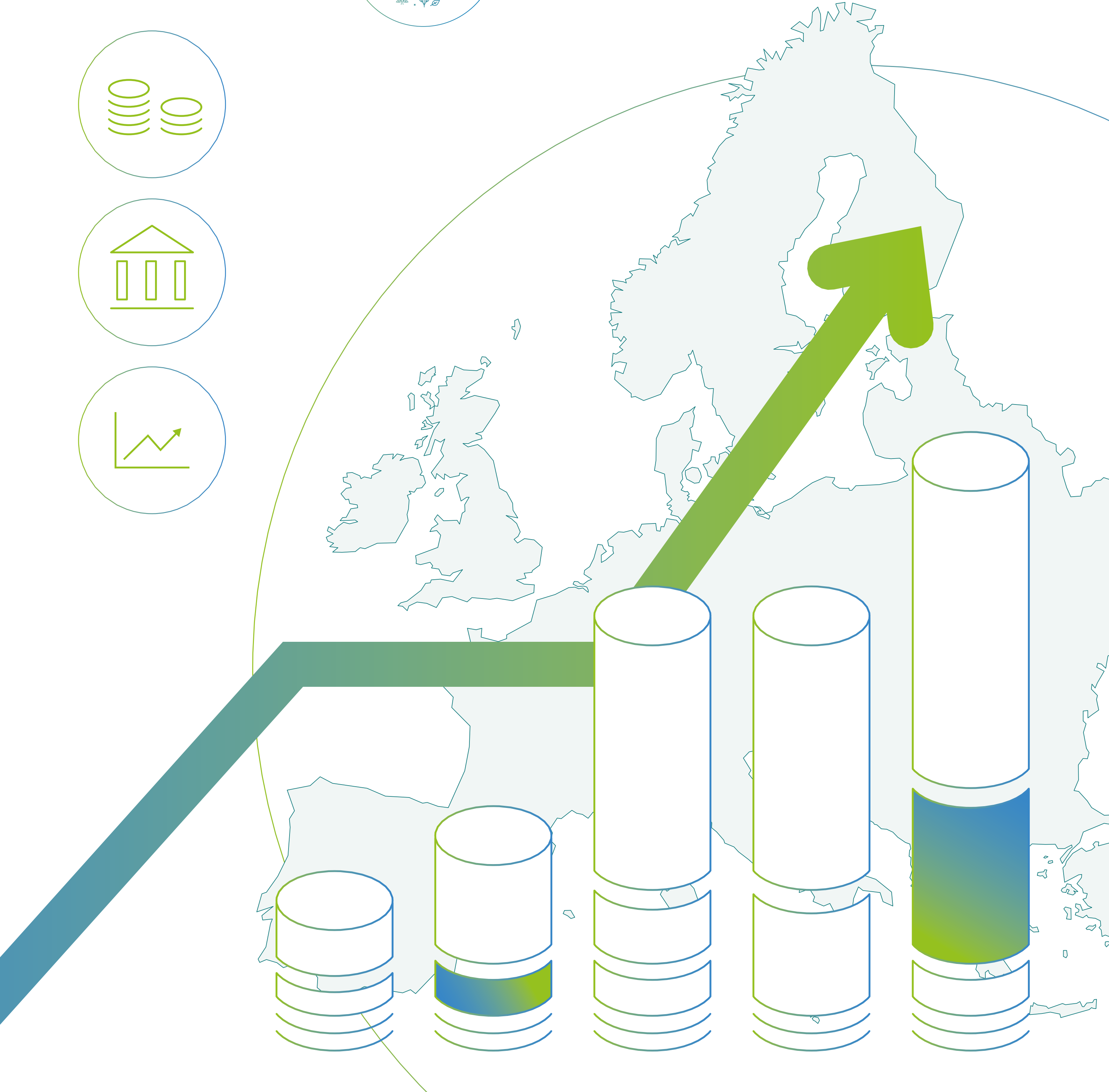
# LEARNBOOK: FINANCING OF HYDROGEN INFRASTRUCTURE

Clean Hydrogen Alliance
Transmission and Distribution Roundtable

European Clean Hydrogen Alliance



September 2024

**Disclaimer:**



# 1 INTRODUCTION

The European Clean Hydrogen Alliance (ECH2A – the Alliance) was founded in July 2020 to support and facilitate the implementation of the EU's Hydrogen Strategy. Its main aim is to create a European economy for clean (renewable and low carbon) hydrogen that covers the entire value chain from production to transportation to end-use in different sectors until 2030. More than 1,500 members form part of the ECH2A and represent many different stakeholders including private and public companies, research institutions, authorities, financial institutions, NGOs, associations, among others.

The Alliance is determined to promote investments in clean hydrogen across the value chain and to play a pivotal role in achieving the transformation of the European economy to a more sustainable, carbon-free economy. One key element to achieve this is a pipeline of investments that is regularly updated and that supports investors to implement their projects.

The Alliance's work is supported by the European Commission's services (DG GROW) in that they provide the Alliance's Secretariat, are a member of the Alliance's Steering Committee, organise and finance both virtual and hybrid Alliance workshops/events and provide a monthly newsletter. The Alliance is organised into six roundtables representing all different parts of the value chain, namely production, transmission and distribution, energy, buildings, industrial applications, and mobility. Two additional working groups on electrolyser partnerships and standardisation currently complete the setup.

The overall concept of the EU hydrogen corridors itself is outlined in much greater detail in the "Learnbook on Hydrogen Supply Corridors" (April 2023). For more detailed information on the specific corridors, this roundtable is currently working on a follow-up edition that outlines in greater detail timelines, status, construction costs, and involved parties of the respective routes. It will be published during the second half of 2024. Furthermore, interested readers should also refer to the "Learnbook on Hydrogen Imports into the EU market" (December 2023) to understand how large-scale imports of clean hydrogen into the EU will materialise. This Learnbook should therefore be read in conjunction with the other work of this roundtable.

## PURPOSE OF THE LEARNBOOK

The purpose of this Learnbook is to illustrate from an investor's perspective how hydrogen infrastructure financings could be carried out and which financing sources exist or could be established for this purpose. It is meant to contribute to the ongoing discussion on how to best support the financing of hydrogen infrastructure necessary to achieve the EU's climate goals. The Learnbook predominantly targets project promoters and policymakers but is also directed at other stakeholders notably financiers, researchers, and more generally those of the general public interested in this issue.

The Learnbook starts with an Executive Summary in the second chapter. Chapter 3 briefly presents the EU Hydrogen Supply Corridors identified in the European Commission's RePower EU Plan for readers not yet familiar with the topic. It then explains the key characteristics of natural gas infrastructure financings and why they are bankable in the fourth chapter. Chapter 5 explains why hydrogen infrastructure financings have to meet different criteria, what problems this causes, illustrates potential tariffication regimes and explains what mechanisms exist or could be implemented to overcome the current difficulties. The Learnbook concludes with recommendations for policymakers in the sixth chapter.

# 2 EXECUTIVE SUMMARY

Clean hydrogen is a key vector in the transition to a decarbonised energy system and economy and has been identified as one of the best options to de-fossilize carbon intensive processes and hard-to-abate industries, thereby supporting the EU's target to be climate neutral by 2050 and to address the energy storage challenge in an integrated future RES based energy system. A clean hydrogen transportation and distribution network will connect supply and demand in the EU and enable the adoption of clean hydrogen in all Member States, particularly those that neither produce sufficient clean hydrogen themselves nor have access to own import capacities. Implementing this network is a key requirement for the European clean hydrogen economy to develop and a prerequisite for achieving the EU's climate goals and to address intermittency of power supply.

Financing a network across Europe is one of the main challenges. Significant CAPEX is expected, with Germany alone budgeting almost EUR 20 billiion for its core network until 2032[1]. It would be logical to assume that natural gas infrastructure financings could act as a blueprint to develop European clean hydrogen infrastructure financings. But, as the European market for clean hydrogen is yet to evolve, several key success factors do not yet exist: the regulation for clean hydrogen infrastructure is thus far not finalised, until now the market does not show sufficient supply and demand, and value chains for clean hydrogen have still to emerge. The early stage of the clean hydrogen market means that mechanisms need to be installed which allow a risk-sharing between the stakeholders, so that no party bears risk beyond its appetite.

The European Commission and many Member States have implemented subsidy and grant programs that shall facilitate investment decisions by providing public money and therewith de-risking projects. The Learnbook shows these are powerful tools that help project developers attract a significant part of the funding needed. Notwithstanding this, it is becoming more and more clear that further risk mitigants are needed to ensure the attractiveness of clean hydrogen infrastructure projects for investors and lending financial institutions. Several instruments to achieve this are discussed in this Learnbook, most notably an amortisation account, clawback mechanisms, first-loss-tranches, and credit insurance. Particularly a combination thereof at EU level will help to de-risk an investment in hydrogen transportation infrastructure and make financings bankable and attractive for equity and debt investors alike.

Furthermore, the Learnbook provides various recommendations to policymakers. These cover an array of topics, including commercially incentivizing investors to incur risks in a nascent market, a larger support of development costs with public money, and widening the eligibility of public support from pipeline networks to clean hydrogen import and tank terminals. Also, the Learnbook identifies the need to clarify the circumstances under which European clean hydrogen infrastructure assets are considered sustainable.

1 Hydrogen Core Network – FNB Gas (fnb-gas.de)



# 3 THE EUROPEAN HYDROGEN INFRASTRUCTURE NETWORK

Clean hydrogen is viewed as one of the main vectors of the decarbonisation transition in Europe. Due to the limited potential for sufficient clean hydrogen production within the EU, it will be necessary to import hydrogen in large quantities into Europe[2]. In May 2022, the EU Commission outlined potential hydrogen supply corridors[3] as part of the wider RePowerEU Plan. Six main corridors have been selected as a means to secure a stable and large-scale flow of hydrogen into and within the European Union:

- South Central (Adriatic) $H_2$ corridor
- South-Western (Iberian) $H_2$ corridor
- North Sea $H_2$ corridor
- Nordic Baltic $H_2$ corridor
- Eastern $H_2$ corridor
- South-eastern $H_2$ corridor

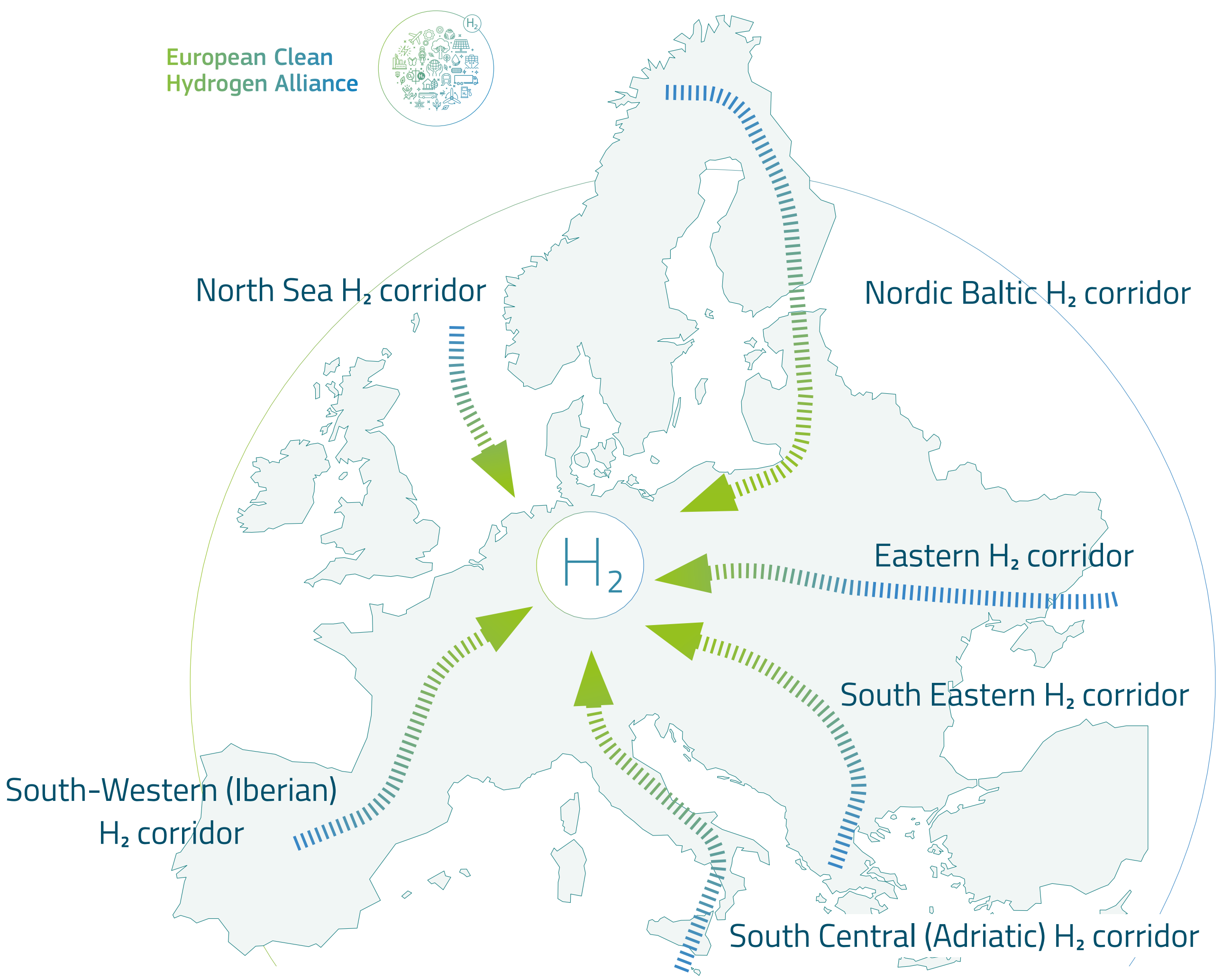



Figure 1: The European Hydrogen Supply Corridors

2 The RePowerEU plan foresees a renewable $H_2$ production of 10 Mt/y within the EU and imports of 10 Mt/y into the EU, all by 2030. See chapter 3.1. of the Learnbook on Hydrogen Imports to the EU Market for more information.

