nature also poses significant safety concerns as it can cause fires and explosions if not handled properly. Due to its small size, hydrogen could diffuse into the metal of damaged pipe, which would then brittle (i.e., steel embrittlement) and lead to damaged pipelines. In addition to those technical constraints, the lower volumetric energy density of hydrogen compared to natural gas (3.5 kWh/m^3 vs. 11.4 kWh/m^3) necessitates an increased flow velocity of hydrogen in the network to deliver the same amount of energy/capacity. This increase in flows requires the design of high-pressure, hydrogen-compatible compressors (either centrifugal or reciprocating).

Hydrogen infrastructure also includes underground storage facilities (UGS). Very limited experience is gained so-far on the repurposing of existing natural gas UGS, focusing exclusively on salt caverns. Specifically, hydrogen has successfully been stored in only three different salt caverns at a global level, demonstrating that this type of UGS facility may represent the most suitable solution for large-scale pure hydrogen storage. The downside is their limited geographical availability across Europe and their insufficient working gas capacity. Consequently, depleted fields and aquifer storage sites also need to be repurposed for hydrogen to meet future hydrogen storage needs[267]. Technical challenge associated with hydrogen storage in porous media (i.e., depleted fields and aquifer sites) is the expected difficulty of those sites to contain it due to the molecule's higher compressibility factor, diffusivity, and lower viscosity, compared to natural gas.

When pure hydrogen needs to be transmitted over long distances (i.e., above 1,500 km) and in substantial volumes, or to/from countries not connected to the EU by pipeline, transportation via ships will eventually be considered. In this case, hydrogen is handled in its liquid form (LH_2), analogous to LNG. Thus, transmission of LH_2 requires hydrogen-dedicated infrastructure, consisting of liquefaction plants, specialised ships, and terminals (onshore or FSRU[268]) to liquify, transport, unload, store, regasify and distribute the renewable molecule. When considering storage LH_2, it is noted that only limited experience can be drawn, as there is a small number of liquid hydrogen tanks existing today with capacity substantially lower than for LNG. Compared to LNG, a key challenge is the higher cooling requirements for LH_2 (i.e., -253°C vs -160°C), which dictate the use of different thermal insulation materials, as well as specialised designs (i.e., spherical design with double walls, thermally insulated with a vacuum). Due to the very low boiling temperature, the risk for boil-off is much higher compared to LNG and managing to reduce it presence a significant challenge[269]. A further technical challenge associated with the transmission of hydrogen in its liquid form is

[265] https://www.consilium.europa.eu/en/press/press-releases/2023/12/08/gas-package-council-and-parliament-reach-deal-on-future-hydrogen-and-gas-market/
[266] https://data.consilium.europa.eu/doc/document/ST-16522-2023-INIT/en/pdf
[267] https://www.gie.eu/wp-content/uploads/filr/3517/Picturing%20the%20value%20of%20gas%20storage%20to%20the%20European%20hydrogen%20system_FINAL_140621.pdf
[268] Floating Storage and Regasification Units

the high energy demand for the liquefaction process, which is estimated to be 30-36% of the fuel energy content[270].

Irrespective of the state of hydrogen and the type of infrastructure, the pending safety regulations for using LH_2 as fuel and the absence of a robust system of standards and certification constitute additional technical challenges[271]. Standardisation of the so-far established Guarantees of origin (GO)[272] for renewable and low-carbon gases is pending and, thus, national GOs cannot be traded across borders.

The aforementioned challenges concern pure hydrogen. Hydrogen blends (to the extent promoted permissible by EU legislation and promoted by CESEC countries) are feasible to a certain degree and in selected countries, but challenges still exist. Those include the potential need for de-blending, varying standards, different energy contents, blend instability and absence of facilities such as reception, storage and regasification or decompression facilities. These challenges also constitute inherent reasons for which blending only represents a temporary solution, which not only comes at a cost, but can also result in lock-ins and stranded assets.

When considering infrastructure development to accommodate biomethane, reverse flow possibility from the distribution network to the transmission system will become increasingly important. This is the case when the injected quantities of biomethane potentially surpass the demand at the distribution level. Therefore, the installation of reverse flow facilities, prioritising gas grid injection for biomethane and increasing cooperation between transmission/distribution adjacent gas grid Operators are crucial and should be studied and prioritised by TSO/DSOs.

An additional technical challenge with regards to biomethane is the inherent oxygen concentration, which -if pronounced[273]- can cause issues like corrosion, bacterial growth, and sulphur build-up. Thus, countries with strict oxygen acceptance levels might need to adjust their gas quality standards to more reasonable levels. This is important especially on the transmission and storage side to harmonise the quality standards across the overall region and facilitate cross-border trade.

5.6 Criteria and indicators for the identification and assessment of key cross – border infrastructure projects

The revised TEN-E regulation sets criteria for projects to be recognised as Projects of Common Interest (PCI) and Projects of Mutual Interest, which are essential for achieving the European Union's energy policy and objectives. For the assessment of candidate projects, Article 11(8) of the revised TEN-E Regulation states that: *"For projects falling under the energy infrastructure categories set out in point (1)(c) and (e) and in points (2), (4) and (5) of Annex II, the Commission shall ensure the development of methodologies for a harmonised energy system-wide cost-benefit analysis at Union level. Those methodologies shall be compatible in terms of benefits and costs with the methodologies developed by the ENTSO for Electricity and the ENTSO for Gas. The Agency, with the support of national regulatory authorities, shall promote the consistency of those methodologies with the methodologies elaborated by ENTSO for Electricity and the ENTSO for Gas. The methodologies shall be developed in a transparent manner, including extensive consultation of Member States and of all relevant stakeholders."* In line with the legal requirements set out

[269] Riemer, M.; Schreiner, F.; Wachsmuth., J. (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility und Economic Considerations. Karlsruhe: Fraunhofer Institute for Systems and Innovation Research ISI
[270] Riemer, M.; Schreiner, F.; Wachsmuth., J. (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility und Economic Considerations. Karlsruhe: Fraunhofer Institute for Systems and Innovation Research ISI
[271] Riemer, M.; Schreiner, F.; Wachsmuth., J. (2022): Conversion of LNG Terminals for Liquid Hydrogen or Ammonia. Analysis of Technical Feasibility und Economic Considerations. Karlsruhe: Fraunhofer Institute for Systems and Innovation Research ISI
[272] A system analogous to what is being established in electricity that differentiates the renewable molecules in the gas system from the fossil-based molecules
[273] Depends on the feedstock

in Article 11(8) of the TEN-E Regulation, CBA methodologies for candidate projects in these categories have been developed by the JRC[274].

The study has identified key criteria for the possible selection of infrastructure projects of cross-border relevance for the CESEC region, which could be instrumental in integrating hydrogen and biomethane into the CESEC region. The criteria might be used by the CESEC High-Level Group to facilitate the group's future discussions on the selection of infrastructure projects to be included in the CESEC Action Plan on gases, whose realisation would be subject to the CESEC High-Level Group's monitoring.

The present section aims at highlighting primarily qualitative aspects with regards to the assessment of cross-border projects within the CESEC Group. Specifically, emphasis is placed on dimensions related to maturity, robustness of the analysis, sizing of the infrastructure and avoidance of lock-ins. The proposed screening aspects are illustrated in Table 10.

Table 10 Potential criteria & indicators for the screening of cross-border projects submitted for the CESEC Action Plan on Gases

TEN-E Criterion	Screening aspect	Proposed Screening Indicator	Nature of assessment (Qualitative / Quantitative)
Not addressed within TEN-E	Level of Maturity	• Existence of studies (CBA, Market study, feasibility study, FEED studies) • Projected time for Commercial Operation	Qualitative
Not addressed within TEN-E	Robustness of supply & demand assessment	• Number and type of studies • Data Source Reliability	Qualitative
Not addressed within TEN-E	Sizing of the infrastructure against the demand	• Committed / Expected utilisation rate of the asset as reflected by studies, market tests, etc. • Infrastructure Scalability	Qualitative
Not addressed within TEN-E	Future proofing (non-lock-in effects)	• Flexibility for future technology integration • Compatibility with future market standards	Qualitative
Sustainability	Sustainability	• Variation of GHG emissions • Variation of non-GHG emissions	Quantitative
Specific Criteria: Security of Supply and Flexibility	Security of supply	• Fossil-fuel import dependency reduction • Supply route diversification	Quantitative
Specific Criteria: Market integration	Contribution in sector coupling	• Curtailment reduction	Quantitative
Cross-Border Impact	Coupling of supply and demand centres/countries	• Level of interconnection • Supply sources diversification	Quantitative
Cost-Benefit Analysis	Cost-efficiency	• CAPEX, OPEX • Levelised Cost of Transport (LCOT)	Quantitative

274 https://energy.ec.europa.eu/system/files/2022-10/20221007_DRAFT_METHODOLOGY_CBA_ELECTROLYSERS.pdf

TEN-E Criterion	Screening aspect	Proposed Screening Indicator	Nature of assessment (Qualitative / Quantitative)
Specific Criteria: Market integration	Market integration	• Number of coupled markets • Number of countries involved or impacted	Quantitative
Cost-Benefit Analysis	Socioeconomic welfare	• Monetized benefits • Impact on prices	Quantitative

6 Conclusions and way forward

6.1 Conclusions

Demand and production patterns

With regards to the current state of play, no CESEC country produces renewable or low-carbon hydrogen in considerable quantities, while captive fossil-based hydrogen production is reported in various countries. Refineries account for the highest hydrogen demand (50%), followed by the ammonia industry (30%)[275], with the remainder being used for methanol production and other chemical industry purposes. Fossil- based hydrogen production is highest in Italy, with 25 TWh/y, followed by Greece (13 TWh/y) and Hungary (approx.7,5 TWh). Very little renewable hydrogen production takes place in Austria, Hungary, Greece, and Slovenia due to small-scale projects that are either operational or in the demonstration phase.

Moreover, none of the CESEC countries exports hydrogen to neighbouring states, as the indigenous fossil production is used to meet local demand. Nevertheless, several hydrogen production projects are in the development stage and are expected to supply more than 30 TWh by 2030, with announced projects concentrated in Greece, Italy, Austria, Romania, and Slovenia.

According to the NECPs of the CESEC countries, renewable and low-carbon hydrogen is anticipated to gradually replace fossil-based hydrogen in industrial applications in the medium term. Long-term uses are identified in the production of methanol and synthetic fuels, and as a coal replacement in iron production. The transport sector is also prioritised across most CESEC countries.

With regard to biomethane, publicly available data for the CESEC region are scarce. Italy is the frontrunner in the production of biomethane, followed by Austria and Hungary. Since 2023, biomethane is also produced in Ukraine. In analogy to the overall limited production in the CESEC region, most of the countries assessed (Albania, Bosnia and Herzegovina, Bulgaria, Kosovo, Moldova, Montenegro, North Macedonia, Romania, Serbia) do not include strategic targets or policies to promote the use of biomethane.

Infrastructure readiness

In general, the CESEC region lacks infrastructure capable of accepting pure hydrogen. TSOs and Storage Operators in several countries within the region have started conducting evaluations of their infrastructure components through laboratory testing to assess the compatibility with hydrogen blends and pure hydrogen. However, progress varies significantly among the countries examined.

Italy, Austria and Hungary are more advanced in assessing the compatibility of their networks for hydrogen.

Austria, Italy, Hungary and Ukraine are also the only countries in the CESEC region that have made significant progress in integrating biomethane into their national system. They not only produce biomethane but also directly inject it into their existing gas transmission and distribution systems.

Cross-border flows and necessity for cross-border hydrogen infrastructure

According to the NECPs and projects submitted under the TEN-E framework, CESEC countries aim to primarily meet their demand by 2030 through domestic supply. Beyond this period, the development of capital-intensive cross-border hydrogen pipelines might be necessary potentially in combination with repurposing of existing assets, if market demand is substantially increased. The findings of the modelling analysis conducted through PLEXOS align in general with the results of the PCI/PMI process with regards to future cross-border flows and the need for respective transmission infrastructures.

275 https://observatory.clean-hydrogen.europa.eu/sites/default/files/2023-05/Chapter-2-FCHO-Market-2022-Final.pdf

Key insights from the analysis reveal:

- In the Scenario A – CESEC Regional in 2030, local hydrogen demand does not appear to be sufficient to justify the development of cross-border transportation corridors either through Tunisia/Italy or from Greece toward Central-Eastern Europe. However, the comparison of the two scenarios indicates that demand in Germany is a catalyst for large scale cross-border infrastructures and that eventual needs of Germany will partly determine the sizing of the proposed infrastructures in the CESEC region.
- Eventually three corridors emerge with high degree of certainty, i.e., imports from Algeria and Tunisia to Italy and onwards to Germany, a hydrogen corridor initiating from Greece through Bulgaria and Romania toward Central-Eastern Europe and a corridor originating from Ukraine to Germany through Slovakia and Czech Republic or alternatively through Slovakia and Austria.
- It would be also very plausible to assume that in the hydrogen corridor that will emerge between Greece, Bulgaria, Romania and Central-Eastern Europe, the Energy Community countries such as Serbia, North Macedonia, Bosnia and Herzegovina may connect, assuming repurposing of existing assets and/or utilisation of projects that were originally designed for natural gas.
- The outcome of the hydrogen origination to meet high demand in Italy and Germany largely depends on assumptions regarding its cost at the entry point in South Italy from Tunisia (and other non-techno-economic aspects such as political stability in Ukraine). In this context, a substitution effect is observed when considering the transmission from Tunisia (Scenario B) where RES infrastructure that are not built in the CESEC region are partly replaced by RES built in North Africa where greater RES capacity factors are assumed to produce hydrogen to meet demand in the CESEC region.
- Another notable observation is that with solid commercial arrangements between industrial consumers in Germany and developers of hydrogen projects in North Africa, a significant portion of German demand can be met through the Italian-Austrian corridor. This would inevitably lead to German imports from the CESEC region increasing beyond 40% with flows from North Africa to Germany particularly rising.
- Overall, across the two scenarios, it is observed that there is a huge potential for further expanding the RES build-out in the CESEC region. As the countries move away from fossil fuels, they have the prospect of collectively planning RES and hydrogen capacity development, as well as the development of corresponding transmission networks. Finally, given that the timeframe of the analysis extends well beyond the ten-year period of the TSO network development plans, there is a need for a greater number of projects to accommodate hydrogen flows that are either immature or not even on planning stage yet.
- To satisfy the overall hydrogen needs, considerable electrolyser capacity is required to be developed in the CESEC region, amounting to approx. 75 GW in Scenario A and 62 GW in Scenario B until 2045. Under Scenario B significantly less RES generation capacity is required for electrolyser needs, underlining the impact of the hydrogen transported from North Africa at lower costs, which is able to cover part of CESEC's demand. Thus, CESEC countries follow a more moderate approach on the development of electrolyser installations on their ground.
- Considering the NECP targets for 2030 and the data communicated during the PCI/PMI process needs, it is estimated that renewable hydrogen in the CESEC region (excluding consumption in Germany) can displace approx. annually 54 TWh of natural gas in industry and diesel (for the transport sector) in 2030 and approx. 411 TWh in 2050, if all hydrogen produced is renewable.

6.2 Recommendations

Based on the main findings of the study, a series of actionable recommendations are formulated to facilitate the cost-effective uptake of renewable and low-carbon gases in the CESEC.

6.2.1 Policy development

- **Ensure that the final updated National Energy and Climate Plans include clear strategies for deploying renewable and low-carbon gases. These should include clear pathways for both the development and integration of these gases**, including the adoption of specific Hydrogen and Biomethane Strategies and Roadmaps. This approach is vital for establishing a well-defined projection of future demand. The aim is to ensure that these strategies comprehensively cover all types of renewable and low-carbon gases and all end-sectors simultaneously.
- **Promote renewable and low-carbon gases, stronger national support and de-risking need to be put in place to foster a developing market across the entire region.** While some CESEC countries, such as Italy and Austria, have implemented support schemes for the production of renewable hydrogen and biomethane, others are still contemplating the optimum approach. Any support instruments need to be carefully designed. These may include investment grants, operating aid, quotas, Contracts for Difference (CfDs), quota obligations, tax incentives, alleviation from grid connection costs, etc. Over the past few years, many EU Member States have established dedicated support schemes for biomethane and renewable hydrogen in the form of CAPEX or OPEX aid. It is particularly recommended to utilise the services of the European Hydrogen Bank for the support of renewable hydrogen projects, which is an already an established and well-functioning mechanism. The experiences from these support schemes should be considered in the preparation of corresponding support schemes for other countries in the CESEC region.
- **Promotion of integrated sector planning is important**. Align the planning and deployment of gas, electricity, hydrogen (and heat where applicable) networks to achieve synergies, reduce redundancy and the probability of stranded assets. This can be accomplished through the development of joint infrastructure scenarios included in the context of network development plans, allowing for a more comprehensive approach to resource allocation and system design, ultimately leading to a more energy-efficient network operation. This process will be further facilitated by the respective provisions for the European Network of Network Operators for Hydrogen (ENNOH).
- **Regional cooperation should be further fostered through the CESEC High-Level Group.** Given that more effective progress may be achieved through a regional approach, network operators and CESEC countries should use the CESEC framework to promote collaboration and monitor the effectiveness of the network planning and development at regional level. The High-Level Group may support various countries which have not yet made tangible progress in integrating renewable and low-carbon gases due to different supply and demand patterns, limited technical and institutional capacities, operational readiness, etc. Therefore, it is crucial for all involved CESEC stakeholders to intensify their efforts to enhance regional cooperation, focusing on the planning of infrastructure and capacity building activities.
- **Location optimisation for renewable and low-carbon production facilities is crucial.** The location of hydrogen production facilities (electrolysers) should be optimised, considering factors such as proximity to renewable energy generating assets (and thus grid availability), and water availability. This could be aligned or even integrated in the renewable acceleration areas/plans, according to the provisions of the revised Renewable Energy Directive. Similarly, for biomethane, the regulatory framework should take into account logistical considerations, the supply of feedstock and proximity to the gas grids to minimise the gas grid connection costs.

- **Intensify efforts to develop functioning markets.** Systematic differences exist between EU and EnC countries, particularly in terms of maturity of current RES/electricity markets, natural gas markets, institutional and regulatory frameworks, as well as standardisation of technical aspects (e.g., oxygen levels in biomethane). It is therefore suggested that efforts are intensified to further promote energy markets development, integration and deployment of renewable energy sources for hydrogen production.
- **Simplify the licensing processes for both hydrogen and biomethane plants.** Permitting and authorisation processes in certain countries are extremely lengthy and bureaucratic and constitute obstacles against the speed-up of their establishment and operation, while ensuring the highest level of operational safety. The transposition of REDIII will contribute towards this direction.

6.2.2 Market context

- **With regards to the demand side, it is crucial to focus on market sectors that have limited alternatives for decarbonisation** and map the ability of the end users to run on hydrogen through testing. Moreover, funds need to be mobilised for the adaptation of end use applications for hydrogen use, e.g., gas turbines, industrial boilers, process heaters, etc. Emphasis should also be placed on industrial clusters/hydrogen valleys that combine production and/or and use of renewable or low-carbon hydrogen.
- The type and location of available feedstock determines the potential for biomethane production in each country. Therefore, **mapping out sustainable feedstock opportunities** at the national level is essential.
- **To overcome the 'not in my backyard' syndrome**, countries could implement public education initiatives and engage stakeholders to enhance awareness and understanding of the benefits of biomethane and renewable hydrogen, potentially leading to broader acceptance and use.