3 These corridors are described in the Learnbook on Hydrogen Supply Corridors.

The corridors connect those regions with the potential to become major hydrogen production hubs such as South Europe and North Africa (Adriatic and Iberian Corridors), the North Sea (North Sea Corridor), Ukraine (Eastern Corridor), Scandinavia (Nordic Baltic Corridor) and Eastern Mediterranean / GCC (South Eastern Corridor) to be able to feed all major demand hubs for clean hydrogen across the EU. In that regard, it should be noted that all corridors either go to Germany or have a direct connection to the planned German hydrogen grid, given the country's location and the size of its energy-intensive industry.

Each corridor consists of several pipelines including branches stretching from the main pipelines that form a cluster and ultimately a grid. As a share of the hydrogen needs to be imported, import terminals are another essential part of each corridor. Additional facilities such as storage, crackers, etc. will eventually emerge along the corridors, but they are out of the scope of a corridor and not subject of this Learnbook.

The planned pipeline network will require significant investments over the next decades. Whilst some of the hydrogen corridors will primarily repurpose existing natural gas pipelines to establish long-distance clean hydrogen transport infrastructure (e. g. the South Central Corridor), other corridors (e. g. the Nordic-Baltic Corridor) will see a much higher percentage of completely new pipelines. The most likely scenario is that the overall clean hydrogen network in the European Union will be a mix of new pipelines and a conversion of existing ones.

Together with the six main corridors, clean $H_2$ pipelines will need to be developed to further connect demand centres that are not directly on the corridors, which also will require financing. These grids will be more local and smaller in size and will be primarily developed by DSOs (distribution system operators), according to the Hydrogen and Decarbonised Gas package[4].


4 Hydrogen and Decarbonised Gas Package comprises Directive (EU) 2024/1788 and Regulation (EU) 2024/1789.



# 4 CHARACTERISTICS OF AND LESSONS LEARNT FROM NATURAL GAS INFRASTRUCTURE FINANCINGS

The following chapter provides an understanding on how financings of natural gas infrastructure are currently designed and which lessons have been learnt that might be useful for the financing of the EU's clean hydrogen infrastructure. Many market participants assume hydrogen infrastructure financings to work in the same fashion, so it is important to understand what the main characteristics are and how they contribute to sponsors taking final investment decisions and banks lending money. This chapter sets the basis for the financing options for hydrogen infrastructure that are presented in chapter 5.

## 4.1 REGULATION

Typically for these kinds of infrastructure, a natural gas network (both on a transmission and a distribution level) constitutes a so-called natural monopoly. From a purely economic perspective, it does not make sense to have more than one network due to the high investment costs associated with its construction and maintenance. But unregulated monopolies cause welfare losses due to typically lower quality, higher prices, and a slower pace of invention. This means that whilst it makes economic sense to have only one network being built and, hence, allow a European network to exist, it is beneficial to the economy to regulate the national or regional monopolies that make up this European network. This is the reason why gas networks are financially regulated within the European Union whilst LNG import terminals are not necessarily regulated: the former is by default a natural monopoly, the latter are exposed to competition in the market.

It should be noted that some Transmission System Operators (TSOs) are exempt from the standard regulatory framework, for example because they operate import pipelines with fixed offtakers that came into operation before 2019.

### TARIFFICATION REGIMES

The natural gas market regulation is designed and enforced by the respective national regulators for every EU member state individually but follows broadly the same principles across the EU. The framework for the regulation of pipeline networks is stipulated in the **EU Tariff Network Code** (TAR NC) and allows for two options: price cap or non-price cap, where a non-price cap corresponds to all other regulatory regimes than a price cap, such as revenue cap, rate of return, and cost plus[5]. The revenue cap regime is the most frequent one among non-price cap regimes.

The price cap sets a maximum tariff typically on national level an operator may charge within a so-called entry-exit system (EES)[6]. The tariff is based on a target revenue and implicates that there is no limit in terms of earnings but also no guarantee a certain revenue level is reached. Currently this scheme is either fully or at least partly applied for example in Austria and Italy. Accordingly, the TSO bears the so-called 'volume risk', which, depending on the concrete set-up, corresponds to the possibility of higher revenues in case of higher volumes / bookings than forecasted and vice versa.

5 Definitions for price cap and non-price cap are in Article 3(17) and Article 3(3) of the TAR NC respectively.

6 The regulator makes a motivated decision on tariffs (via the so-called reference price methodology) – and, if applicable, on price caps – and tariffs are set at the level of an EES (Art. 6(3) TAR NC), which generally corresponds to a member state, subject to exceptions. A formal definition of an EES is introduced in Art. 2(57) DIR of the Hydrogen and Decarbonised Gas Market Package.

Contrary to this, the concept of a revenue cap limits the overall revenues a Transmission System Operator (TSO) or a Distribution System Operator (DSO) may make. From a pre-defined maximum earnings level, a tariff is derived that is fixed for the so called 'tariff period'. In case of under-recovery in any given year, the regulation allows to incur more revenues either in the next years of the same regulatory period or in the following regulatory period, depending on the individual member state. This basically guarantees the TSO a certain revenue level at least over the mid-term, with no volume risk for the TSO. This scheme is for example applied in Germany, Belgium, Spain, Poland and The Netherlands and is generally the more prevalent one in the EU.

A simplified formula of the revenue cap in natural gas network regulation[7] looks like this:

**MRA = CCO × CF × INF + RA**

with **MRA** – Maximum Revenue Allowance
**CCO** – Costs to Construct and Operate
**CF** – Cost Factor
**INF** – Inflation Factor
**RA** – Regulatory Account

This formula is applied during an entire regulatory period, with each period lasting between two and six years, depending on the member state. Therefore, the individual components and the overall MRA do not vary from year to year but stay steady during a pre-defined time frame.

### COSTS TO CONSTRUCT AND OPERATE

The costs comprise all the expenses that are necessary to construct and operate the natural gas network. One of the key determinants is the depreciation of the regulated asset base (RAB). The RAB is the sum of all investments a service provider has made in its network, and it includes costs for development, construction, commissioning, and maintenance capital expenditures (CAPEX), as well as asset depreciation. A natural gas network operator makes yearly depreciations on the RAB in accordance with the respective depreciation period set by the national regulator for the asset in question[8]. If the operator invests into new infrastructure, the RAB increases by the value of this new asset and will then gradually reduce over the life of the asset.

It is important to understand that a service provider cannot invest freely. In all EU countries, there is a mandatory and revolving network planning in which the TSOs outline their respective investment plans. The national regulatory authority (NRA) in turn will only consider the associated CAPEX eligible if they deem the investment is necessary for the operation of the network[9].

The other main contributor to the CCO is the operating costs. Those costs are derived from actual costs the respective TSO has incurred, typically being spread over a period of several years to avoid companies moving costs into one specific year that serves as a basis for cost determination (and then benefitting from a higher cost basis throughout the entire regulatory period). The costs to operate a natural gas network mainly include operation of compressors, pipeline cleaning and inspection, labour costs, administration, etc.

Costs of capital also need to be accounted for. This includes cost of debt, predominantly interest expenses and fees, and costs of equity, i. e., the allowed return on equity (RoE) the NRA has accepted. The maximum RoE allowed is set by the national regulator and varies from one regulatory period to another and between the various member states. It should be as low as possible to avoid unnecessary costs for end-users, but it needs to be high enough to incentivise investments into the network and attract sufficient external funds. Typically, the return of the respective Member States ' state bonds is taken as a proxy and a certain premium is added.

### COST FACTOR

It is the goal of the national regulator to require the system operator to act in the most cost-efficient manner. Therefore, it has become common for regulators in Member States to introduce an efficiency factor by which the management of a natural gas network operator will be required to decrease those costs that are directly under a TSO's or DSO's control in order to reach the MRA.

Typically, there is a distinction between those costs that are directly within the control of the network operator and those that are not. The latter are directly factored into the tariff, the former are subject to a benchmarking with other TSOs. If an operator is at least as good as its peers, the factor remains at 100 % and if not, it is decreased below 100 %.

7 It should be noted that the formula is simplified and the intention is merely to illustrate the most common regulatory approach in the EU. Every member state has a different way how to transform EU law into national law and the Learnbook does not intend to precisely discuss the specialties of the regulation in every member state.

8 For example, if the regulatory lifetime of a natural gas pipeline is set to be 30 years, the network operator will be able to depreciate 1/30 of the pipeline's historical cost (including both their purchase price / construction costs and other costs associated with getting them ready for operation) plus regulatory adjustments, if any, every year.

9 NRA may consider the role of their network in context of European market, since national plans are inputs into the European Ten-Year Network Development Plan (TYNDP).



### INFLATION FACTOR

Inflation plays a role in costs, particularly as regulatory periods last several years. To account for this, typically official data on inflation in the respective country is used to reflect increased costs, e. g., 7.9 % in Germany in 2022[10].

### REGULATORY ACCOUNT

Another important determinant of natural gas regulation is the regulatory account. It is a feature applicable to most TSOs under a non-price cap regime, but not to TSOs under a pure price cap regime or merchant TSOs. With the MRA set, it is possible to charge the shippers (i. e., the customers of the TSOs) a fixed tariff for the service of transporting natural gas. This is particularly important as it provides clarity and transparency for shippers for the costs that can be expected during the regulatory period. As the overall gas consumption depends on a number of variables like weather, GDP growth, etc., it is not possible to know the exact transport volume in advance – the respective TSO will have to make assumptions of the final transport volume and, ultimately, the final revenue deviating from this. To make sure there is no volume risk for the TSOs and their shareholders, the difference in revenues is being taken and credited to the so-called regulatory account.

Together with changes in certain non-controllable costs (e. g. energy costs to run compressors) this revenue deviation generates either a plus or a minus on the TSOs regulatory account. In order to stabilise the network operator's earnings, the amount on the regulatory account at the end of every calendar year translates into either an increase or a decrease in the MRA over the next year(s). So, even if there is a year with lower earnings due to a decrease in demand, the TSO will be able to be compensated in the following years by keeping earnings that exceed the MRA of these years (and vice versa) until the regulatory account has been brought to zero.

### UNREGULATED (MERCHANT) ASSETS

It should be noted that even though most gas transmission and distribution networks are regulated, there are some networks that do not fall under the gas networks regulation. Those are often offshore pipelines that connect exporting countries from outside the EU with the EU market. If unregulated, there is no asset value credited to the RAB of the respective sponsor(s) and the tariffs are set freely in accordance with the market equilibrium, normally underpinned by long-term use-or-pay agreements with reputable shippers. However, existing merchant TSOs are often partly dependent on NRA decisions, with some regulations partly applicable to them.

## 4.2 FINANCIERS

### 4.2.1 EQUITY

Natural gas infrastructure has attracted a significant number of so-called 'institutional investors'. Most of these are companies that have fixed obligations like pension funds or insurance companies. These investors often have predictable cash needs towards their pensioners / clients under the relevant pension schemes or insurance products and need to find investment opportunities that provide both sufficient returns and stable cashflows. Infrastructure assets in mature markets are very well-designed for this, which explains the strong interest the natural gas infrastructure sector has been receiving for a long time now.

Inframation[11] provides a database which lists investments from institutional investors. According to its database, currently 434 different investors are invested in projects of natural gas transportation, natural gas distribution and LNG import terminals (EU plus UK, Switzerland and Norway). Over the last five years alone, 76 transactions have been closed (this includes M&A transactions).

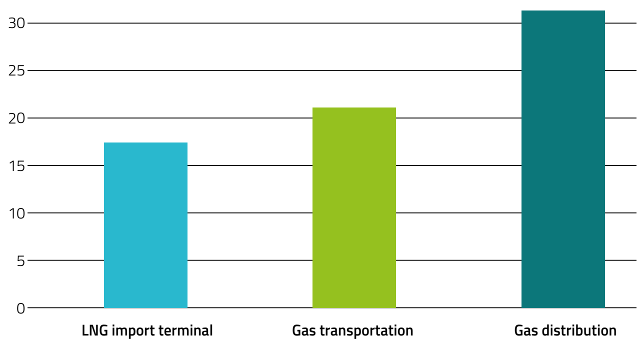



Figure 2: Transactions by asset type, Source: Inframation Group

In many of the transactions listed no deal volume was published. The available data suggests, though, that the overall volume of all transactions is in the range of EUR 75 bn, which sounds realistic given the large interest and the high deal flow the market has seen over the last years.

10 German National Bureau of Statistics

11 Inframationnews.com, registration required

Clearly, it can be said that institutional investors provide a significant share of the money that is invested into infrastructure and, in this case, natural gas infrastructure. The market for natural gas transmission and distribution appears to be an attractive space to invest, mainly due to the combination of low risk business model and, hence, stable returns of the targeted companies on the one side and the mature market environment on the other side. Given the volume of exposure institutional investors have, it would be difficult to replace these investors if circumstances in the investment environment changed.