6.2.3 Regulatory framework

- **CESEC countries should rapidly adopt the necessary primary and secondary regulatory framework**, including the implementation/transposition of the EU Hydrogen and Decarbonised Gas Market Package, resolution and standardisation of gas quality issues, methodologies for the calculation of tariffs, connection costs, etc.
- NRAs will have a prominent role in all aspects of the market development of renewable and low-carbon gases. Those may regard the approval of hydrogen or natural gas NDPs of TSOs, the assessment of hydrogen infrastructure projects, the transfer of regulated assets for repurposing, the calculation of network access tariffs of hydrogen network costs, and the approval of quality standards. Respectively, for biomethane, regulatory authorities will need to be involved in the amendment and approval of Codes and technical standards, assessment of projects such as reverse flow from Transmission to Distribution, allocation of costs for grid connection. Finally**, NRAs will need to be heavily involved in the early stage of cross-border planning and discuss regional issues with focus on regulatory framework development**, coordination, and harmonisation.
- The **institutional setup, especially concerning the hydrogen market and the assignment of roles to different entities** is a crucial policy and regulatory matter.

6.2.4 Infrastructure development

- The highest potential for cost-effective hydrogen generation is located in the southern part of the CESEC region (Italy, Greece) and in North Africa (Algeria, Tunisia), due to abundant photovoltaic resources. Major demand centres are located in Italy, Austria, and Germany, the latter lying at the borders of the CESEC region. Continuous analysis **in the coming years is essential to** better identify **production and consumption centres and** to minimise **uncertainties concerning the timing** for **deploying cross-border infrastructure.**

- To achieve the hydrogen targets, the deployment of more than 65 GW of electrolysers is required, excluding imports from Africa. At the national level, this necessitates a focused priority **on hydrogen-related RES plants given the constrains on available electrical capacity or the development of new electricity transmission infrastructure.** Additionally, spatial planning for electrolyser plants, in conjunction with RES resources (either PV or wind), is crucial to avoid electricity grid bottlenecks and congestion.
- Given the high costs associated with developing new infrastructure or repurposing existing infrastructure, it is vital for the CESEC countries and especially for the TSOs to prioritise carefully projects for realisation due to limited financial resources. Strategies should focus on **no-regret approaches**, such as careful planning to avoid creating stranded assets.
- Moreover, **TSOs should initiate market tests with adjacent TSOs** to verify commercial interest for hydrogen transmission projects and determine which flagships projects might be needed in the first phase of market development.
- Respective TSOs should **continue their analysis with tests and simulations on their networks' readiness to transport pure hydrogen**.
- **To mitigate seasonality demand issues and address the stochastic nature of RES, large scale hydrogen storage solutions** will become increasingly important as the quantities of hydrogen production rise. Further assessment of storage technologies and solutions, as well as R&D activities and pilot projects exploring the suitability of salt caverns, rock caverns, depleted fields and saline aquifers to store hydrogen are necessary.
- Countries with stringent oxygen acceptance levels **may need to re-adapt their gas quality standards** especially on the transmission and storage side in order to harmonise the quality standards across the region and facilitate cross-border trade.
- Efforts should be dedicated to setting **harmonised technical standards to bridge standardisation gaps**. This will ensure uniform standards across borders/interconnection points and facilitate cross-border trade.
- Assessments and potentially new projects are essential to determine if the production of renewable gases at the distribution level surpasses demand, which could necessitate a **reverse flow to enable transmission level users to access the surplus.** In this context, the relevant TSOs and DSOs should start discussions on how to optimally utilise the smart gas grid thematic area under the TEN-E framework. Such cooperation could lead to the creation of reverse flow capabilities from the distribution to the transmission level, enhance the efficiency of their gas networks, and improve the integration of renewable and low-carbon gases.

Annex A: EU Taxonomy – Technical screening criteria

Hydrogen-related economic activities in the EU Taxonomy Climate Delegated Act[276]	Substantial contribution to climate change mitigation
Manufacture of equipment for the production and use of hydrogen	The economic activity manufactures equipment for the production of hydrogen compliant with the Technical Screening Criteria (below) and equipment for the use of hydrogen.
Manufacture of hydrogen and hydrogen-based synthetic fuels	The activity complies with the life-cycle GHG emissions savings requirement of 73.4% for hydrogen (resulting in life-cycle GHG emissions lower than 3tCO2e/tH2) and 70% for hydrogen-based synthetic fuels relative to a fossil fuel comparator of 94g CO2e/MJ in analogy to the approach set out in Article 25(2) of and Annex V to Directive (EU) 2018/2001. Life-cycle GHG emissions savings are calculated using the methodology referred to in Article 28(5) of Directive (EU) 2018/2001 or, alternatively, using ISO 14067:2018 or ISO 14064-1:2018. Quantified life-cycle GHG emission savings are verified in line with Article 30 of Directive (EU) 2018/2001 where applicable, or by an independent third party. Where the CO_2 that would otherwise be emitted from the manufacturing process is captured for the purpose of underground storage, the CO_2 is transported and stored underground, in accordance with the technical screening criteria defined in the Delegated Act for the corresponding economic activities.
Transmission and distribution/transport networks for renewable and low-carbon gases[277]	The activity consists in one of the following: Construction or operation of new transmission and distribution networks dedicated to hydrogen or other low-carbon gases. Conversion/repurposing of existing natural gas networks to 100 % hydrogen. Retrofit of gas transmission and distribution networks that enables the integration of hydrogen and other low-carbon gases in the network, including any gas transmission or distribution network

[276] Commission Delegated Regulation (EU) 2021/2139

[277] Conversion, repurposing or retrofit of gas networks for the transmission and distribution of renewable and low-carbon gases. Construction or operation of transmission and distribution pipelines dedicated to the transport of hydrogen or other low-carbon gases.

Hydrogen-related economic activities in the EU Taxonomy Climate Delegated Act[276]	Substantial contribution to climate change mitigation
	activity that enables the increase of the blend of hydrogen or other low-carbon gasses in the gas system. The activity includes leak detection and repair of existing gas pipelines and other network elements to reduce methane leakage
Storage of hydrogen	The activity is one of the following: Construction of hydrogen storage facilities Conversion of existing underground gas storage facilities into storage facilities dedicated to hydrogen-storage Operation of hydrogen storage facilities where hydrogen stored in the facility meets the criteria for manufacture of hydrogen as above

Source: Taxonomy Climate Delegated Act available at: http://data.europa.eu/eli/reg_del/2021/2139/oj

Annex B: Survey Questions

<table>
<tr><th>Stakeholder type</th><th>Questions</th></tr>
<tr><td>TSOs</td><td>
Are you directly or indirectly involved in the biomethane or green or fossil-based hydrogen with abatement business?
How many of the operating biogas plants have upgrading to biomethane and are connected to the grid? Which is the total injection volume (bcm/y)?
How many of the operating biogas plants have upgrading to biomethane with no connection to the grid? Which is the total injection volume (bcm/y)?
What is the current biogas capacity installed (MW) in the country?
What is the current overall production of biogas and biomethane (bcm/y) in the country?
What is the current renewable hydrogen capacity installed (MW) in the country?
What is the current overall production of green and other colours of hydrogen (bcm/y) in the country?
Are you aware of key hydrogen or biomethane generation projects promoted (IPCEIs, major projects promoted by market players, utilities, etc.)?
How many hydrogen liquefaction facilities are there in the country?
How many liquid hydrogen gasification facilities are there in the country?
How many facilities for hydrogen conversion into a higher density chemical, such as ammonia, are there in the country?
How many facilities for recovering hydrogen from a higher density chemical, such as ammonia, are there in country and how much are planned for 2030?
How many anaerobic biodigesters are planned to become operational by 2030?
Are there any FSRUs/LNG terminals and gas storage facilities in the country and can accommodate hydrogen? If yes, up to what percentages and of what is the size? If no, can they cost-effectively be repurposed for the dedicated storage of hydrogen?
Are there gas storage facilities in the country and can they accommodate biomethane? If yes, up to what percentages?
Which are the currently established cross-border flows of natural gas that your country participates in? Name the pipelines crossing the country and facilitating the import of natural gas, as well as their entry and exit capacities.
Give the quantities (bcm/y) of imported natural gas, renewable hydrogen (if any) and biomethane (if any), as well as the involved pipeline.
Please prioritise the criteria that should be applied for the identification and assessment of key cross – border infrastructure projects.
Are there any hydrogen-dedicated networks in your country in operation?
Are the hydrogen-dedicated networks part of the TSO's regulated asset base?
Is it possible to inject H2 directly in the gas transmission network or is it a "premix" necessary to inject a H2 blend within certain limits, and which are those?
Are you participating in any regional initiatives/coordinating with other TSOs for planning and cross-border -issues?
Which is the total length (km) of the national pipeline transmission system?
As a TSO, what is the current maximum hydrogen concentration accepted in the natural gas transmission network?
Which is the main justification to set up such a hydrogen limit in terms of gas quality requirements at transmission level?
</td></tr>
</table>

	• What are your plans regarding retrofitting of existing infrastructure and construction of hydrogen-ready network in parallel? • As a TSO, are you aware of any incentives in your country of operation to develop projects for hydrogen injection into the gas transmission system? • As a TSO, do you have a hydrogen blending target? Please specify in (% vol.) and target year. • As of today, are there any cross-border flows of renewable gases (green or fossil-based hydrogen with abatement, biomethane)? If yes, what are the flows, the entry and exit capacities? • Is there a hydrogen limit for cross-border interconnection points (i.e. is it possible to import/ export gas with H2 content)? If yes, what is the limit? (please cross) • Which are the hydrogen blends (%) that each of the components comprising the national gas transmission system can accommodate? • How many projects are included in your latest TYNDP that promote renewable hydrogen via repurposing existing gas infrastructure or developing new hydrogen-dedicated infrastructure? Please mention the projects, their developers and their costs. • How many projects are included in your latest TYNDP that focus on the digitalisation and smartening of the grid? Which are their costs? • Which new priorities are to be added to the revised TYNDP as a result of the revision of the TEN-E Regulation? • What challenges do you foresee in the realization of the TYNDP? How do you think those could be overcome? • Are you developing/considering any R&D and pilot projects directly related to hydrogen? • What is the R&D annual expenditure of your entity on hydrogen and biomethane (m EUR/y)? • Are you developing/considering any power-to-gas projects? • Are you conducting any pilot projects regarding the injection of hydrogen in transmission networks to test the adequacy of equipment? • Are you developing/considering any R&D and pilot projects directly related to biomethane? • Please state the nationally adopted gas quality standards. • Do gas quality standards in your Member State (MS) allow for H2 volumes? • Please state issues that according to your opinion may arise due to differences in gas quality. • Is it legally/regulatory possible to inject or allow H2 volumes into the gas transmission network? • In your view as TSO, what would be the expected ratio of the future hydrogen network by 2030 in your country? • What is the treatment of hydrogen-ready and of non-hydrogen-ready infrastructure in the context of the assessment of the TYNDPs in terms assessment criteria, priorisation over other infrastructures? What does the Regulator accept in terms of additional costs? • Do you plan to install new pipelines dedicated specifically to the transportation of hydrogen/biomethane and if yes by when? • As a TSO, which technical, safety and economic challenges related to the hydrogen transportation do you consider crucial to overcome? • In your country of operation, are network operators allowed to own hydrogen production and/or storage facilities? • Is any form of CBA requested by the Network Operators for renewable hydrogen infrastructure?

	• Is there a national biomethane registry that collects information related to all movements/transactions from production to end-use of biomethane (excluding double-counting) and of certifying the special ("green", renewable) feature of the product.in your country? • Are you the Authorised Body for Guarantees of Origin (GOs) issuing for gas in the country? • Is the current regulation in your country in line with REDII EU regulation concerning the issuance of GOs for renewable gases (incl. hydrogen)? • Is there a more specific document including guidelines for the issuance, transfer and cancel of this type of GOs serving as guidance for the interested market players? • Are you importing/exporting GOs issued for renewable gases (incl. hydrogen)? • Have gas suppliers started cancelling GOs for gas disclosure on behalf of their consumers? • How do you plan to enhance the interoperability with the DSOs? • What is the grid connection cost payable by a hydrogen producer to you as a TSO? • What is the grid connection cost payable by a biomethane producer to you as a TSO?
DSOs	• How many of the operating biogas plants have upgrading to biomethane and are connected to the grid? Which is the total injection volume (bcm/y)? • How many of the operating biogas plants have upgrading to biomethane with no connection to the grid? Which is the total injection volume (bcm/y)? • Are the existing biogas production plants utilizing the overall country's potential considering to the availability of raw materials/feedstock (i.e. waste/ residues)? • Are you aware of key hydrogen generation projects promoted (IPCEIs, major projects promoted by market players, utilities, etc.)? Please name the project operators, starting year, nominal capacity, location • Are you aware of key biomethane generation projects promoted (major projects promoted by market players, utilities, etc.)? Please name the project operators, starting year, nominal capacity, location • How many hydrogen liquefaction facilities are there in the country? • How many liquid hydrogen gasification facilities are there in the country? • How many facilities for hydrogen conversion into a higher density chemical, such as ammonia, are there in the country? • How many facilities for recovering hydrogen from a higher density chemical, such as ammonia, are there in country? • How many anaerobic biodigesters are planned to become operational by 2030? Please name the project operators, starting year, nominal capacity, location. • Which is the total length (km) of the national pipeline distribution system? • Which are the hydrogen blends (%) that each of the components comprising the national gas distribution system can accommodate? • Are you coordinating with the TSO for issues related to the network operation/expansion necessary for the promotion of hydrogen and renewable gas? • Are you developing/considering any R&D and pilot projects directly related to hydrogen? If the answer yes, then please specify which. • Are you developing/considering any power-to-gas projects? If yes, then please specify which. • Are you conducting any pilot projects regarding the injection of hydrogen in distribution networks to test the adequacy of equipment?

	• Are you developing/considering any R&D and pilot projects directly related to biomethane? If the answer yes, then please specify which. • What is the R&D annual expenditure of your entity on biomethane and hydrogen (m EUR/y)? • How many projects are included in your latest NDP or any other relevant document/plan that promote renewable hydrogen via repurposing existing gas infrastructure? Which are their costs? • How many projects are included in your latest NDP or any other relevant document/plan that promote renewable hydrogen via developing new hydrogen-dedicated infrastructure? Which are their costs? • How many projects are included in your latest NDP or any other relevant document/plan that focus on the digitalisation and smartening of the grid? Which are their costs? • Please list which parts of the pipelines and components of the distribution systems can accept which blends of renewable hydrogen and biomethane? • Please describe which parts of the pipelines and components of the distribution systems are the most problematic in terms of hydrogen/biomethane acceptance? • Please, provide the information whether you plan to install new pipelines dedicated specifically to the transportation of hydrogen/biomethane. • As a DSO, which technical, safety and economic challenges related to the hydrogen or biomethane distribution do you consider crucial to overcome? • Please state which of the following appliances are currently hydrogen-ready, i.e. are optimally designed to run on hydrogen, but as of now configured to run on natural gas • How do you understand your new role for the efficient integration of Renewable Energy Sources? • How do you plan to enhance the interoperability with the TSO? • What is the grid connection cost payable by a hydrogen and a biomethane producer to you as a DSO?
CESEC delegates (i.e. Ministries of the CESEC countries)	• Which of the following existing national policy (plans, strategies, etc.) documents include actions or policies related renewable hydrogen? • Do you have a National Hydrogen Strategy? • Which are the renewable sources of energy in your country and their participation (%) in Gross Energy Consumption in 2021 (or earlier if not available)? • Did you have renewable hydrogen targets for 2021? • Did you have biomethane targets for 2021? • Has your county met the 2021 (or 2020) target share of energy from renewable sources? • Have you submitted your final NECP? • Is your NECP currently under revision? • Have you received recommendations by the Commission or the Energy Community on your NECP? • Do the recommendations made by the Commission or the Energy Community on your NECP concern renewable hydrogen targets? • Do the recommendations made by the Commission or the Energy Community on your NECP concern biomethane targets? • Which are the national production and consumption targets (bcm/y) for renewable and fossil-based hydrogen with abatement or in terms of % share in overall hydrogen production and consumption by 2030 and 2050? • Which sectors are prioritised for renewable hydrogen uptake?

	• Which challenges do you foresee in the realization of the development of renewable hydrogen as it is stipulated in the existing and/or under preparation policy and regulatory documents? • Is the country aspiring to become a net importer or producer of renewable hydrogen? Please state the relevant quantities (bcm/y) and the year. • Please indicate the national support schemes for renewable hydrogen production in your country. Add indicative budget if known. • State which EU Funds currently support renewable hydrogen projects in your country. • Which of the following existing national policy documents (plans, strategies, etc.) include biomethane? • Do you have a National Biomethane Plan • Which are the national production and consumption targets (bcm/y) for biomethane in 2030 and 2050? • Which challenges do you foresee in the realization of the development of biomethane as it is stipulated in the existing and/or under preparation policy and regulatory documents? • Please indicate the national support schemes for biomethane production in your country. • State which EU Funds currently support biomethane projects in your country. • What is the current overall production of biogas, biomethane and renewable hydrogen (bcm/y) in the country? • How is renewable (green and blue) hydrogen produced today in your country? • What is the current production (bcm/y) of other colors of hydrogen? • State today's renewable hydrogen consumption (bcm/y) per sector in your country? • State today's biomethane consumption (bcm/y) per sector in your country. • What is the current production of renewable electricity in the country (kWh)? • Is there renewable electricity surplus? If yes, how much (kWh/y)? • Please state the steps of the planning and permitting procedure, environmental, indicative time and responsible authorities (at national, regional and municipal levels) for renewable hydrogen production plants. Is some sort of generation and/or distribution license required? • Please include the applicable legislation and secondary regulations for the authorisation of renewable hydrogen production projects. • What actions have you taken or are planning to take in order to reduce red tape and speed up permitting when it comes to renewable hydrogen production? • Please state the steps of the planning and permitting procedure, indicative time, and responsible authorities (at national, regional and municipal levels) for biomethane production and injection into the grid. • Please include the applicable legislation and regulations for the authorisation of biogas/biomethane production projects • Which authorizations are required for repurposing of natural gas pipelines to hydrogen? • What actions have you taken or are planning to take in order to reduce red tape and speed up permitting when it comes to biomethane production? • Have you identified or plan to identify suitable land for renewable hydrogen production projects? If yes, how many km2 have you identified? • Which are the 'exclusion zones' in your country where renewable energy projects cannot be developed?

	• Give the quantities (bcm/y) of imported natural gas, renewable and fossil-based hydrogen with abatement (if any) and biomethane (if any), as well as the involved pipeline. • Is there a national biomethane registry that collects information related to all movements/transactions from production to end-use of biomethane (excluding double-counting) and of certifying the special ("green", renewable) feature of the product in your country? • Is there a national renewable hydrogen registry that collects information related to all movements/transactions from production to end-use of biomethane (excluding double-counting) and of certifying the special ("green", renewable) feature of the product in your country? • Which neighbouring countries do you treat as relevant to the development for large scale cross-border infrastructure taking into account national energy planning, TSO TYNDPs, etc. • What is the amount of R&D funds (Euros) you have channelled to green-hydrogen and biomethane related projects? • What are the expected benefits of the deployment of renewable hydrogen and low-carbon gases in your country in terms of GHG emissions reduction, job creation, GDP growth, security of supply, market coupling and smart system integration, etc. Please provide quantitative input and if possible, share any existing studies
NRAs	• Please state the steps of the planning and permitting procedure, environmental, indicative time, and responsible authorities (at national, regional and municipal levels) for renewable hydrogen production plants. Is some sort of generation and/or distribution license required? • Please include the applicable legislation and secondary regulations for the authorisation of hydrogen production projects • Please state the steps of the planning and permitting procedure, indicative time, and responsible authorities (at national, regional and municipal levels) for biomethane production and injection into the grid. • Please include the applicable legislation and regulations for the authorisation of biogas/biomethane production projects • Which authorizations are required for repurposing of natural gas pipelines to hydrogen? • How is hydrogen injection into the grid regulated in the country? • What challenges do you foresee with regards to the hydrogen injection into the grid? • What could be ways to overcome the challenges associated with the hydrogen injection into the grid according to your view? • What is your take on the recently published Delegated Act for Renewable Fuels of Non-Biological Origin (RFNBO) that sets the criteria for products that fall into the "renewable hydrogen" category? • What is the treatment of hydrogen-ready and of non-hydrogen-ready infrastructure in the context of the assessment of the NDPs in terms of assessment criteria, prioritisation over other infrastructures? What does the Regulator accept in terms of additional costs? • Which challenges do you foresee in the realization of the development of renewable hydrogen as it is stipulated in the existing and/or under preparation policy and regulatory documents? • Please indicate the national support schemes for renewable hydrogen production in your country. Add indicative budget if known. • Does biogas have a priority power grid access in the country concerned? Is there a legal basis?