### 4.2.2 DEBT

Regarding debt financing, the most important contributors apart from the capital market are commercial banks. They have been active in the infrastructure market for decades and energy infrastructure like natural gas grids or terminals is no exception. From a bank's perspective, infrastructure financings come with a number of advantages: they are mostly based on concessions or licences that provide for stable revenues of the underlying assets and a low risk, predictable cashflow on the level of the borrower. They are often indispensable for the orderly functioning of a society and part of a public service mandate that the local, regional, or national government has to implement itself or via a third party. They are eligible for capital reduction so that banks may lower their own funds requirement for an infrastructure loan by 25 % if it fulfils certain criteria[12]. Additionally, they offer the potential to smooth the effects from more cyclical sectors with a higher correlation to GDP growth and reduce the volatility of the assets in the loan portfolio.

According to data taken from Dealogic[13], an information provider for the financial industry, in the years 2013 – 2023 a total of 149 loan agreements have been signed that are related to natural gas infrastructure (either project related or general corporate purposes). This covers deals in the EU plus the UK, Norway and Switzerland, the average volume per deal reaching EUR 366 m. However, the data by no means include all loan agreements that were closed. Many TSOs and DSOs are not active on the capital market and, hence, are subject to much lower public disclosure requirements. They often prefer to keep their financing activities private, and banks do not report those deals without the consent of the borrower. That means the overall volume of loans that have been signed is significantly higher than the EUR 54.5 b that is shown in the Dealogic data for the last ten years. The overall picture shows the strong interest of the banking community in gas infrastructure assets.

Not all banks are in a position to finance gas infrastructure assets, however. Depending on the investment and risk guidelines, banks may struggle with financings whose tenor exceeds a certain duration. Furthermore, not every bank will manage to properly depict the stability of regulated cashflows in their pricing and/or rating systems. Additionally, some banks have investment policies in place that rule out loans in fossil-heavy sectors (see chapter 4.4.). Nonetheless, many banks are invested in natural gas infrastructure and will continue to be of core importance to many of the European TSOs, and therefore bank debt will remain a key source of liquidity.

Other players providing debt are also institutional investors, although their role is not as prominent as on the equity side. Also bonds and private placements are regularly issued, those are often taken by debt funds and asset managers.

12 This is stipulated in Capital Requirements Regulation (CRR) 501a with the objective to incentivise public and private investments in infrastructure.

13 Dealogic.com, registration required


## 4.3 BANKABILITY

The bankability of a financing is driven to a large extent as to whether or not the risks associated are acceptable to the financier from a risk management perspective but also whether the elements of the financing can be adequately inserted into a financier's internal systems. The key factors for the bankability of pipelines and terminals are described below.

### 4.3.1 PIPELINE NETWORKS

#### CONSTRUCTION RISK

Construction of an onshore natural gas pipeline is a risk that many banks consider to be relatively low given the straight-forward technical process behind it and the vast experience TSOs, OEMs and construction companies have gained. Laying pipes over or slightly below the surface is comparatively low risk. Given all the permits are in place and affected communities support the construction, there is little risk for delays. In terms of cost overruns, the main contributors are steel and labour costs. While labour costs within the EU are typically relatively stable and predictable, steel costs may be subject to volatility depending on market conditions. A TSO may either fix these costs by accepting a slightly higher price or earmark contingencies to cushion potential cost increases. Having said that, cost overruns are usually included in RAB and can therefore be recovered by tariffs.

Offshore pipelines and the corresponding subsea gas infrastructure is somewhat different. The key factor is the terrain over which the pipelines are laid. Water depth, seabed conditions and topography as well as, e. g., in the Baltic Sea, remnants of WW2 ammunition and other specificities/hazards make planning and construction of an offshore pipeline significantly more challenging than its onshore counterpart. Proven by many pipelines in the North Sea or partly also the Mediterranean Sea, it is certainly not impossible to successfully construct those pipelines. Financiers will carefully assess the respective risks and mitigants as part of their due diligence and may ask for additional measures to be taken in order to be in line with their own environmental guidelines.

In general, due to the, in comparison to other industrial projects, rather simple technology used and the experience of the involved parties, construction risks for onshore natural gas infrastructure is relatively low while construction risks for offshore natural gas pipelines depend very much on the topography of the sea and typically entail higher risks. All in all, construction risk is typically not a showstopper for bankability.

## MARKET RISK

The market for natural gas and its relevant transportation services is quite mature. Figure 3 shows the EU wide natural gas consumption from 1990 until 2022.

**Inland demand of natural gas, EU, 1990 – 2022**
(terajoules (Gross Calorific Value))

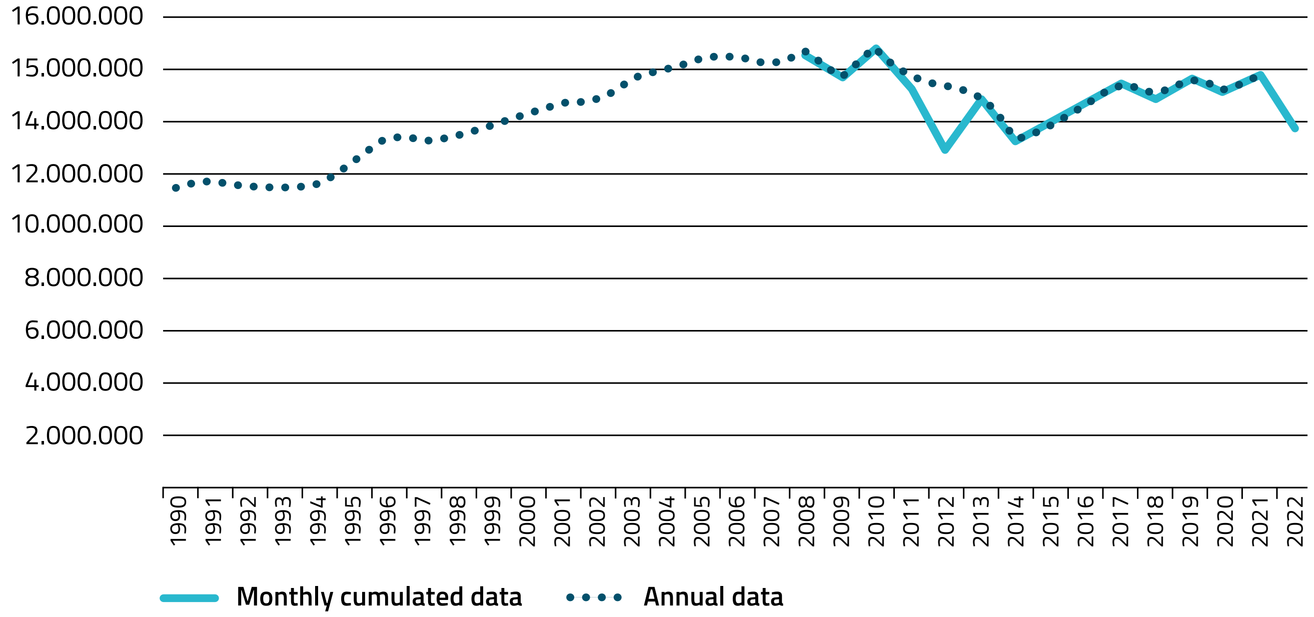



Figure 3: Development of EU domestic gas consumption, Source: Eurostat

Gas consumption in the EU has remained quite stable with a solid increase until 2008[14]. Given its wide use range from industrial feedstock to residential heating to electricity production and a significant production either in the EU itself or in neighbouring countries, many assets have been installed that need natural gas to operate and that are not easily (let alone cheaply) replaced.

The natural gas market so far also proved to be rather resistant to external shocks. Even though the war in Ukraine has resulted in a cut in gas supplies from Russia, the alternative supply sources for natural gas reduced the impact of removing the Russian supply source. The main shift was not a long-term demand decrease, although this did occur short-term through temporary EU security of supply regulation, but more a change in the supply chain with LNG cargoes from North America and the GCC region flowing into the EU, including into several new LNG receiving terminals. Hence, the main effects of the Russian invasion of Ukraine from an infrastructure financing perspective were a reversal of flow routes (from East to West changed to from West to East) and under- or overutilisation of certain assets which became less booked or congested amid the reshuffling of gas flows in the EU.

Nord Stream and other pipelines that run from Russia into the EU are either not in operation at all anymore or run on utilisation rates far below historical averages. It should be recalled that the regulatory account enables most TSOs to recover insufficient revenues or to give back extra revenues from/to the customers.

With ambitious plans for decarbonisation and new technological pathways such as electrification (e. g., in heat pumps), it is likely that the demand for natural gas will decrease in the future. This supports, where appropriate, the argument to repurpose a significant amount of pipeline and terminal infrastructure for clean hydrogen as those assets will, at a certain point in time when they can switch to clean hydrogen transport, no longer be necessary to transport the same level of natural gas with reduced demand for their service. This issue has gained attention from financiers in their due diligence and it is likely that investors will be more careful in selecting which assets to finance and on what molecule flow and market risk to bank on.

14 Ten new members joined the EU in 2004 and another three new members joined the EU between 2007 and 2013.



## REGULATORY RISKS

The largest contributor to bankability of pipeline projects is the strong and established regulatory framework in the EU in which TSOs operate natural gas pipelines. Banks and other long-term debt providers appreciate stable and predictable cashflows. The current regulation in the EU member states, particularly those that have a regulation based on a revenue cap, enables exactly this. In combination with a mature market, i. e., limited movements in demand and a well-working supply of natural gas, this creates an environment in which banks are able to assign good, mostly investment grade ratings to TSOs. The public mandate of a TSO's business is seen as risk mitigant and results in rating upgrades, another positive factor is the full or partly state-ownership of a TSO which is typically another upgrade trigger. Lastly, regulatory periods run several years and changes to the regulatory regime that would have impacted creditors in a noteworthy manner are scarce.

It is important to understand that banks are very regulated entities. Once a bank has established a certain procedure and system on how to evaluate financings and the banking authority has approved this, there is little to no room for discretion in the credit and risk management tools. Therefore, if financing structures are difficult to mirror in the internal systems, banks will either have to make their funds more expensive or they might even be forced not to enter a financing at all as they cannot match their better-off competitors. A predictable and easy-to-understand regulation of pipelines and other energy infrastructure is an advantage for a bank's credit analysis and subsequent loan approval.

## FINANCING STRUCTURES

Financing structures for pipeline projects depend mainly on the purpose of the financing, the three main ones being CAPEX (i. e newly built facilities/assets), refinancings, and acquisitions.

CAPEX are often financed by banks because they are well positioned to assess the regulatory regime as the key risk mitigant. A bank needs to understand the regulation and be able to reflect it in its credit systems. If that is the case, credit ratings of TSOs/DSOs or their investment projects will likely be investment grade for the bank itself and allow it to offer attractive margins. This exemplifies the importance of the regulatory scheme for energy infrastructure financings. Contrary to this, institutional investors like asset managers tend to have less capacities for due diligence work and like to operate in standardised structures. In practice, CAPEX projects are often financed with bank debt that has a tenor of 5 – 7 years based on financial covenants that work on a 'net debt to RAB' basis. Note that the 'net debt to RAB' covenant would not exceed 100 % and will typically range at max in the 90 – 95 % region.

CAPEX projects are often refinanced sometime after construction and commissioning are completed. These refinancings attract banks and institutionals, the main difference being that the latter often provide longer repayment tenors and offer very competitive margins. Often different tranches with different financing purposes are established, so both banks and institutionals provide money to the respective borrowers.

Acquisitions of existing assets are banks' arena. When bidding for an asset or even an entire company, equity investors need the security that their bid is backed by the debt side and they need binding offers from the debt providers for margins and fees of the loans as the basis for their own financial model. Institutional debt providers cannot match the due diligence speed of banks and are typically not able to support during the tender process.

## 4.3.2 IMPORT AND LNG TERMINALS

The EU is an importer of energy, natural gas being one energy carrier with a high import dependency. Apart from imports via pipelines, LNG receiving terminals serve as the main landing point for imports and have developed to be of core importance for the EU natural gas imports, particularly after the start of the Russian invasion of Ukraine in 2022. Several Member States, such as Germany or Finland after the Nord Stream and Balticconnector incidents in 2022 – 23, had to start or accelerate a program of building LNG terminals to make up for insufficient or absent pipeline gas flows. Italy as well is building new FSRU terminals (Floating Storage Regasification Unit) to increase gas import capacity. The construction of additional LNG terminals did not only address the immediate security of supply crisis but also contributed to a broader diversification of energy supply.

## CONSTRUCTION RISK

The technology behind an LNG import terminal is well established with proven technology in use and experienced contractors able to build such terminals. Naturally, delays and cost-overruns need to be addressed, particularly in the current scenario with distorted or disrupted supply chains and elevated inflation rates. Delays may also stem from permitting procedures as LNG terminals are situated in coastal areas, often close to important sites for biodiversity. The same will be the case for $H_2$ import terminals.

Terminal storage, where large tanks are used to store all kinds of energy carriers, including natural gas, are also a well-established technology. Whilst specifications vary (i.e., a tank dedicated to store natural gas cannot simply switch and store methanol instead), there is little technical complexity in the design of the individual tanks. LNG terminals and storage often complement each other as the former makes sufficient supply possible while the latter is a mean to balance supply and demand also from a timing perspective. Both tank farms and terminals bear comparatively low construction risks and are typically not a deal breaker for financiers when addressed properly in the financial set-up of the project.