	• Does biogas have a priority natural gas grid access in the country concerned? Is there a legal basis? • Does biogas have a priority district heating grid access in the country concerned? Is there a legal basis? • Is there a regulation governing the upgrade of biogas units to biomethane for the injection to the natural gas grid? • Does biomethane have a priority natural gas grid access in the country concerned? Is there a legal basis? • Does biomethane have a priority district heating grid access in the country concerned? Is there a legal basis? • Which challenges do you foresee in the realization of the development of biomethane as it is stipulated in the existing and/or under preparation policy and regulatory documents? • Please indicate the national support schemes for biomethane production in your country. • Is there a national biomethane registry that collects information related to all movements/transactions from production to end-use of biomethane (excluding double-counting) and of certifying the special ("green", renewable) feature of the product in your country? • Are you the Authorised Body for Guarantees of Origin (GOs) issuing for gas in the country? • Is the current regulation in your country in line with REDII EU regulation concerning the issuance of GOs for renewable gases (incl. hydrogen)? • Is there a more specific document including guidelines for the issuance, transfer and cancel of this type of GOs serving as guidance for the interested market players? • Are GOs for renewable gases (inc. hydrogen) being issued at the moment? • Are renewable gases (incl. hydrogen) GOs being imported/exported into/from your country's GOs registry? • Have gas suppliers/ renewable gases producers started cancelling GOs on behalf of consumers interested in certifying their green gas consumption? • Please provide the capacity (MW) of existing electrolysers in your country
H2 Europe	• Which are the unit costs associated with the production of renewable hydrogen? • Which are the unit costs associated with the production of fossil-based hydrogen with abatement? • From the perspective of the producers, which are the most prominent challenges regarding the production of renewable hydrogen? • From the perspective of the producers, which are the most prominent challenges regarding the production of fossil-based hydrogen with abatement? • From the perspective of the end users, which are the most prominent challenges regarding the consumption of renewable hydrogen by end-users? • From the perspective of the end users, which are the most prominent challenges regarding the consumption of fossil-based hydrogen with abatement by end-users? • What industrial equipment does the industry have to retrofit in order to be able to switch to pure hydrogen? • What types of industrial equipment can run already now with blends of hydrogen without any retrofit? Please indicate the acceptable blends. • From the perspective of renewable hydrogen producers, what are the main problems for permission procedures?

Annex C: List of Stakeholders contacted

Country	Ministries/CESEC Delegates	National Regulatory Authorities	Transmission System Operators	Distribution System Operators
Albania	Contacted/no input	Contacted/no input	Contacted/no input	Not Contacted
Austria	Contacted/no input	Contacted/ received input	Contacted/ received input	Not Contacted
Bosnia and Herzegovina	Contacted/no input	Contacted/ received input	Contacted/ received input	Not Contacted
Bulgaria	Contacted/no input	Contacted/no input	Contacted/ received input	Contacted/no input
Croatia	Contacted/no input	Contacted/ received input	Contacted/ received input	Not Contacted
Greece	Contacted/no input	Contacted/ received input	Contacted/ received input	Contacted/no input
Hungary	Contacted/no input	Contacted/ received input	Contacted/ received input	Not Contacted
Italy	Contacted/no input	Contacted/no input	Contacted/ received input	Contacted/no input
Kosovo	Contacted/ received input	Not Contacted	Not available	Not available
Moldova	Contacted/no input	Contacted/no input	Contacted/ received input	Contacted/no input
Montenegro	Contacted/no input	Contacted/no input	Not available	Not available
North Macedonia	Contacted/no input	Contacted/no input	Contacted/no input	Not Contacted
Romania	Contacted/no input	Contacted/no input	Contacted/no input	Contacted/no input
Serbia	Contacted/no input	Contacted/no input	Contacted/no input	Not Contacted
Slovenia	Contacted/ received input	Contacted/no input	Contacted/ received input	Not Contacted
Ukraine	Contacted/no input	Contacted/no input	Contacted/ received input	Not Contacted

Contacted/ received input	light purple
Contacted/no input	medium purple
Not Contacted	dark purple
Not available	white

Stakeholder	Group	Policy-related	Infrastructure-related	Planning, Permitting, Environment	Technical/ Research	Regulation
ACER	European Organisation					+
Albanian Energy Regulatory Authority (ERE), Energie-Control Austria (E-Control), Energy & Water Regulatory Commission (EWRC),Croatian energy regulatory agency (HERA), Regulatory Authority for Energy (PAE/RAE), Hungarian Energy and Public Utility Regulatory Authority (MEKH), Autorità di Regolazione per Energia Reti e Ambiente (ARERA), Energy and Water Services Regulatory Commission of the Republic of North Macedonia (ERC), National Agency for Energy Regulation of the Republic of Moldova (ANRE), (REGAGEN) Energy Regulatory Agency - Montenegro, Romanian Energy Regulatory Authority (ANRE), Energy Agency of the Republic of Serbia (AERS), Regulatory Commission for Energy in Federation of Bosnia and Herzegovina (FERK), Slovenian Regulatory Authority (AGEN RS), National Commission implementing state regulation in the fields of energy and utilities (NERC – Ukraine)	NRA					+
Albgaz, OST, Bulgartransgaz EAD, Plinacro, LNG Croatia LLC, DESFA, FGSZ Natural Gas, Gaztranzit, Snam Rete Gas S.p.A., Vestmoldtransgaz, Transgaz S.A., Depomures, PLINOVODI d.o.o., Gas Transmission System Operator of Ukraine LLC, Srbijagas, BH-gas, Trans Adriatic Pipeline (TAP), Gas Interconnector Greece-Bulgaria (IGB), Gas Connect Austria GmbH, Trans Austria Gasleitung, Moldovagaz	TSO (gas)		+			
Boss Construction, Cyrus Energy, Sombor-gas, Yugorosgaz, Beogaz, JP Gas Temerin, Subotigas, Oktobar, Interklima, MTS, Gasruma, Sremgas, Resava Gas, Ingas JP, Polet, Novisadgas, Elgas Senta, JKP Graditelj, Sigas, Uzicegas, Toplana Sabac, Adistribuzionegas S.R.L., AMG S.R.L., AMG Energia SPA, Amalfitana Gas S.R.L., Amg Reti Gas S.P.A., A.G.RE. SPA, A.E.S. Fano Distribuzione Gas SRL, Aemme Linea Distribuzione Gas SRL, Adrigas, Acqui Rete Gas SRL, Acquambiente Marche SRL, Acegasapsamga S.P.A., Alto Garda servizi SPA, Amarad Distributie, CONI, BERG Sistem Gaz, CPL Concordia Filiala, CLUJ Romania, Delgaz Grid, Distribugas Sud Retele, Distrigaz Vest, Cordun Gaz, Design Project, Dornacor Invest, Austrian Gas Grid Management AG, Bulgargaz, Balti Gaz, Chisinau Gas, JKP Slovenj Gradec, Plinarna MB, Javno podjetje plinovod Sevnica, Plinstal (ENOS),	DSO		+			

Stakeholder	Group	Policy-related	Infrastructure-related	Planning, Permitting, Environment	Technical/ Research	Regulation
Rotalingaz (Altarisenergy group)						
Croatia: Ministry of Foreign Affairs, Ministry of Economy and Sustainable Development Greece: Permanent Representation of Greece to the EU, Ministry of Environment and Energy Serbia: Ministry of Mining and Energy, Ministry of Foreign Affairs, Ministry of European Integration North Macedonia: Secretariat for European Affairs, Ministry of Foreign Affairs Montenegro: Ministry of Economy, Ministry of Foreign Affairs Bosnia and Herzegovina: Ministry of Foreign Trade and Economic Relations, Ministry of Foreign Affairs Austria: Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology Hungary: Ministry of Foreign Affairs Slovenia: Delegates of the Government Ukraine: Ministry of Foreign Affairs Bulgaria: Ministry of Energy, Permanent Representation of Bulgaria in the EU Italy: Ministry of Economic Development, Ministry of Foreign Affairs Romania: Permanent Representation of Romania in the EU Moldova: Ministry of Foreign Affairs Albania: Ministry of Infrastructure and Energy Kosovo: Delegates of the Government, Embassy in Belgium	CESEC Delegates/Ministries	+				
Hydrogen Europe		+				
IRENA		+				
GEODE			+			
Gastrade, Hellenic Republic Asset Development Plan (HREF), State Agency on Energy Efficiency and Energy Saving of Ukraine, Naftogas, Albpetrol	Other					

Annex D: Capacity factors

PV					
	2030	**2035**	**2040**	**2045**	**2050**
Albania	18.89%	18.89%	18.89%	18.89%	18.89%
Austria	14.90%	14.90%	14.90%	14.90%	14.90%
BiH	15.86%	15.86%	15.86%	15.86%	15.86%
Bulgaria	17.80%	17.80%	17.80%	17.80%	17.80%
Croatia	17.50%	17.50%	17.50%	17.50%	17.50%
Greece	20.90%	20.90%	20.90%	20.90%	20.90%
Hungary	16.70%	16.70%	16.70%	16.70%	16.70%
Italy	18.70%	18.70%	18.70%	18.70%	18.70%
Kosovo	12.86%	12.86%	12.86%	12.86%	12.86%
Montenegro	16.30%	16.30%	16.30%	16.30%	16.30%
Republic of Moldova	11.44%	11.44%	11.44%	11.44%	11.44%
North Macedonia	14.60%	14.60%	14.60%	14.60%	14.60%
Romania	16.90%	16.90%	16.90%	16.90%	16.90%
Serbia	11.43%	11.43%	11.43%	11.43%	11.43%
Slovenia	16.10%	16.10%	16.10%	16.10%	16.10%
Ukraine	11.98%	11.98%	11.98%	11.98%	11.98%
Onshore Wind					
	2030	**2035**	**2040**	**2045**	**2050**
Albania	26.90%	27.12%	27.34%	27.57%	27.80%
Austria	29.70%	29.94%	30.19%	30.44%	30.69%
BiH	21.44%	21.62%	21.79%	21.97%	22.15%
Bulgaria	26.90%	27.12%	27.34%	27.57%	27.80%
Croatia	30.50%	30.75%	31.00%	31.26%	31.52%
Greece	32.50%	32.77%	33.04%	33.31%	33.58%
Hungary	26.50%	26.72%	26.94%	27.16%	27.38%
Italy	28.00%	28.23%	28.46%	28.70%	28.93%
Kosovo	31.60%	31.86%	32.12%	32.38%	32.65%
Montenegro	31.56%	31.82%	32.09%	32.35%	32.62%
Republic of Moldova	26.40%	26.62%	26.84%	27.06%	27.28%
North Macedonia	37.30%	37.61%	37.92%	38.23%	38.55%
Romania	26.40%	26.62%	26.84%	27.06%	27.28%
Serbia	28.95%	29.19%	29.43%	29.67%	29.91%
Slovenia	26.50%	26.72%	26.94%	27.16%	27.38%
Ukraine	29.57%	29.81%	30.06%	30.31%	30.56%
Offshore Wind					
	2030	**2035**	**2040**	**2045**	**2050**

Albania	28.80%	29.18%	29.56%	29.95%	30.34%
Austria					
BiH	28.80%	29.18%	29.56%	29.95%	30.34%
Bulgaria	36.10%	36.57%	37.05%	37.54%	38.03%
Croatia	28.80%	29.18%	29.56%	29.95%	30.34%
Greece	42.30%	42.86%	43.42%	43.99%	44.57%
Hungary					
Italy	34.00%	34.45%	34.90%	35.36%	35.82%
Kosovo					
Montenegro	28.80%	29.18%	29.56%	29.95%	30.34%
Republic of Moldova					
North Macedonia					
Romania	38.70%	39.21%	39.72%	40.24%	40.77%
Serbia					
Slovenia	34.00%	34.45%	34.90%	35.36%	35.82%
Ukraine	38.70%	39.21%	39.72%	40.24%	40.77%

Annex E: Levelised cost of hydrogen and biomethane input data

This Annex includes main information used as input for the calculation of the levelised costs of hydrogen and biomethane production in Chapter 3.

Evolution of CAPEX, OPEX, stack replacement costs and efficiency of AEL electrolyser

Year of installation	CAPEX AEL electrolyser (EUR/kW)	OPEX AEL electrolyser (EUR/kW)	Stack replacement cost AEL electrolyser (EUR/kW)	Efficiency AEL electrolyser (%)
2030	494.06	19.76	203.44	68.0%
2035	459.48	18.38	189.20	69.8%
2040	424.89	17.00	174.96	71.5%
2045	390.31	15.61	160.72	73.2%
2050	355.73	14.23	146.48	75.0%

Evolution of CAPEX and OPEX for all three RES technologies

Year of installation	CAPEX 100 MW PV (EUR/kW)	CAPEX 20 MW Wind Onshore (EUR/kW)	CAPEX 240 MW Wind Offshore (EUR/kW)	OPEX 100 MW PV (EUR/kW)	OPEX 20 MW Wind Onshore (EUR/kW)	OPEX 240 MW Wind Offshore (EUR/kW)
2030	387	1,000	1,898	12.6	14	31
2040	371	950	1,843	9.5	12	29
2050	355	925	1,787	8.2	12	28

WACC and interest rates

Country	WACC	Interest rate (%)
Austria	7.60%	8%
Bulgaria	8.71%	4%
Croatia	9.03%	8%
Greece	9.58%	8%
Hungary	8.91%	6%
Italy	8.60%	4%
Romania	8.91%	4%
Slovenia	8.24%	4%

Albania	10.30%	8%
Bosnia and Herzegovina	11.62%	8%
Kosovo	11.62%	8%
Montenegro	10.45%	8%
Republic of Moldova	11.56%	6%
North Macedonia	9.89%	8%
Serbia	9.41%	6%
Ukraine	11.41%	8%

Assumptions for the biogas investment

Biogas investment	
Biogas production capacity (Nm3/h)	100, 500, 1000 (dependent on the country)
Operating hours	8,000
CAPEX uic (EUR/MWh)	25, 20, 15 (dependent on the plant size)
OPEX uic (EUR/MWh)	22, 17, 12 (dependent on the plant size)
Degradation rate (%)	1%

Assumptions for the biogas upgrading and gas grid injection

Biogas upgrading and grid injection investment	
CAPEX uic (EUR/MWh)	17, 13, 10 (dependent on the plant size)
OPEX uic (EUR/MWh)	26, 12, 9 (dependent on the plant size)
Efficiency	98%
Biomethane content in biogas	57%

Annex F: Renewable gases production and consumption levels/targets

Estimated hydrogen production[278] and consumption levels/targets (2030 & 2050)

	Hydrogen in 2030			Hydrogen in 2050		
	Supply (TWh/y)	Demand (TWh/y)	Source	Supply (TWh/y)	Demand (TWh/y)	Source
AL	n.a.	0.02	NECP	0.23[279] (Renewable H_2)	0.23[280] (Renewable H_2)	NECP
AT	4.3	4.7-11.6	PCI/PMI process needs[281]	n.a.	59.5-92.2[282]	Hydrogen Strategy
BA	n.a.	n.a.	-	n.a	n.a	-
BG	6.6	4.5[283]	PCI/PMI process needs	n.a.	13,2 TWh[284]	ICIS/market assessment
EL	5.32	4.40	Draft NECP	90.65 (Renewable H_2)	63.6 (Renewable H_2)	Draft NECP
HR	1.3	0.46	Draft NECP	6.8-8.8 (Renewable H_2)	8.4-11.5 (Renewable H_2)	Hydrogen Strategy
HU	0.86	1.7	Draft NECP	n.a.	4.00	Draft NECP
IT	n.a.	8.35	Draft NECP	n.a.	20% of energy penetration in final energy demand	Hydrogen Strategy
MD	n.a.	n.a.	-	n.a.	n.a.	-
ME	n.a.	n.a.	-	n.a	n.a.	-
MK	n.a.	n.a.	-	n.a.	n.a.	-
RO	13.2	13.2	PCI/PMI process needs	n.a.	2040: 37,0 TWh	Draft Updated NECP

278 Figures referring to supply are the projected figures according to NECPs, PCI/PMI data, NHSs, and not the results of the modelling analysis.
279 2040 forecast
280 2040 forecast
281 Based on complementary data/information by AT in the context of PCI/PMI process (29/3/2023)
282 2040 forecast, lower end used in the modeling exercise
283 Assuming all hydrogen demand is supplied through renewable hydrogen
284 Bulgaria launches demand assessment survey for hydrogen transmission capacity | ICIS

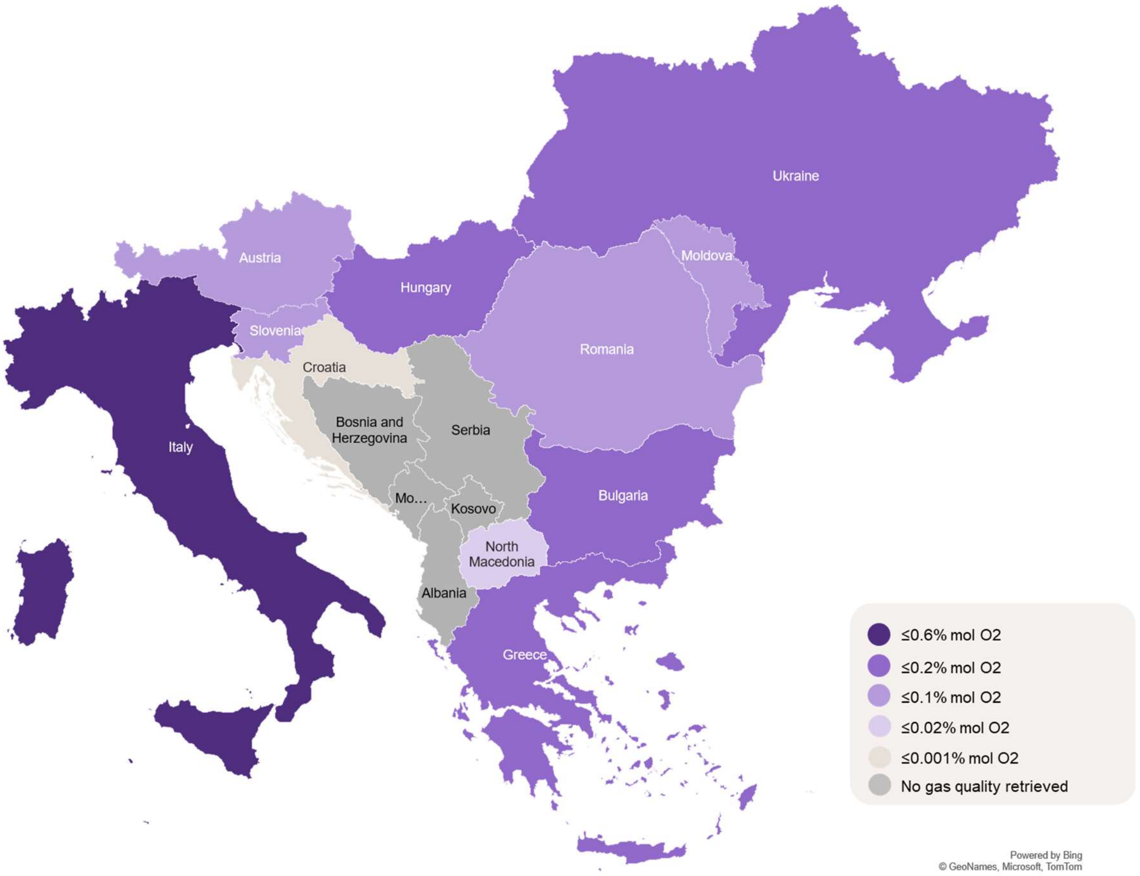
	Hydrogen in 2030			Hydrogen in 2050		
	Supply (TWh/y)	Demand (TWh/y)	Source	Supply (TWh/y)	Demand (TWh/y)	Source
					2050: 43,3 TWh[285]	
RS	n.a.	1.1	Draft NECP	n.a.	6.1	Draft NECP
SI	0.40	0.40	Draft NECP	1.95[286]	1.95	Draft NECP
UA	21	10,5	External study[287]	n.a.	50 TWh	Team assumptions
XK	n.a.	n.a.	-	n.a.	n.a.	-