#### MARKET RISK

The market for terminal services and gas storage follows the overall market dynamics. Regarding terminals, some are regulated whereas some are exempted[15] (Link). Wherever there is high demand for natural gas, there is an infrastructure in place to physically transport the molecule. Close to consumption centres and / or import and trading hubs, there is also demand for storage capacity. In Europe, the most important centres for terminal services and storage are the ARA region, Northern Germany, Northern France, the Spanish Mediterranean and Italy. All these areas provide large ports, are close to demand centres and well-connected to pipelines running inland and establishing a connection to further off-takers.

In addition to this, tank farms sometimes serve a specific industrial facility (e.g., a refinery or a petrochemical plant) and are integrated in its value chain. Also, some tank farms have anchor customers (often being identical to their shareholders) that contract a significant share of the capacity. This and the availability of storage for the products the market requests the most are good features to secure financing.

#### FINANCING STRUCTURES

Terminals in Europe are being financed on a long-term basis. The underlying contracts with customers that book the capacity of a terminal often run ten or more years. This and the customers' typically good credit rating provides a high degree of stability – it basically reduces the terminal's risk to its facility being operational. As long as the terminal operates and customers honour the contracts, cashflows are stable and predictable. Even though in reality things are slightly more complex, this is mainly what banks base their credit approval on. Financings may be closed on a long repayment tenor and then be refinanced after some years through investment funds, private placements or other sources.

Typical financings for storage operators are structured as a corporate financing and run between five and seven years. They often have a significant balloon repayment, which means a large part of the debt will not be repaid during the life of the loan but refinanced through a new loan (with an incentive for early refinancing due to margins rising over time). This balloon debt can be seen as a base leverage of a company and is accepted when several factors are present: the location of the terminal in one of the main trading hubs, potential integration into the value chain(s) of customer(s), storage capacity for the most requested products, etc. Although in practice storage contracts normally run around 2 – 4 years, well-run terminal operators are known to renew their contracts regularly. This provides the necessary comfort to banks to lend longer than most service contracts run. A requirement for the frequent renewal of service contracts is, naturally, a mature market with well-defined supply and demand patterns. There have also been financings on project / SPV level, but this is mostly an exemption.

### 4.3.3 UNDERGROUND $H_2$ STORAGE

The projects within the scope of RT2-Transmission and Distribution, include:

— Transmission and distribution pipelines for local, regional, national, and international transport and storage facilities;
— Marine storage and handling terminals in ports covering both existing as well as new terminals,
— Shipping covering deep sea and short-distance maritime routes,
— Inland distribution modes of transport including trucks, rail, barges, hubs and operational storage (such as bullets, tanks, containers, etc.).

The remit for Hydrogen Underground Storage lies with RT 5 – the Energy Roundtable, and specificities for this topic have not been included in this Learnbook. Nonetheless, the Transmission and Distribution Roundtable are aware of the interconnectivity of the infrastructure, including storage facilities, to enable hydrogen corridors and to create hydrogen value chains: for financial risk mitigation, projects should not be seen separately but in the broader context. As well as the work of RT-5 Energy Roundtable, the RT-2 members gladly acknowledge the recent establishment of **H2eart for Europe**, an alliance of storage system operators in Europe committed to accelerate the construction of underground hydrogen storage. The joint **Hydrogen Infrastructure Map**, developed as a requirement by EC at the Madrid Forum 2022 and now coordinated by ENTSOG, GIE, CEDEC, Eurogas, GEODE, GD4S in cooperation with the European Hydrogen Backbone, displays the prevalence of hydrogen storage projects within the hydrogen infrastructure network.

15 See GIE database for more details.

# 5 FINANCING OF A EUROPEAN HYDROGEN INFRASTRUCTURE NETWORK

This chapter outlines the differences between natural gas and hydrogen infrastructure financings and which barriers for the financing of a hydrogen transportation network currently exist. Sources of public financing are presented and options to overcome investment barriers are discussed. Furthermore, this chapter also investigates non-financial issues of financings such as Environmental, Social and Governance (ESG) aspects.

## 5.1 OBSTACLES AND GAPS

In **section 4.3** the bankability criteria for natural gas infrastructure financings have been outlined, which can be used as a means to compare and contrast with the bankability of hydrogen infrastructure financings. Investments in hydrogen transmission and distribution assets could generally be very similar to the ones in the natural gas market, but currently some important differences result in challenges that investments in hydrogen transportation infrastructure face.

#### HYDROGEN IS A NASCENT MARKET

The key difference between the two sectors is that although natural gas demand will likely decrease over the next decades, it currently is a very well-developed, mature wholesale market with large volumes being transported. Natural gas transmission and distribution is a large-scale activity with spot and long-term trading taking place, industry standards existing, and many different applications from industrial feedstock to residential heating to electricity generation being in place.

Therefore, established business models and value chains exist. In comparison to this, while hydrogen is widely used as feedstock in industrial applications already today, it is almost exclusively derived from natural gas via steam methane reforming. While the vast majority of this so-called grey hydrogen is being consumed very close to its place of production and, hence, traded volumes for hydrogen are negligible, hydrogen consumption as of today forms part of the value chain for natural gas. Clean hydrogen will create its own value chain independent of natural gas, but this will take time. Other applications are yet to find their place.

Figure 4 depicts that the market for low-carbon hydrogen looks promising but is still early stage.

**Use of low-emissions hydrogen rises significantly to 70 Mt by 2030 and extends to new applications such as in aviation and shipping.**

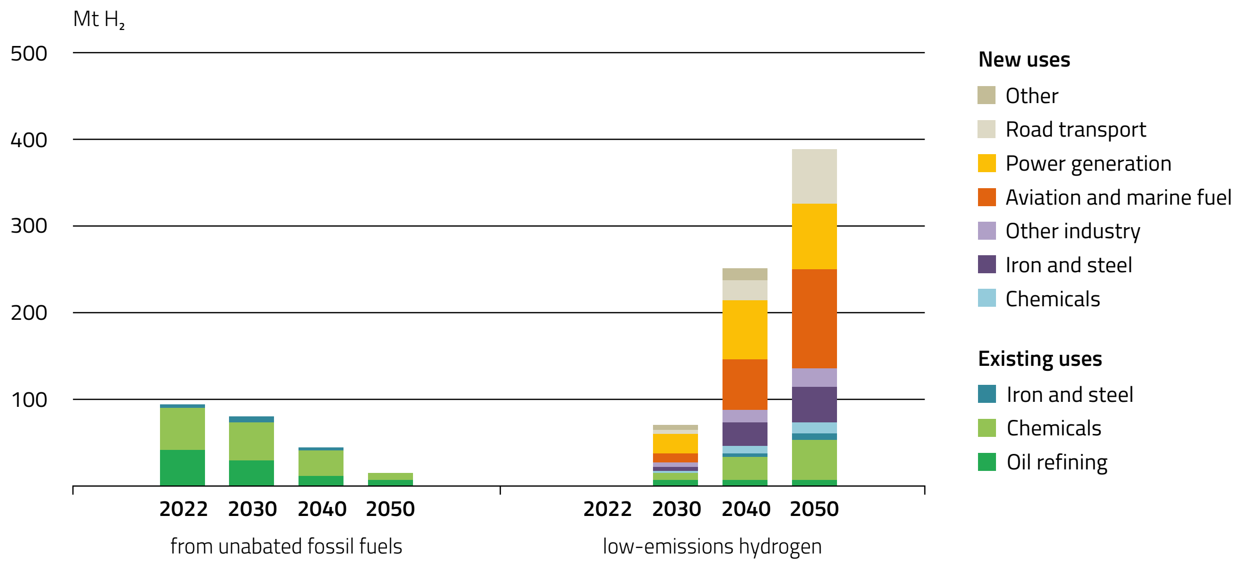



Figure 4: Low carbon hydrogen demand in a net zero scenarios, Source: IEA, Net Zero Roadmap, 2023

The view in the IEA's Net Zero Roadmap is very similar to many other forecasts about the hydrogen market. Until 2030, little amounts of clean hydrogen will be produced, transported and traded whereas in 2050 the share of hydrogen in the energy market will have increased significantly thanks to better economics and a wider adoption of hydrogen across all sectors. Depending on which scenario is taken as a baseline, absolute demand in metric tons differs to a certain extent but the general estimate is a strong rise in supply and demand and a hydrogen market that is far more mature. It should be noted, however, that the overall velocity of the market ramp-up for hydrogen not only depends on the willingness of participants along the value chain but also on political decisions how to incentivise the usage of clean hydrogen.

Not only will the size and value of the market develop, also industry standards, certifications, and the regulatory framework will undergo significant changes. As customary for nascent markets, the degree of uncertainty is high and relates to market players, technology, value chains and business models. It takes time to develop this and provide market participants along the potential value chains the security they need to make investment decisions. Investors that invest into clean hydrogen face a high degree of regulatory uncertainty but must base their calculations on a long investment tenor and a long amortisation period. This holds true particularly for infrastructure operators.

## POOR ASSET UTILISATION DURING MARKET RAMP-UP

Transmission and distribution of hydrogen is a service that depends on sufficient clean hydrogen being produced and consumed, which is, as shown above, clearly not the case currently or for the foreseeable future. Globally, only a handful of projects that target the production of clean hydrogen have been sanctioned[16], and some of these are targeting the investors' own demand[17], which means the hydrogen will not be traded but consumed in dedicated facilities very close to the point of production. There is a need for hydrogen infrastructure, the exact timing depending on the speed of the market ramp up, but currently incentives to invest are limited. It should be noted that one of the key parameters of infrastructure projects is to maximise asset utilisation. Furthermore, it is important to understand that investments in energy infrastructure do not make sense below a certain minimum capacity.

Planning tenors, development costs, labour, costs of construction, etc., result in relatively high base CAPEX and very long planning and permitting phases, so any TSO will want to avoid having an undersized network few years down the road.

As long as there is no large-scale production of clean hydrogen and no significant trading activity, there is no possibility for asset owners to bring their utilisation ratio to meaningful levels.

16 IEA, „Global Hydrogen Review", 2023, P. 65, stating that only 4 % of all announced low-carbon hydrogen production projects have taken FID

17 For example Holland Hydrogen I by Shell, which is fully targeting Shell's own demand in its Pernis refinery

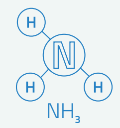
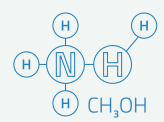


## FEW VIABLE BUSINESS CASES FOR CLEAN HYDROGEN

Neither form of clean hydrogen – renewable and low-carbon – is available in significant quantities which is due to a few reasons, the most important one being the significantly higher production costs as compared to classic, fossil-based grey hydrogen[18]. Naturally, many technological improvements can be expected over the next years with electrolysers becoming more efficient, electrolyser costs potentially decreasing due to scale effects, improvements in using otherwise curtailed renewable electricity, etc. Those improvements will lead to lower costs for clean hydrogen. Furthermore, with $CO_2$ emission trading and certificate prices increasing, the gap between fossil and clean hydrogen will narrow over time until it reaches break-even, eventually. When the cost parity between fossil fuels or feedstock and clean hydrogen is reached, depends largely on the sector. For example, green hydrogen that is supposed to replace grey hydrogen as a feedstock in refineries competes with natural gas whilst green hydrogen to be consumed in steel mills competes with coking coal (blast furnace route) or natural gas (direct reduction). Until cost parity has been reached in the respective sectors and demand has developed and increased, hydrogen infrastructure will need to be developed with public support.

## TECHNICAL AND INDUSTRY STANDARDS YET TO BE DEVELOPED

Every investor needs the asset to align with its technical specifications to enable the delivery on the promised financial return. Except for transport of hydrogen through pipelines there are still many uncertainties with regards to the technologies that might be used to import hydrogen.

| Hydrogen Carrier | Advantages | Challenges |
|---|---|---|
| **Ammonia**  <br>Liquid ammonia is stored at ambient temperature under high pressure or at −34 °C under atmospheric pressure.<br>$NH_3$ is currently the second most highly produced chemical globally, with a global manufacturing capacity of ~230 Mt annually.<br>Around 20 Mt per year of ammonia are traded globally. The main utilisation today is to produce fertilisers. Ammonia is produced through SMR (grey ammonia) and is responsible for ~5 % of global emissions. | • $H_2$ carrier with the highest number of export-oriented projects globally announced.<br>• It has an excellent $H_2$ density (18.6 MJ/kg).<br>• Easy to transport around the world in large quantities as it happens today.<br>• Attractive supply chain costs via the use of world-scale carriers.<br>• There are already existing infrastructure and many concrete plans to expand their capacity.<br>• Can be used not only as $H_2$ carrier but also as a feedstock to decarbonise fertilisers and chemicals.<br>• This carrier offers competitive costs if reconversion to gaseous $H_2$ is not needed.<br>• It is carbon-free. | • Toxic and flammable.<br>• Requires special handling and safety precautions, but the industry has wide experience in handling it safely.<br>• To be used as $H_2$ carrier, ammonia needs to be cracked back into $H_2$. This technology exists, but the number of commercial large-scale crackers is not numerous. IEA classifies $NH_3$ cracking with TRL 4.<br>• It produces $NO_x$ emissions when combusting $NH_3$ (e.g. transport and power applications). |
| **Methanol**  <br>As a liquid at room temperature, methanol is easy to store and transport.<br>The transformation back to $H_2$ encompasses $CO_2$ emissions | • Energy density slightly higher than ammonia (20.1 MJ/kg).<br>• Safer than hydrogen.<br>• Already being shipped today in large quantities and long distances.<br>• Transported at ambient conditions.<br>• It is widely available, commercially available fuel, and easy to obtain.<br>• Not only can be used as $H_2$ carrier but also as a feedstock for chemicals, and soon as a new green fuel in shipping. | • It is toxic, flammable and corrosive, but the industry has wide experience in handling it safely.<br>• It contains carbon and, to be climate neutral, the $CO_2$ source for producing methanol should preferably be biogenic, direct air capture, or industrial process.<br>• It requires large quantities of affordable $CO_2$ upstream, and it competes with bio-based feedstock for end products (e.g. olefins). |

18 BNEF, 2023

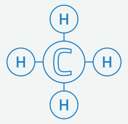
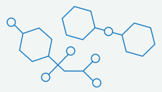
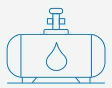
| Hydrogen Carrier | Advantages | Challenges |
|---|---|---|
| **Methane**  $CH_4$ <br><br> $CH_4$ can be produced by combining captured $CO_2$ with $H_2$ using the well-established Sabatier methanation process. It would be then transformed back to $H_2$ or, in some cases, used as methane with carbon capture | ▪ Makes up a large part of our energy supply worldwide today.<br>▪ Compatible with existing infrastructure (ships, terminals, pipelines, etc.).<br>▪ Different origins: e-methane, biomethane, fossil methane.<br>▪ $H_2$ gas is obtained from methane via different ways: SMR, ATR, and Pyrolysis. | ▪ The $CO_2$, or black carbon in the case of pyrolysis, released in the process has to be handled adequately (e.g. captured for storage, closed system with a return loop, etc.). |
| **LOHC**  $C_{14}H_{26}/C_{14}H_{14}$ <br><br> Liquid Organic Hydrogen Carriers (LOHCs) are organic compounds that can absorb and release $H_2$ through chemical reactions. According to IEA, LOHC has a TRL classification of 6–7. | ▪ By chemically bonding $H_2$ to a stable organic liquid carrier, this eliminates the need for compression and makes it safer and more cost-efficient to transport at ambient conditions.<br>▪ Existing oil infrastructure (ships, terminals, pipelines, etc.) can easily transport LOHC.<br>▪ Allows for an easy hinterland transport of $H_2$ (beyond the receiving terminal).<br>▪ Different options available.<br>▪ The energy need for reconversion can be significantly reduced with free or cheap heat supply (integration with industrials at import terminals). | ▪ Some LOHC carriers can be toxic and/or health-hazardous.<br>▪ Innovation and tests needed to continue improving efficiency.<br>▪ The preparation phase (hydrogenation) and reconversion phase (de-hydrogenation) are commercially available only at the pilot scale. Industry scale planned for 2025.<br>▪ Low hydrogen content by mass (but it allows handling big volumes and weights). |
| **Liquid Hydrogen ($LH_2$)**  $LH_2$ <br><br> $LH_2$ is stored at cryogenic temperatures (−253 °C) and commonly stored in a pressurised environment with low pressure (1–6 bar). | ▪ Highest energy density by mass (142 MJ/kg).<br>▪ $H_2$ is transported in high-purity form (lowest $H_2$ impurity).<br>▪ There is no need for conversion/reconversion in other chemicals.<br>▪ Energy consumption for transformation into gaseous $H_2$ is low. The cryogenic power of the gasification process could be (partially) recovered. | ▪ Costly and energy-intensive process. High-energy preparation phase (liquefaction).<br>▪ Given $LH_2$'s temperature of −253 °C, its overseas transportation presents a major technology challenge. Transport is viable for $LH_2$ vessels but is still in the pre-commercial phase, with limited capacity.<br>▪ The transport of large quantities of liquid $H_2$ overseas needs more effort on R&D in the short and medium term.<br>▪ Ships for transporting $LH_2$ are not yet commercially available.<br>▪ Highly flammable, but this is more a disadvantage of the carrier rather than a barrier for the development of the technology.<br>▪ $LH_2$ is subjected to boil-off loss. If the ship doesn't use hydrogen to propel its engine, then the boil-off will have to be vented into the atmosphere, generating hydrogen emissions. |
| **Compressed $H_2$**  <br><br> Compressed $H_2$ can be transported in gas cylinders or gas tubes with pressures between 200 and 500 bar. It is suited for short-distance transportation in the absence of pipeline infrastructure | ▪ The absence of any conversion step in its packing and unpacking processes could favour it enough to overcome the disadvantages in case of short-distance. | ▪ It has the lowest $H_2$ density among the carriers listed, penalising the long-distance shipping and storage steps.<br>▪ Highly flammable, but this is more a disadvantage of the carrier rather than a barrier to the development of the technology. |

Table 1: Advantages and challenges for commonly known $H_2$ carriers, Source: Learnbook on Hydrogen Imports to the EU Market



It is not yet clear what the energy carrier of choice will be when it comes to transporting hydrogen over long distances from outside of Europe and import it into the EU. Clearly, the most energy-efficient and cost-efficient method to transport hydrogen within the EU is via pipelines. This is likely true also for imports from North Africa and maybe even the GCC area. For longer distances, the main options are ammonia, methanol, LOHC, synthetic LNG or liquified $H_2$. Each of these technologies has its specific benefits. Today, it is difficult to predict which of these technologies will be adapted (it might be several of them) and what share of the market this technology will be able to claim – decisions on these issues will be shaped by not only cost considerations but also by climate and wider environmental as well as social considerations. Building an import terminal based on a technology that might prove to have a lower market penetration than others in a couple of years is a risk many investors do not want to take.

## 5.2 TARIFFICATION REGIMES

The main framework applicable to hydrogen infrastructure tariffs are provided in the upcoming Hydrogen and Decarbonised Gas Market Package proposed by the European Commission in December 2021 and adopted in First quarter of 2024[19,20].

### 5.2.1 TOWARDS A HTNO TARIFF NETWORK CODE (HTAR NC)

The Regulation provides that the EC will be tasked with supplementing it with delegated acts to develop NCs (Art. 72(1) REG). They will be prepared for HTNOs, including one on tariffs (Art. 72(1)(e) REG), which will most likely mirror the Tariff Network Code (TAR NC) regulating gas TSOs since 2017; the TAR NC implementation has facilitated transparency on gas TSO tariffs across Europe and improved convergence of practices, but it did not aim to fully harmonise national practices. While this Hydrogen Tariff Network Code (HTAR NC) is only envisaged for future years, the Directive already sets the objective of avoiding cross-subsidies (Art. 78(1)(m) DIR). Between the expected entry into force of the Package (2024) and the future HTAR NC entry into force at an undefined date at the moment, the provisions set out in the Package will likely prevail for HTNO tariff practices[21]; within this range of possibilities set by the Package, a significant role will be left for individual NRAs to innovate and define tariffs in view of the future requirements from the HTAR NC. The HTAR NC will also develop principles on the reference price methodology for HTNOs, on tariff consultations and publications – including on HTNO regulated revenue – and on reserve prices for standard HTNO capacity products[22].

19 European Commission, 2021, Commission proposes new EU framework to decarbonise gas markets, promote hydrogen and reduce methane emissions.

20 The Directive clarifies that NRAs' role in modifying tariffs is excluded in case nTPA applies to the HTNO (Art. 79(1) DIR). NRAs will also make sure that tariffs include the remuneration of the HTNO owner in case of an independent hydrogen network operator (Art. 78(3)(d) DIR). Where applicable, NRAs may approve provisional HTNO tariffs in case of delays in setting such tariffs (Art. 79(1) DIR). Complaints against NRA decisions on tariff or tariff methodologies may be issued within at most two months (Art. 79(2) DIR).

21 For example, based on Art. 89(1) REG, Art. 3 REG will apply from six months from the entry into force of the Regulation, and it states general principles, such as '(c) tariffs charged at the entry and exit points in the natural gas system and in the hydrogen system shall be structured in such a way as to contribute to market integration, enhancing security of supply and promoting the interconnection between natural gas networks and between hydrogen networks […].'

22 While the EC's Package proposes to introduce dedicated discounts for renewable and low-carbon gases on gas TSO networks, it is unclear at this stage whether a future HTAR NC will mirror these incentives for renewable (RE) and/or low-carbon hydrogen (LC), e. g., by way of certification through guarantees of origin (GOs).

## SPECIFIC CONSIDERATION FOR TARIFF RULES HTNO INTERCONNECTION POINTS (IPS)

The Regulation indicates that the EC may set out guidelines[23] on details of tariff methodology applicable for gas cross-border trade[24]: while such guidelines are originally for gas TSOs, the Regulation stipulates that the European Network of Network Operators for Hydrogen (ENNOH) will give its opinion on such guidelines (Art. 59(2) REG, ref. to Art. 74 REG), in case they are transposed for HTNOs[25].

It is also likely that the experience from the European gas market on NC implementation at IPs will prevail regarding the allocation of capacity at HTNO IPs (Art. 7(8) REG), and with respect to the corresponding IP tariffs. The Capacity Allocation Mechanisms Network Code (CAM NC) for gas TSOs is articulated around the default approach of EU-wide standardised capacity auctions. The TAR NC complements the CAM NC regarding auction tariff principles for gas TSOs[26].

## THE TRADITIONAL ROLE OF NRAs WILL BE KEPT FOR HTNOs

The Directive clarifies that, subject to NRA's approval, HTNOs should publish and provide transparent (Art. 42(1) DIR), efficient, and non-discriminatory rules on tariffs for connection of different customers to the HTNO network: hydrogen storage facilities, hydrogen terminals, and industrial customers[27]. More generally, NRAs will play for HTNO tariffs a similar role to the one they play towards gas TSO tariffs.

## 5.2.2 TIMELINES REGARDING HTNO TARIFFS IN THE EC'S PACKAGE

A first important date is 1 January 2031, when hydrogen network operators – for transmission and distribution – or their respective NRA must publish information (Art. 66(2) REG) on tariff derivation, tariff methodologies, and tariff structure according to the Regulation. This is to facilitate transparent, objective, and non-discriminatory tariffs for HTNOs and Hydrogen Distribution Network Operators (HDNO )[28]. For a natural gas user, the transition to hydrogen will not only depend on tariff comparison between hydrogen and gas networks, but will also be based on the full cost of hydrogen (from production to supply), and on other parameters to anticipate (such as legal deadlines for specific sectors to achieve their transition, or the evolution of the trading of guarantees of origin).

However, the date of 1 January 2033 constitutes the real pivotal moment for HTNOs regarding tariffs. Some rules will apply either from that date or earlier in case of regulated TPA for hydrogen networks. Other rules will apply only from 1 January 2033. The following developments describe these two sets of rules.

23 Reference for the gas TSOs is in Art. 74(3) REG: '3. The Commission is empowered to adopt delegated acts in accordance with Article 80 to supplement this Regulation by establishing guidelines in the following areas: […] (d) details of tariff methodology related to cross-border trade of natural gas, in accordance with Articles 17 and 18.' However, to our knowledge no such guidelines on gas TSO tariffs were developed by the EC, and the TAR NC constitutes the framework for gas TSO tariffs, which includes tariffs applicable for cross-border trade.

24 Tariffs for cross-border trade are charged at IPs and for a user they correspond to the sum of the cost of exiting a TSO's national network plus the cost of entering another TSO's national network. Such IP tariffs are simply derived from the same methodology as the one decided on by the national regulator for other network points (Art. 6(3) TAR NC). On preserving cross-border trade, several provisions applicable for gas TSOs give a framework for IP tariffs, such as the objective not to distort cross-border trade (Art. 7(e) TAR NC), with special attention paid to some tariff parameters called multipliers (Art. 28(3)(a) TAR NC) and to the possibility of granting derogations (Art. 37(1)(c) TAR NC).

25 ENNOH will be established following EC's Package requirements as the future European entity bringing together the national HTNOs (Art. 57 REG).

26 Based on the EC Package, which considers auctions as a possible tool to allocate HTNO capacity, auction tariffs may become the standard tool for HTNO IP tariffs (Art. 7(8) REG).

27 The Directive also stipulates that, in case an integrated or independent HTNO does not execute an investment which was however scheduled in the Ten-Year Network Development Plan (TYNDP), for reasons which are not beyond the HTNO's control, the NRA should implement decisions to ensure that the investment is realised, and it should adjust the HTNO tariffs accordingly (Art. 55(8) DIR).

28 This rule of tariff transparency for hydrogen network operators from 1 January 2031, interpreted in combination with the following rule of default rTPA by 1 January 2033, has consequences for hydrogen project developers. Until 2030, it is likely that a project developer will need to negotiate network tariffs, with few obligations on the network operator regarding these tariffs; In 2031 – 32, some guarantees on network tariff transparency will be provided to the project developer but rTPA will still not be mandatory. From 2033, the default principle of rTPA and increased transparency on tariffs are intended to provide a level playing field that should accelerate the rise of hydrogen production projects.



## RULES THAT WILL APPLY NO LATER THAN 2033 OR EARLIER IN CASE OF REGULATED TPA FOR HYDROGEN NETWORKS

Many national and regional (sub-national) rules and obligations applicable for gas TSOs shall also apply to hydrogen networks (Art. 7(8) REG), as soon as regulated Third-Party Access (rTPA) applies to hydrogen networks in a specific Member State, and in any event no later than 1 January 2033. The Directive indicates that rTPA should be the default rule for all hydrogen networks in the long-term (HTNOs and HDNOs), and that negotiated TPA (nTPA) is only allowed until 31 December 2032 (Art. 35(4) DIR)[29].