Estimated biomethane production and consumption levels (2030 & 2050)

	Biomethane in 2030			Biomethane in 2050		
	Production (TWh/y)	Consumption (TWh/y)	Source	Production (TWh/y)	Consumption (TWh/y)	Source
AL	n.a.	n.a.	-	n.a.	n.a.	-
AT	n.a.	n.a.	-	n.a.	n.a.	-
BA	n.a.	n.a.	-	n.a.	n.a.	-
BG	n.a.	5.8-7.73	TYNDP2022		14.50-19.33	TYNDP2022
EL	1.988	n.a.	Draft NECP	n.a.	n.a.	-
HR	0.006	n.a.	Energy Development Strategy	0.225-1.408	n.a.	Energy Development Strategy
HU	n.a.	n.a.	-	n.a.	n.a.	-
IT	10.75 (biomethane from agricultural waste & MSW)	n.a.	NECP	n.a.	n.a.	-
MD	n.a.	n.a.	-	n.a.	n.a.	-
ME	n.a.	n.a.	-	n.a.	n.a.	-
MK	n.a.	n.a.	-	n.a.	n.a.	-
RO	n.a.	3.02-17.36	TYNDP2022		32.54-43.39	TYNDP2022
RS	n.a.	n.a.	-	n.a.	n.a.	-
SI	n.a.	n.a.	-	n.a.	n.a.	-
UA	n.a.	n.a.	-	n.a.	n.a.	-
XK	n.a.	n.a.	-	n.a.	n.a.	-

285 ROMANIA - DRAFT UPDATED NECP 2021-2030.pdf (europa.eu)
286 2040 forecasts
287 It is assumed by the team that out of the projected 21 TWh of green hydrogen production will be destined for the domestic market in 2030. Source: Green_Hydrogen_in_Ukraine.pdf (energypartnership-ukraine.org)

Annex G: Oxygen limits



Annex H: Hydrogen cross-border flows

Hydrogen Cross-border Flows Scenario A (in TWh)

Fiscal Year	AT-DE	AT-HU	AT-SL	BG-GR	BG-RO	BG-RS	HU-HR	HU-RO	IT-AT	SL-HR	SL-HU	SL-IT	TN-IT	UA-HU	UA-RO
2030	0.0	0.2	0.0	-18.5	18.0	0.0	0.0	-7.4	-2.5	0.0	0.0	0.0	0.0	-6.3	0.0
2031	0.0	-1.8	0.0	-21.0	19.8	0.0	0.0	-7.4	-7.6	0.0	0.0	0.0	0.0	-4.2	0.0
2032	0.0	1.1	0.0	-20.4	20.2	0.0	0.0	-5.9	-4.1	0.0	0.0	0.0	0.0	-5.4	0.0
2033	0.0	2.6	0.0	-20.0	20.0	0.0	0.0	-3.8	-2.6	0.0	0.0	0.0	0.0	-4.9	0.0
2034	0.0	2.9	0.0	-21.2	20.8	0.0	0.0	-2.7	-1.5	0.0	0.0	0.0	0.0	-4.0	0.0
2035	0.0	4.0	0.0	-21.9	21.3	0.0	0.0	-1.3	1.3	0.0	0.0	0.0	0.0	-3.7	0.0
2036	0.0	4.4	0.0	-19.5	19.3	0.0	0.0	0.2	3.9	0.0	0.0	0.0	0.0	-2.7	0.0
2037	0.0	4.0	0.0	-19.6	19.3	0.0	0.0	2.3	4.0	0.0	0.0	0.0	0.0	-2.3	0.0
2038	0.0	1.9	0.3	-17.9	19.7	0.0	0.0	3.6	3.4	0.3	0.0	0.0	0.0	-1.1	0.0
2039	0.0	1.3	1.4	-14.5	19.5	0.0	4.3	8.4	3.5	-5.2	2.5	4.9	0.0	7.9	-5.8
2040	0.0	-0.2	2.9	-8.8	18.3	0.0	3.7	10.3	2.7	-4.2	2.9	4.9	0.0	9.6	-5.3
2041	0.0	0.4	0.8	-7.6	19.5	0.0	3.8	8.1	-1.9	-4.6	1.7	4.6	0.0	8.5	-4.5
2042	0.0	-2.4	1.6	-7.0	18.4	0.0	1.9	8.7	-2.4	-2.1	-1.3	5.6	0.0	9.6	-3.0
2043	0.0	-1.7	1.9	-5.6	16.8	0.0	4.2	9.0	-3.5	-3.8	-0.4	6.2	0.0	11.3	-2.0
2044	0.0	-3.8	1.1	-4.9	17.6	0.0	4.6	7.4	-6.1	-4.4	-0.6	6.6	0.0	10.3	-0.9
2045	0.0	-5.5	-0.3	-4.1	14.3	0.0	7.0	5.3	-11.3	-7.0	0.9	6.3	0.0	9.8	2.9
2046	0.0	-9.2	-3.2	9.7	6.1	0.0	5.0	5.2	-27.0	-6.1	-0.8	4.6	0.0	11.0	8.5
2047	0.0	-10.8	-3.9	8.9	11.0	0.0	6.6	-1.8	-29.0	-5.8	-3.4	6.2	0.0	10.3	10.7
2048	0.0	-9.7	-4.5	13.9	7.9	0.0	5.7	1.8	-28.4	-7.2	-2.8	6.9	0.0	10.8	11.8
2049	0.0	-10.0	-5.6	17.3	6.3	0.0	7.0	0.2	-30.3	-8.0	-3.4	7.1	0.0	11.3	15.3
2050	0.0	-8.1	-6.1	18.1	3.4	-2.8	7.3	0.8	-30.3	-8.9	-2.9	6.5	0.0	10.0	13.8

Hydrogen Cross-border Flows Scenario B (in TWh)

Fiscal Year	AT-DE	AT-HU	AT-SL	BG-GR	BG-RO	BG-RS	CZ-DE	HU-HR	HU-RO	HU-SK	IT-AT	SK-AT	SK-CZ	UA-SK	SL-HR	SL-HU	SL-IT	TN-IT	UA-HU	UA-RO
2030	25.5	0.0	0.0	-2.7	0.0	0.0	0.0	0.0	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	15.4	0.0	0.0
2031	26.1	0.0	0.0	-3.2	0.0	0.0	0.0	0.0	0.0	0.0	20.4	0.0	0.0	0.0	0.0	0.0	0.0	21.2	0.0	0.0
2032	26.9	0.0	0.0	-2.0	0.0	0.0	0.0	0.0	0.0	0.0	25.8	0.0	0.0	0.0	0.0	0.0	0.0	26.2	0.0	0.0
2033	27.3	0.0	0.0	-2.1	0.0	0.0	0.0	0.0	0.0	0.0	29.6	0.0	0.0	0.0	0.0	0.0	0.0	32.3	0.0	0.0
2034	27.9	0.0	-1.7	-6.1	5.2	0.0	0.0	2.1	-1.0	0.0	29.7	0.0	0.0	0.0	-1.7	0.0	0.0	35.4	0.0	0.0
2035	28.5	0.0	-2.5	-7.7	7.4	0.0	0.0	2.9	-1.9	0.0	29.3	0.0	0.0	0.0	-2.5	0.0	0.0	40.5	0.0	0.0
2036	25.3	0.0	-3.1	-8.8	8.3	0.0	4.0	4.6	-0.9	-3.0	29.4	0.6	4.0	7.6	-3.1	0.0	0.0	45.4	0.0	0.0
2037	19.6	0.0	-1.8	-8.5	14.1	0.0	10.2	2.2	-3.8	2.4	27.4	0.7	10.2	8.5	-0.5	0.0	0.0	49.9	0.0	0.0
2038	15.6	0.0	-4.8	-7.2	13.5	0.0	14.7	-3.6	0.3	4.0	22.5	1.1	14.7	11.7	6.0	0.0	0.0	50.2	0.0	0.0
2039	17.6	0.0	-8.3	-10.0	16.3	0.0	13.4	-1.0	-0.1	1.9	21.3	3.6	13.4	15.1	3.9	0.0	0.0	48.8	0.0	0.0
2040	29.6	0.0	-6.0	-2.4	15.3	0.0	2.3	1.7	4.2	-5.5	16.4	1.9	2.3	9.7	1.6	0.0	0.0	44.5	0.0	0.0
2041	24.0	0.0	0.9	-3.2	16.3	0.0	8.1	-4.9	3.2	2.3	14.6	3.5	8.1	9.4	8.3	0.0	0.0	39.4	0.0	0.0
2042	20.7	0.0	6.0	-5.5	18.3	0.0	12.1	-5.3	-1.0	6.7	18.6	3.9	12.1	9.3	8.4	0.0	6.9	39.7	0.0	0.0
2043	22.1	0.0	1.7	-4.1	16.6	0.0	11.3	-5.4	-0.8	6.6	14.4	5.0	11.3	9.7	9.2	0.0	6.8	38.6	0.0	0.0
2044	11.6	0.0	2.3	-8.3	21.1	0.0	22.7	-4.7	-5.4	17.4	2.1	5.6	22.7	10.8	9.3	0.0	7.0	34.0	0.0	0.0
2045	5.6	0.0	-0.4	-8.0	18.1	0.0	29.0	-9.3	1.2	20.8	-6.8	9.3	29.0	17.4	7.9	0.0	6.9	27.7	0.0	0.0
2046	1.6	-4.1	-4.9	2.2	13.3	0.0	33.6	-8.4	8.7	6.6	-13.0	10.9	33.6	38.0	7.3	0.0	6.9	57.9	0.0	0.0
2047	1.7	-4.5	-4.6	4.0	11.8	0.0	34.1	-7.2	11.2	6.4	-18.7	11.0	34.1	38.7	5.0	4.3	7.0	59.2	0.0	0.0
2048	2.8	-6.3	-6.6	5.9	12.8	0.0	34.0	-5.1	10.7	5.5	-22.6	11.0	34.0	39.5	4.3	6.0	6.9	59.9	0.0	0.0
2049	2.4	-4.4	-8.3	11.2	12.8	0.0	34.7	-3.0	9.9	5.9	-25.0	11.7	34.7	40.4	3.4	6.3	6.7	61.2	0.0	0.0
2050	1.3	-8.8	-7.4	13.5	9.4	0.0	31.0	-5.7	11.4	1.6	-31.2	10.8	31.0	40.2	5.0	5.2	6.5	44.8	0.0	0.0