First, some rules will become applicable at all HTNO points (Art. 7(8) REG), either from 2033 or earlier in case rTPA applies for HTNOs. HTNO tariffs will have to be cost-reflective and transparent (Art. 17(1) in combination with Art. 7(8) REG) and may be recovered through auctions.HTNO tariffs will also need to ensure cost-efficiency and HTNO investments (Art. 17(1) i. c. w. Art. 7(8) REG). Tariffs will have to be set separately at each entry point and each exit point (Art.17(1)REG) of the HTNO, which will exclude path-based tariffs[30]. NRAs and HTNOs will cooperate to amend HTNO tariff methodologies in case they hamper the convergence of wholesale hydrogen prices (Art.17(2) REG).

Second, specific rules will become applicable at HTNO IPs only (Art. 7(8) REG), either from 2033 or earlier in case rTPA applies for HTNOs. Tariffs at HTNO IPs should not represent barriers (for cross-border) trade in Europe, and they should be cost-reflective. In case HTNO IP tariffs are too high, they might be considered a barrier to trade, since hydrogen traders might not be able to take advantage of difference in wholesale prices of adjacent markets (the so-called 'hub spreads')[31].

- The future HTAR NC will set out rules for HTNO IP tariffs (Art. 72(1)(e) REG). For this purpose, NRAs will consult one another and stakeholders, and will duly take into consideration these views prior to approving the methodology for HTNO tariffs at IPs. NRAs will send the methodology intended for decision to the Agency for the Cooperation of Energy Regulators (ACER) (Art. 7(8)REG).
- The draft Regulation provides that, by way of a derogation, NRAs may decide to set HTNO IP tariffs at zero, or to set auction reserve prices at zero (Art. 7(8) REG) in case capacity is auctioned at IPs[32].
- NRAs may also request ACER's factual opinion (Art. 7 (8) REG) on the HTNO IP tariff methodology[33].
- In addition, the Directive requires that, for HTNOs under rTPA and for projects not covered by the Projects of Common Interest (PCI) list (Art. 59(1) DIR i. c. w. Art 7(8)REG), the financing of HTNO IP infrastructure may be reflected in HTNO tariffs, subject to NRA approval[34].

Third, hydrogen market mergers are envisaged in the Regulation, which intends to transpose gas TSO practices to HTNOs.

- At the cross-border level, the Regulation sets out that relevant NRAs may merge adjacent hydrogen entry-exit systems (Art. 17(4) i. c. w. Art 7(8) REG) while removing tariffs charged at the former HTNO IPs. Public consultations would be run by the NRAs or HTNOs, and they might be followed by an NRA decision to apply a common HTNO tariff in the merged system and an inter-HTNO compensation (IHC) mechanism to recover revenues missing after removing former IP tariffs.
- At the national level, in case a Member State is made up of several entry-exit systems or of one entry-exit system with several HTNOs, the NRA may decide that a uniform HTNO tariff will apply nationally (Art. 17(5) REG), subject to the approval of a network plan and to the implementation of an IHC mechanism.

29 In particular, hydrogen network users should be informed as to the impact from the transition from nTPA to rTPA on tariffs (Art.35(5) DIR).

30 A consequence is that any hydrogen volume entering an entry-exit system will be available for trade on the wholesale market and may exit the system at any exit point, which facilitates a liquid market and avoids that some hydrogen volumes in the HTNO system are not available for trade.

31 There has been a convergence in gas hub prices, especially in North-West Europe, in recent years until the disruptive effect of the gas crisis which began in 2022. This convergence went together with growing market liquidity and the improving easiness for a trader to make profitable arbitrage decisions. Considering that the legal framework for hydrogen networks will be similar to the one for gas networks, due to the Package provisions, the same stages in development may reasonably be expected for hydrogen: first, limited price convergence, then hub spreads closely related to HTNO IP tariffs in future years, at least in some European regions.

32 The Directive indicates that, **from 1 January 2033**, all concerned HTNOs must set up an Inter-HTNO Compensation (IHC) mechanism in the event no tariffs are charged at IPs, subject to an extensive consultation by relevant HTNOs (Art.59(3) DIR); if the concerned HTNOs can't agree on the IHC by 31 December 2035 (Art.59(4)DIR), the concerned NRAs will be tasked with finding an IHC agreement by 31 December 2037 (if not, ACER will decide). Details of the IHC will be set out in the HTAR NC (Art.72(1)(c) REG). We interpret these provisions as implying that, in case zero tariffs are decided by NRAs at HTNO IPs **prior to 2033**, there will be no obligation yet to set up an IHC mechanism. Regardless of the date, this option of charging no tariff at IPs refers to a situation where HTNOs remain in different entry-exit systems connected through IPs with zero tariffs or reserve prices; it is different from the option where a market merger into one entry-exit system is set up, where IPs disappear because they are not bookable any longer.

33 ACER should inform the EC if so, and take into account principles such as cost-reflectivity, appropriate return for investments, non-discrimination, efficient trade, and competition (Art.7(8)REG).

34 A Cross-Border Cost Allocation (CBCA) might be set up for NRA approval in case of a substantial gap between benefits and costs of the hydrogen infrastructure project.

### RULES THAT WILL APPLY NO LATER THAN 2033

The following rules will enter into application no later than 2033, regardless of whether an rTPA regime applies before that date.

First, from 2033, hydrogen networks (HTNOs and HDNOs) will need to be organised according to entry-exit systems (Art. 7 (6) REG), and hydrogen trading should be possible through a virtual trading point. It means that path-based tariffs will be prohibited for both HDNOs and HTNOs from that date.

Second, by 2033, as for natural gas TSOs, physical exchange of hydrogen will be optionally implemented at HTNOs' entry points from or exit points to third countries (Art. 3 (d) REG).

Third, with the deadline for implementing HTNO unbundling in 2033, HTNO tariffs will need to comply with the unbundling rules (Art. 5 REG), which will prevent cross-subsidies among energy carriers. Unbundling of accounts will apply, which means separate Regulatory Asset Bases (RABs) for hydrogen, natural gas, and electricity assets. In addition, the Directive clarifies that any derogation from the default legal unbundling applicable for HTNOs vis-à-vis gas or electricity DSOs or TSOs should be granted after considering, inter alia, the tariff impact of such derogations (Art. 69 (4) DIR)[35].

Fourth, two tariff mechanisms are retained by the Package even after 2033 as possible flexibility options. They will be options to overcome possible issues with HTNO and/or gas TSO financing.

- A first option is the Inter-Temporal Cost Allocation (ITCA) mechanism (Art. 5 (3) REG)[36]. Some of the HTNO tariffs that should be charged on early HTNO users might be charged later on future users, subject to NRA approval and a potential State guarantee, in case this postponement is recognised as a way to alleviate tariffs for early users and facilitate their transition to hydrogen[37].
- A second option is that HTNO tariffs might be complemented by non-HTNO tariffs to pay for HTNO costs, by way of a dedicated charge allowing financial transfers (Art. 5 (4) REG). In contrast with the ITCA option, where HTNO costs are paid by HTNO users, the option of financial transfers implies that gas TSO users would for example be charged an additional levy – or dedicated charge – that would be transferred to the HTNO. This solution would help HTNOs remain economically viable, especially at early stages of their activity[38]. The draft Regulation provides that the dedicated charge would be borne only by gas TSO exits to final customers located in the same Member State as the concerned HTNO[39]. Several conditions would apply for such transfers[40]. In contrast to the ITCA, recommendations from ACER on the dedicated charge and financial transfers would not be mandatory and may cover topics such as the size and maximum duration of the transfer (Art. 5 (6) REG), or the criteria for charging the dedicated charge on final consumers[41].

35 In case the assessment concludes that a derogation will have a detrimental effect on tariffs or other key parameters, the Directive requires that the derogation from legal horizontal unbundling be withdrawn (Art. 69 (4) DIR).

36 See also section 5.3.2. below on the so-called 'amortisation account' proposed as the German version of ITCA.

37 Without the ITCA, it is possible that cost-reflective tariffs on a limited number of early adopters of hydrogen would result in prohibitive HTNO tariffs. The draft Regulation stipulates that, no later than one year after the entry into force (EIF) of the Regulation, ACER shall issue recommendations for gas TSOs and DSOs, hydrogen network operators, and NRAs, regarding the ITCA (Art. 5 (6) via Art. 7 (9) REG). Assuming that EIF of the Regulation might be in mid-2024, ACER would be mandated to issue these recommendations before mid-2025. The Regulation also tasks ACER with updating these recommendations at least every two years. A dedicated hydrogen Network Code on ITCA will be published (Art. 72 (1) (g) REG).

38 This option of a dedicated charge would require a derogation from another default principle prohibiting financial transfers between separate regulated services (Art. 5 (2) via Art. 7 (9) REG). The NRA would have to assess in advance the pros and cons of this dedicated charge, by considering its impact in terms of cross-subsidies and cost-efficiency, and then approve the whole mechanism before its application (Art. 5 (4) via Art. 7 (9)).

39 This means that cross-subsidies between a gas TSO in one Member State and a HTNO in another Member State would not be allowed. Transparency on the dedicated charge and financial transfer would be necessary, by publishing the used methodology 30 days prior to their implementation (Art. 5 (4) via Art. 7 (9) REG). It would be mandatory to notify the EC and ACER, in case this second option is adopted in a Member State.

40 Conditions of applicability of the dedicated charge and financial transfers include: the need for the HTNO to charge tariffs beside collected transfers from the gas TSO, the requirement that the sum of collected revenue through HTNO tariffs and financial transfers from the gas TSO does not exceed the regulated revenue of the HTNO, and the obligation that the financial transfer is of a limited duration (no longer than one third of the remaining depreciation period of the infrastructure concerned) (Art. 5 (5) via Art. 7 (9) REG).

41 While financial transfers are mostly envisaged to reduce HTNO tariffs at the start of their activity, in our interpretation, transfers from HTNO to TSO might not be excluded to alleviate gas TSO tariffs in coming decades, when few gas customers remain (Recital 33 DIR).



Fifth, principles applicable to gas TSOs on capacity allocation mechanisms (CAM), congestion management procedures (CMP), and balancing will also apply to HTNOs from 2033 (Art. 10 and 13 via Art. 7 (9) REG).

Sixth, by 2033, HTNOs will also have to publish their tariffs at every network point on the future transparency platform hosted by the European Network of Network Operators for Hydrogen (ENNOH) (Art. 7 (9) REG).

Until this requirement for tariff publication on the ENNOH website is set out in a future NC, ENNOH might provide links to HTNOs' websites.

Finally, in case of quality issues restricting cross-border flows on HTNO networks, investment costs to solve such restrictions should be included in HTNO tariffs from 2033 (Art. 55 (7) REG).

### 5.2.3 HYDROGEN TARIFFS AND PRICES FOR NON-HTNOs IN THE EC'S PACKAGE

Specific rules for tariffs at hydrogen storage facilities and import terminals operated under third-party access are also mentioned in the Package[42]. Transparent, objective, and non-discriminatory tariffs (Art. 34 (6) REG) should apply at hydrogen storage facilities and import terminals. Infrastructure under rTPA should provide information on tariff derivation, tariff methodology, and tariff structure. The Directive also insists that hydrogen storage and import terminal tariffs should be subject to NRA approval – but can't be modified by the NRA if nTPA applies (Art. 79 (1) DIR); tariffs should be published prior to their entry into force (Art. 78 (7) (b) DIR).

The Directive stipulates that transparency on hydrogen supply tariffs and prices (Art. 11 (5) DIR) should also be ensured by suppliers for final customers. It includes information on the tariff name (Annex I 1.2. (c) DIR).

42 For example, tariffs at hydrogen storage facilities and import terminals should not be arbitrarily higher when contracts are signed under non-standard start dates within a gas year or with a shorter duration than a standard contract on an annual basis (Art. 8 (4) REG).

## 5.3 FINANCING OPTIONS

It has become clear that securing financing for hydrogen infrastructure projects is currently challenging. Nonetheless, if a hydrogen economy shall evolve in the EU, a hydrogen transportation network is indispensable, so a solution to the problem of financing is needed.

There are several options existing or under discussion that already contribute or could do so in the future to securing financing.

### 5.3.1 EU FUNDING PROGRAMS

This section provides an overview of the main EU financial programs and initiatives that may apply to hydrogen infrastructure within the scope of the Roundtable for Transmission and Distribution. To accelerate the European hydrogen economy, project promoters may seek a combination of public and private funding sources to ensure its development.

The following overview includes some of the public financing options available for hydrogen project promoters that offer financial support. To ensure the most up-to-date information, sources include the following official EU platforms:

- **The Hydrogen Public Funding Compass** is an online guide for stakeholders to identify public funding sources for hydrogen projects and it provides information on all the EU programmes and funds (2021 – 2027) that are relevant for the sector.
- **The European Hydrogen Observatory** (former Fuel Cells & Hydrogen Observatory) is an initiative by the Clean Hydrogen Joint Undertaking and an open platform providing data and up-to-date information about the European hydrogen sector..
- Other referenced sources are included for each of the programmes / initiatives below. In addition, each of the following includes a brief description and are tagged to identify the type of funding or support. The main features of these options are also summarised in tabulated format within this section. Where information is not available, n/a is included in the table.

In many cases, there are opportunities to obtain funding from several EU funding programmes in combination. Where this is possible (in the absence of double funding of the same projects costs), the information is provided in the table.

It should be noted that other financial programmes may be available but are not listed as they may not be directly applicable for hydrogen pipelines and terminals.

**MANY OF THE FUNDING OPPORTUNITIES LISTED BELOW ARE FINANCED BY THE 2021 – 2027 MULTIANNUAL FRAMEWORK.**

## CONNECTING EUROPE FACILITY – ENERGY

https://cinea.ec.europa.eu/programmes/connecting-europe-facility/energy-infrastructure-connecting-europe-facility-0_en

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES
- PROCUREMENT

The Connecting Europe Facility for Energy (CEF-E) is a funding instrument for targeted infrastructure investment at European level. It supports the implementation of the Regulation on Trans-European Networks for Energy (TEN-E), which is focused on linking the energy infrastructure of EU countries. It may fund cross-border hydrogen transmission & distribution projects, storage and large-scale electrolysers (>100 MW of capacity).

## EUROPEAN REGIONAL DEVELOPMENT FUND

https://ec.europa.eu/regional_policy/funding/erdf_en

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES
- TECHNICAL ASSISTANCE (for project promoters)

The European Regional Development Fund (ERDF) is part of the EU's Cohesion Policy. ERDF supports innovation and entrepreneurship in the transition to a climate-neutral economy. REACT-EU is providing additional funds to ERDF. Some regions may allocate ERDF funds to hydrogen projects as part of their clean energy strategies.

## HORIZON EUROPE

https://research-and-innovation.ec.europa.eu/funding/funding-opportunities/funding-programmes-and-open-calls/horizon-europe_en

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES
- PROCUREMENT
- TECHNICAL ASSISTANCE (for project promoters)

Horizon Europe 2021 – 2027 is the EU's key funding programme for research and innovation. Pillar II and III of Horizon Europe are focused on the deployment of low-carbon industry applications and breakthrough technologies, including hydrogen. It must involve the research and innovation element. The Clean Hydrogen Partnership is a public-private initiative under Horizon Europe that aims to accelerate the development of a clean hydrogen economy in Europe. It may involve funding opportunities and collaboration with industry stakeholders.

## INNOVATION FUND

https://climate.ec.europa.eu/eu-action/eu-funding-climate-action/innovation-fund/what-innovation-fund_en

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES
- TECHNICAL ASSISTANCE (for project promoters)

One of the world's largest funding programs for the demonstration of innovative low-carbon technologies. The fund finances demonstration projects on innovative production and use of low-carbon and renewable hydrogen at pre and commercial scale, with the aim of bringing it to market. The Commission will also extend the Innovation Fund pilot auctions as a platform to interested countries of the EEA.

## INVESTEU

https://investeu.europa.eu/index_en?prefLang=nl

- FINANCING (loan/guarantee)
- TECHNICAL ASSISTANCE (for project promoters)

InvestEU provides a budgetary guarantee to the EIB Group and selected implementing partners with the aim to facilitate access to finance for riskier projects, including renewable hydrogen production, on-site storage, transport refuelling infrastructure and critical infrastructure supporting hydrogen deployment. It finances sustainable infrastructure; research, innovation and digitalisation; SMEs; and social investment skills.

## MODERNISATION FUND

https://modernisationfund.eu/

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES

The Modernisation Fund is a fund supporting 10 lower-income EU countries' transition to climate neutrality through the modernisation of their energy systems and improved energy efficiency to achieve their climate targets and the objectives of the European Green Deal. It supports investments in energy storage, generation and use of renewable, and energy networks.

## RECOVERY AND RESILIENCE FACILITY

https://commission.europa.eu/business-economy-euro/economic-recovery/recovery-and-resilience-facility_en

- FINANCING (loan/guarantee)
- GRANTS / SUBSIDIES

The Recovery and Resilience Facility (RRF) is the centrepiece of the EU's recovery plan of the REPowerEU Plan and NextGenerationEU. Its goal is to make EU economies and societies more sustainable by supporting green and digital transition. Project financing depends on what each EU country has included in its plan. The RRF is a temporary instrument.

## IMPORTANT PROJECTS OF COMMON EUROPEAN INTEREST (IPCEIs)

https://ec.europa.eu/commission/presscorner/detail/en/ip_24_789

- GRANTS / SUBSIDIES

Where private initiatives supporting breakthrough innovation and infrastructure fail to materialise because of significant risks such projects entail, EU State aid rules enable EU countries to jointly fill the gap with an IPCEI (ambitious, cross-border, integrated projects, important due to their contribution to EU objectives). Hy2Infra (the third H2 IPCEI wave) is dedicated to hydrogen-related infrastructure (pipelines, ports, and storage facilities). Previous H2 IPCEI waves also included hydrogen infrastructure projects. On 15 February 2024 the EC adopted its decision regarding the IPCEI Hy2Infra that was jointly prepared and notified by seven Member States: France, Germany, Italy, the Netherlands, Poland, Portugal, and Slovakia.

IPCEI Hy2Use and Hy2Tech are the H2 IPCEIs waves launched prior to Hy2Infra, both to address the hydrogen value chain. Hy2Use focuses on projects aimed at industrial uses . Hy2Tech is focused on the technologies to produce and distribute/sore hydrogen including therefore hydrogen-related infrastructure projects. A fourth and final H2 IPCEI (Hy2Move) covering applications of hydrogen in mobility sectors was launched in May 2024.[43]

43 Many national state funded programmes/schemes for $H_2$ projects. These are numerous and have to be compliant with EU State Aid rules (notably GBER and CEEAG)

| Name | Objectives | What type of hydrogen related actions can be funded | Funds available (in total, not exclusively for $H_2$) | Financing details | Funding process | How to apply and when | Stated synergies with other funds/finances? |
|---|---|---|---|---|---|---|---|
| CEF-E | Supports the implementation of the Regulation on Trans-European Networks for Energy (TEN-E) | Demonstration projects, studies, and co-financing of development of energy infrastructure, esp. missing cross border links, to remove bottlenecks or deploy EU-wide systems. Transmission pipelines for hydrogen, giving access to multiple network users on a transparent and non-discriminatory basis, which mainly contains high-pressure hydrogen pipelines, but excluding pipelines for the local distribution of hydrogen. The reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances with the objective of injecting the hydrogen. Newly constructed assets or assets converted from natural gas dedicated to hydrogen, or a combination of the two. | CEF-E has total budget of € 5.84 billion, out of which 15 %, subject to market uptake, should be allocated to cross-border renewable energy projects. | CEF is implemented through a mix of grants, procurement and financial instruments. The grant support is provided in the form of lump-sum payments- reimbursement of costs actually incurred by the beneficiary. The disbursement of grants are governed by grant agreements and by Title VIII EU Financial Regulation. | Project of Common Interest (PCI) status is a pre-requisite for any CEF-E funding. | The project proposals become candidates for the status of PCI by submitting their project proposals to the dedicated Regional Groups for assessment through responding to a number of Commission public calls. | An action that has received a contribution under CEF may also receive a contribution from any other Union funding programme, provided that contributions do not cover the same costs. |
| ERDF (as part of the EU Cohesion Policy funds) | Increases cohesion in EU by reducing economic, social and territorial disparities between regions and supporting the full integration of less-developed regions with the EU internal market through grants and financial instruments. | For the new programming period 2021–2027, hydrogen transmission and distribution projects may be part of the funding envelope. | € 191 billion | Specific target of 30 %, and to support innovation and entrepreneurship in the transition to a climate neutral economy. | Funding hydrogen projects will depend on priorities identified in the national and regional programmes. Fund implemented by the relevant national and regional authorities in line with the shared management approach | Conditions of application to ERDF programme identified in the calls published by the managing authorities in the EU countries. | n/a |
| Horizon Europe | Projects generally involve a research and innovation element. Pillar II and III of Horizon Europe: deployment of low carbon industry applications and breakthrough technologies, including hydrogen | Pillar II – global challenges and European industrial competitiveness, CLUSTER 5: Climate, Energy & Mobility: The Clean Hydrogen Partnership – Focus on production, distribution and storage of clean hydrogen to supply hard-to-decarbonise sectors such as heavy industries and heavy-duty transport applications. The design, development and diffusion across Europe of hydrogen valleys is a flagship priority of the Clean Hydrogen Partnership. | Total budget € 95.5 billion, Clean Hydrogen Partnership budget billion € 1 | The Commission provides funding in forms of grants, prizes and procurement to excellent researchers to promote their activities. It also provides funding to develop research infrastructure. | The Clean Hydrogen Partnership is funded by Horizon 2020. | Funding under Horizon Europe is done through open, competitive calls for proposals (also for European Partnerships and missions), as specified in the biannual work programmes. | n/a |
| Innovation Fund | One of the world's largest funding programmes for demonstration of innovative low-carbo n technologies. Covered by Annex I to the EU ETS Directive. It is not a research programme. | Hydrogen transmission and distribution projects can be funded either indirectly or even directly, on the condition they are integrated within a larger production or end-use project. | The Fund may amount to € 20 billion, depending on the carbon price. The Innovation Fund supports up to 60 % of relevant costs of projects. | The revenues come from the auctioning of 450 million EU Emissions Trading System allowances from 2020 to 2030, as well as remaining unspent funds coming from NER300 programme. The Innovation Fund grant is not state aid. To cover their remaining costs of their projects, applicants can combine the Innovation Fund grant with other public subsidies. | The fund is open to large-scale projects with a CAPEX above €7.5 million, as well as to small-scale projects with CAPEX under €7.5 million. The projects need to be sufficiently mature in terms of planning, business model as well as financial structure. | Project promoters can apply by submitting their projects when there is an open call for proposals. Projects can apply via the EU Funding and Tenders portal. There will be regular calls for proposals in the lifetime of the Innovation Fund until 2030. | Additional support via blending is also possible, with €100 million currently assigned from the Innovation Fund to InvestEU to enable support in the form of financial instruments (i.e., debt or equity-type debt) via the Green Transition Product. |
| InvestEU | Investments in clean hydrogen are eligible as part of the main policy priority under the InvestEU fund, in particular under the sustainable infrastructure window. | Investments in infrastructure supporting the production or use of hydrogen are considered as critical infrastructure under the InvestEU fund. | Expected to mobilise >€ 372 billion public and private investment through an EU budget guarantee of € 26.2 billion that backs the investment of financial partners (EIB Group) and others. | The funds are allocated under the indirect management scheme through EIB Group (75 % of the guarantee) and other implementing partners. The InvestEU fund may provide funding in the form of grants and loans. | InvestEU is managed indirectly-the Commission will negotiate mandates with financial partners to deploy the EU guarantee available. EIB Group is main financial partner and is expected to deliver on 75 % of the EU guarantee. The remaining 25 % of available budget will be shared between other implementing partners once selected by EC. | EC launches a call for expression of interest. The quality and impact of the application will be assessed on the basis of the information provided in the application, given InvestEU fund is partly financed from NextGenerationEU resources | n/a |