Annex I: Revised TEN-E criteria for project evaluation under the PCI/PMI process

Criteria	Description
Priority Corridor for Hydrogen	The project must be necessary for at least one priority corridor for hydrogen as described in Article 4(1)(a) of the TEN-E Regulation.
Cost-Benefit Analysis	• The potential overall benefits of the candidate project must outweigh its costs, even in the longer term. This is in line with the provisions set in Article 4(1)(b) of the TEN-E Regulation. • To verify compliance with this criterion, the application must include the calculation of the Net Present Value (NPV) of the candidate project for the entire technical lifetime of the project.
Cross-Border Impact	As per Article 4(1)(c) of the TEN-E Regulation, the candidate project should either: • Involve at least two Member States, either directly or indirectly, by crossing the border of two or more Member States or via interconnection with a third country. • Be located within one Member State (either inland, offshore, or on islands) but have a significant cross-border impact. This is further detailed in point (1)(d) of Annex IV to the TEN-E Regulation, which specifies criteria for hydrogen transmission and cross-border hydrogen transport capacity. Additionally, point (1)(e) of Annex IV to the TEN-E Regulation mentions criteria for hydrogen storage or hydrogen reception facilities.
Sustainability	• The project should contribute to sustainability by reducing greenhouse gas emissions. • It should enhance the deployment of renewable or low-carbon hydrogen, especially hydrogen from renewable sources, particularly in hard-to-abate end-use applications in the industry and transport sectors where more energy-efficient solutions are not feasible. • The project should support variable renewable power generation by offering flexibility, storage solutions, or both.
Specific Criteria	The project should significantly contribute to at least one of the following specific criteria: • Market Integration: By connecting existing or emerging hydrogen networks of Member States or otherwise contributing to the emergence of a Union-wide network for the transport and storage of hydrogen. It should also ensure the interoperability of connected systems. • Security of Supply and Flexibility: Through appropriate connections and facilitating secure and reliable system operation. • Competition: By allowing access to multiple supply sources and network users on a transparent and non-discriminatory basis.

Key literature and data sources

	Title	Description
1	National energy and climate plan (NECP)	EU's energy and climate targets, policies, energy efficiency, GHG emission reductions
2	Ten-Year Network Development Plan (TYNDP)	Hydrogen Development projects, investment costs
3	National Hydrogen Strategy and other policy documents, where relevant.	Guidelines, targets, strategic plans, hydrogen transportation, technology R&D and innovation, Hydrogen production and supply, transport technologies
4	A hydrogen strategy for a climate-neutral Europe. Brussels, Belgium, European Commission 2020.	Guidelines, targets, strategic plans, investment projects, role of infrastructure, promoting research and innovation, international cooperation
5	The European Green Deal. Brussels, Belgium: Communication, European Commission 2019	EU Policies, strategic plans, transition to sustainable future
6	REPowerEU Plan, European Commission 2022	Policies, strategic plans, costs toward the clean energy transition
7	Revision of the TEN-E Regulation, European Parliament 2021	Guidelines for cross-border energy infrastructure, targets, strategic plans, legislative process, existing situation
8	Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community, Energy Community 2021	Hydrogen drivers, delivery infrastructure, potential to use hydrogen in various sectors, hydrogen policy frameworks and instruments
9	Opportunities for Hydrogen Energy Technologies Considering the National Energy& Climate Plans, FCH JU 2020	Production potential, current and potential hydrogen demand, current and planned infrastructure, hydrogen related targets, initiatives and policies, assessment of hydrogen deployment
10	Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, IRENA 2022	Technologies for transportation and storage, cost comparison
11	Decarbonising end-use sectors: Practical insights on green hydrogen. International Renewable Energy Agency (IRENA) 2021	Potential Market Opportunities, Market Projections, Hydrogen Strategies, best practices.
12	A European hydrogen infrastructure vision covering 28 countries, European Hydrogen Backbone 2022	Current status and projected Infrastructure development, potential for further development

	Title	Description
13	Renewable energy prospects for Central and South-Eastern Europe Energy Connectivity (CESEC), International Renewable Energy Agency (IRENA) 2020	Renewable potential in CESEC region, investment needs and economic benefits, energy security, policies
14	Outlook for biogas and Prospects for organic growth World Energy Outlook Special Report biomethane, IEA 2020	Biogas and biomethane supply potential and costs, implications for policy makers and industry, energy security
15	Biomethane: potential and cost in 2050, Engie 2021	Biomethane potential, production costs, LCOE
16	Hydrogen Production Costs 2021, Department for Business, Energy & Industrial Strategy 2021	Hydrogen production costs of different technologies, LCOE
17	Assessment of Hydrogen Delivery Options, European Commission 2021	Production and delivery costs, policy considerations
18	Energy efficiency and GHG emissions: Prospective scenarios for the chemical and petrochemical industry, Joint Research Centre (European Commission), 2017	Current technological status of the chemical and petrochemical industry, assessment of potential for energy efficiency and GHG emissions reduction
19	Global Hydrogen Review 2021, IEA 2021	Policy trends for hydrogen deployment, Hydrogen historical and projected demand by sector, hydrogen historical and projected production, current and projected investments, policy recommendations.
20	The Technical and Economic Potential of the H2@Scale Concept within the United States, NREL 2020	Potential Demand and Consumption, Technical and Economic Potential
21	Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables, G.Kakoulaki, I. Kougias, N.Taylor, F.Dolci, J.Moya, A.Jäger-Waldau, 2021	Hydrogen production at national and regional level in EU, green electricity potential
22	Hydrogen Europe. Green Hydrogen Investment and Support Report; 2020.	Hydrogen infrastructure and storage potential, hydrogen production investments, hydrogen applications
23	EU biomethane potential as analysed by Navigant for Gas for Climate, Gas for Climate group 2020	Biomethane actual production and future projections, GHG benefits.
24	Technical and economic conditions for injecting hydrogen into natural gas networks, Elengy 2019	Technical-economic conditions for injecting hydrogen into the networks, key R&D issues
25	How to transport and store hydrogen – facts and figures, ENTSOG, GIE and Hydrogen Europe	Hydrogen blending issues, technical considerations, and costs of repurposing an existing natural gas infrastructure, cost of transporting via pipelines, marine and port infrastructure and terminals repurposing needs.
26	Report Biogas, Bioenergy Europe, 2022	Biogas and Biomethane consumption, production, share in total energy

	Title	Description
27	Enabling Measures Roadmap for Green Hydrogen, IRENA, World Economic Forum, 2022	Barriers and priorities for hydrogen market development
28	Biomethane production potentials in the EU	Biomethane potential per technology and country, anaerobic digestion potential
29	"The national shaping of Europe's emerging hydrogen strategies: Cooperative or competitive hydrogen Politics?" J.T. M. Machado, B. Flynn, I. Williamson, CRNI, Vol. 23(1) 77–96, 2022	Hydrogen strategies, competition, policymaking, sustainable development, multi-level perspective, energy transition
30	Green hydrogen: A guide to policy making, IRENA 2020	National hydrogen strategies, governance system and enabling policies, barriers and policies, policy support
31	"Green Hydrogen in Europe: Do Strategies Meet Expectations?" A.Wolf, N. Zander	EU hydrogen strategy, hydrogen usage potential, national hydrogen policies, Capacity targets and consumption potentials
32	D6.1 Mapping the state of play of renewable gases in Europe, REGATRACE, 2020	Production and consumption of renewable gases, support schemes for biomethane, EU countries review
33	European Biomethane Map, EBA-GiE, 2020	Biomethane installations, evolution of biomethane production
34	SEA of Montenegro's National Climate Change Strategy (NCCS), 2015	Environmental assessment of Montenegro's National Climate Change Strategy
35	Montenegro Progress Reports under Renewable Energy Directive 2009/28/EC as adapted by the Ministerial Council Decision 2012/04/MC-EnC period 2018-2019	Report regarding the progress of Montenegro in renewable sources integration
36	SHARES summary results 2020	Renewable sources share
37	Renewable Energy Prospects for Central and South-Eastern Europe Energy Connectivity	Anticipated RES values in 2030 in terms of capacity and energy generation
38	Study on the Central and Southeastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables	Analysis of the potential for cost-effective renewable energy projects and associated infrastructure requirements in the CESEC region, in 2030 and 2050

Glossary

Reforming	A chemical process used to convert crude oil (typically having low octane ratings) into high-octane liquid products. The process converts low-octane linear hydrocarbons, branched alkanes and cyclic naphthenes, which are then partially dehydrogenated to produce high-octane aromatic hydrocarbons.
Renewable hydrogen	Hydrogen produced through the electrolysis of water powered by electricity from renewable sources or through the reforming of biogas or biochemical conversion of biomass
Fossil-based hydrogen with abatement	Hydrogen produced mainly from natural gas coupled with carbon capture and storage (CCS)

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