| Name | Objectives | What type of hydrogen related actions can be funded | Funds available (in total, not exclusively for $H_2$) | Financing details | Funding process | How to apply and when | Stated synergies with other funds/finances? |
|---|---|---|---|---|---|---|---|
| Modern-is-ation Fund | Dedicated funding programme to support 10 lower-income EU countries to modernise their energy systems and improve energy efficiency: Bulgaria, Croatia, Czechia, Estonia, Hungary, Latvia, Lithuania, Poland, Romania and Slovakia. | Could be funded via MF as priority investments: Natural gas infrastructure projects to facilitate the use of low carbon/renewable hydrogen in existing gas network. Gaseous fossil fuels are not excluded, providing that a significant GHG reduction can be achieved. | At a price of allowances at €40/t$CO_2$, total revenues of MF could amount to >€ 25 billion, with Romania and Czechia the biggest beneficiaries, followed by Poland. | MF not part of the EU budget nor the NextGenerationEU. Funded from revenues from auctioning of 2 % of the total allowances for 2021 – 30 under the EU Emissions Trading System (EU ETS) | The fund can cover up to 70 % of the relevant costs of non-priority investments, as long as the remaining costs are financed by private legal entities. It leaves the beneficiary EU countries the freedom to decide on the form of support: they can use grants, premium, guarantee instruments, loans or capital injection. | Investments are submitted by the beneficiary EU countries, who are responsible for the implementation of the Fund. MF operates under the responsibility of the beneficiary EU countries, who will work in close cooperation with the EIB, the Investment Committee set up for the fund and the European Commission. | Co-financing from private and public entities is possible, as long as State aid rules are respected and the same costs are not already funded by another Union or national instrument (no double funding). |
| Recovery and Resilience Facility | Aims to mitigate the economic and social impact of the COVID-19 crisis and make European economies and societies more sustainable, resilient and better prepared for the challenges and opportunities of the green and digital transitions. | Covers the whole value chain of renewable and low carbon hydrogen, including pilot projects for the transmission and distribution of renewable hydrogen. | The RRF will provide up to € 337.97 billion in grants and € 385.85 billion in loans. | The RRF is implemented by the EC through direct management. Funding is disbursed in the form of non-repayable financial supports and loans. Each EU country defines the specific components and conditions, in alignment with the requirements of the regulation. Through the Facility, the Commission raises funds by borrowing on the capital markets (issuing bonds on behalf of the EU). | RRF is a performance-based instrument. Pending the achievement of milestones and targets included in the instalment period, the Commission will make a payment to the EU country. Part of the payment will feed the hydrogen projects which are sequenced in different phases, e. g. award of contract/start of the project, intermediary objectives, completion of the project. | EU countries submitted their national reform programmes and their recovery and resilience plans in a single integrated document. Based on EC assessment, EC proposes a Council implementing decision to the Council. | n/a |
| IPCEI Hydrogen | The IPCEI Hydrogen programme was launched in 2020 and is aimed at innovation as well as demonstration and first industrial scale deployment of hydrogen technology. | The projects take place in the complete value chain of hydrogen: production, import, transportation as well as end use. Four clusters of projects – or "waves" for equipment for hydrogen production, fuel cells, storage, transportation or distribution (Wave 1 / Hy2Tech), industrial end uses (Wave 2 / Hy2Use), infrastructure (Wave 3 / Hy2Infra), and mobility end uses (Wave 4 / Hy2Move). Details on the third wave – Hy2Infra – is outlined below. | Wave 1 (Hy2Tech) received eligible aid up to € 5.4 billion, Wave 2 (Hy2Use) eligible aid up to € 5.2 Bn, Wave 3 (Hy2Infra) eligible aid up to € 6.9 billion. Wave 4 (Hy2Move) eligible aid up to € 1.4 Bn | To qualify as IPCEI, a project should involve/require cross-border collaboration with other projects, consist of RDI or First Industrial Scale Deployment that both entail high level of risk | Via the member States. A project must be of common European interest, have a significant impact on competitiveness, sustainable growth, address social challenges and create value across EU, and co-funded by the beneficiaries, | Following an expression of interest procedure by project promoters at national level, the involved Member States may include a 'match making' process at national levels and between MSs, followed by evaluation and notification to EC | n/a |
| IPCEI Hy2Infra | Boost the supply of renewable hydrogen, to meet the EU's decarbonisation objectives (as set out in the European Green Deal and the REPowerEU Plan). | The deployment of new and repurposed hydrogen transmission and distribution pipelines of approximately 2,700 km; the construction of handling terminals and related port infrastructure for liquid organic hydrogen carriers ('LOHC') to handle 6,000 tonnes of hydrogen a year. The IPCEI will involve 33 projects by 32 companies, including five SMEs. The participating companies will closely cooperate with each other through numerous collaborations, as well as with external partners, such as transmission system operators, potential offtakers, universities, research organisations, and equipment suppliers across Europe, including SMEs. | Up to € 6.9 billion by Member States in public funding, expected to release € 5.4 billion in private investments. | More information on the amount of aid to individual participants will be available in the published version of the EC's decision, once the EC has agreed with Member States and third parties a redacted version that will remove all confidential business secrets. | National State Aids | | Several Member States (France, Germany, Poland & Portugal) included their participation in the IPCEI Hy2Infra in their Recovery and Resilience Plans and thus can partially fund some of their projects through the Recovery and Resilience Facility. |

Table 2: Main EU financial programs eligible for hydrogen infrastructure projects

Financial support in the form of EU loans, guarantees, grants and subsidies can significantly assist hydrogen project promoters to minimise risk and provide a certain recognition status to their project, offering an alternative mechanism for project funding particularly in an emerging, unregulated and therefore financially risky hydrogen market.

The examples of various types of financial support summarised above highlight the assistance now available, applying differing project criteria and at differing stages of the project maturity. For example, InvestEU, CEF-E, and the Modernisation Fund offer guarantees for mature technologies whereas Horizon Europe grants are a better fit for the early project stage (R&D). Member States availing of the ERDF can determine at which stage of the project, from early to late stages, receives the financial support.

The table also shows some of the potential issues to availing of these financial supports. Eligibility rules and application processes widely differ across the programmes, and in some cases (e. g., CEF-E) application for funding requires that the project first receives a status of Project of Common Interest (PCI) or Project of Mutual Interest (PMI). Of course, as each of the programmes have been established to address specific project types and needs, it is therefore not practical to have one sole streamlined approach to access any EU funding. However, it may greatly assist project promoters to centralise the information online (a 'one-stop-shop'), and provide points of contact to aid project promoters to enable to firstly identify the correct programme for their project, followed by guidance at early stages of application for financial support. Furthermore, clearer information on the possibility to 'blend' or combine different types of EU programmes, as well as how to best merge private and public funds, would be beneficial. In addition, ideally a central portal (developing the current compass – see above) should also be established at EU level provided updated information and contacts for national State Aid schemes that have been cleared under EU State Aid rules.

By providing fully transparent and easily accessible information for eligibility and application processes, this may then increase the more efficient uptake of public support programmes across the EU, especially for smaller projects whose promoters wish to avoid long and burdensome administration processes.

## 5.3.2 AMORTISATION ACCOUNT

Chapter 4.1. explained why it is not practical to undersize infrastructure capacity, so infrastructure providers will not build networks below a certain minimum size (which means CAPEX will be rather higher than lower). But initially, there will only be few shippers and pipeline capacities and all other infrastructure will be far from fully utilised, which is detrimental to bankability as outlined in chapter 4.3.

There are basically two options on how to deal with this situation. Either the Hydrogen Transport Network Operators (HTNOs) charge the shipper the costs they need to charge to fully bear their own costs, which is how it would work if the current gas market regulation were applied to the hydrogen market. The problem with this approach is that if an HTNO has, for example, three shippers that book only 15 % of the network's capacity, the HTNO will have to charge these three shippers 100 % of the network's costs. No shipper will agree to this – in fact, there would be a strong incentive for industry players to avoid becoming first-movers as they would benefit from waiting for the payment for the new infrastructure to be made by another party which they can use at much lower costs in the future. As a result, the European hydrogen network would not be developed due to this lack of commitment, following prohibitive infrastructure tariffs.

Alternatively, the HTNO need to bear the shortfall in revenue itself, rely on a quick and steep increase in demand and that it might be allowed to charge the costs in the next regulatory period (and find shippers willing to pay tariffs that reflect these costs). This means the HTNOs would take the entire market risk, contrary to their existing business model. Both options will not work in practice.

The EU Hydrogen and Decarbonised Gas Market Package[44] in its current form explicitly allows for inter-temporal cost allocations (ITCA). This means member states have the right to implement measures that lead to future customers contributing to the hydrogen network. Several countries are working to implement such schemes with Germany being one of the front-runners. German TSOs and the government are currently negotiating a so-called amortisation account (AA) with the aim to increase the bankability of hydrogen infrastructure financings. The idea behind the AA is that it acts as a buffer during the period when there is not yet sufficient demand for hydrogen infrastructure, i. e., when hydrogen is not yet a mature market. Figure 5 illustrates the structure and cash flows during market ramp-up:

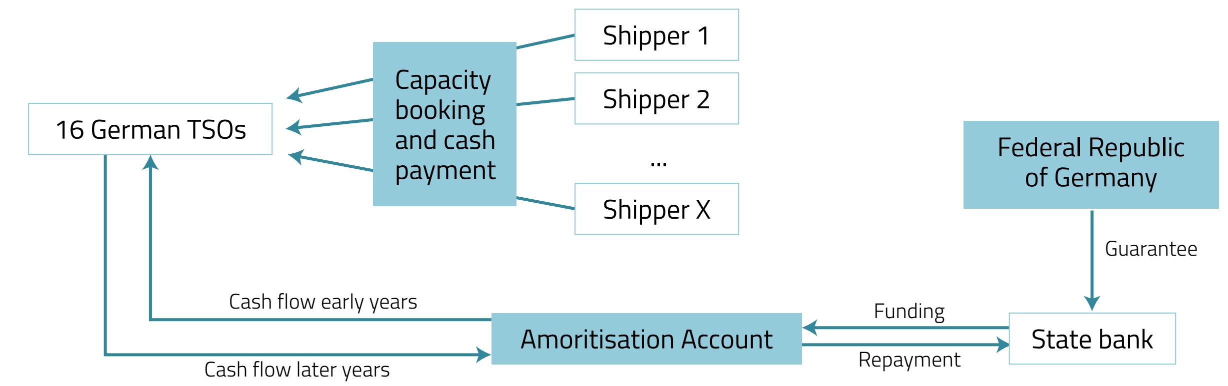



Figure 5: Concept of an amortisation account

From an economic perspective, the concept of the AA allows to bridge the time until the hydrogen economy has evolved and there is enough demand for transportation services. Whatever the shortfall in capacity bookings, the AA will act as "shipper of last resort" and provide cash to the TSOs, virtually "booking" the unused capacity. Funded by the state or a state-owned financing vehicle, funds will flow out of the AA to the TSOs during the market ramp-up[45] on a regular basis. The government issues a guarantee to the bank / the financing vehicle as the commercial rationale behind the funding is not yet there. Banks will have the sovereign rating as risk for the uncontracted cashflows of the network. The payment balance of the AA will therefore be negative and inflate over the years. Eventually, once hydrogen demand (and, hence, capacity bookings from private companies) has reached a certain level and sufficient hydrogen supply is available, the amortisation account will cease to pay cash to the TSOs, which in turn will be allowed to charge slightly more than what their MRA would allow. This extra cash will then be earmarked and used to gradually level the payment balance of the AA (i. e., repay the money which was injected over time into the AA by the state).

44 Hydrogen and Decarbonised Gas Market Package , not yet published in Official Journal of EU as of 10 July 2024

45 Payments to the TSOs will actually have to start already during construction, as RAB increases as soon as construction starts.



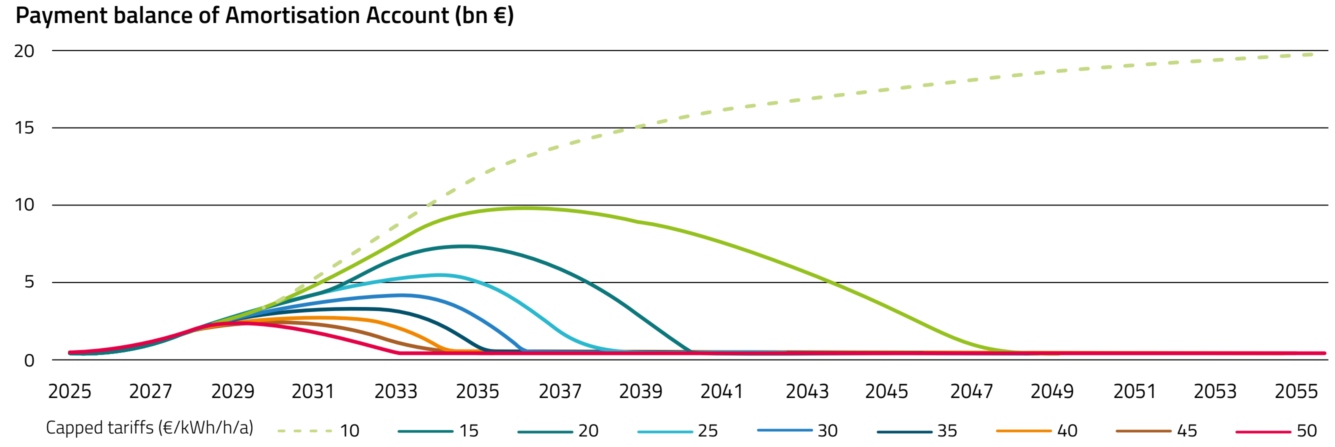



Figure 6: Development of the AA's payment balance in the base case scenario, Source: Fraunhofer, consentec, ConGas, 2024

The maximum amount standing to the credit of the German AA and the timing of its repayment depend on several variables. Figure 6 shows the results in the base case scenario. With a tariff of 15 €/kWh/h/a, the German AA is fully repaid by 2048.

Naturally, different scenarios lead to very different amounts being drawn, different tariffs to be set and different timing to full repayment of the AA, if at all.[46] It should be noted that these results are for the German market and may differ in other countries.

The concept of the AA has been agreed between the German TSOs (as they will also be the HTNOs) and the government. In case the hydrogen economy does not emerge as planned and the government eventually decides to abandon the concept of the AA, TSOs will have to bear up to 24 % of the amount that stands to the credit of the AA at that point in time, which was a highly debated issue. The AA is only eligible for pipeline networks.

Naturally, the concept had to be notified with the EU Commission as it constitutes a state aid.

The advantage of the AA is that it provides security on cashflows, therewith significantly enhancing the bankability of a hydrogen project. With this security on cashflows, banks will ultimately be able to assess these projects and take a lending decision. Shareholders have a high degree of certainty in their investments and will be in a position to take FID. This leads to the physical creation of a hydrogen transportation network in the relevant Member State. It also ensures that not only the first users of the hydrogen infrastructure contribute to its financing and pay their share, but also companies that move less quickly and come into the hydrogen market much later. It can be seen as an evolvement of the regulatory account mentioned in chapter 4.1. with the (rather important) difference that the state is ultimately guaranteeing that the credited amount will be collectable.

## 5.3.3 CLAWBACK AND FLP MECHANISMS

Subsidies and grants are certainly powerful tools for policymakers and governments, but also pose a burden on the respective budgets. Furthermore, at the time the decision is taken, it is unclear if the budgeted subsidies suffice. E. g., The Netherlands have taken the decision to support the hydrogen transportation network ramp-up with EUR 750 m of direct subsidies that may be used to offset losses incurred by the TSO. If the demand is not high enough by then, it is likely that additional support needs to be provided.

Another option how to establish an ITCA scheme would be the introduction of a clawback on subsidies and grant money. This concept is not unknown for infrastructure subsidies, for example in the Gigabit Infrastructure Subsidy Scheme as implemented in the UK[47].

Grants and subsidies would be provided to investments in hydrogen infrastructure which are typically non-repayable. This contributes to financing of these investments and has a direct effect: in the case of a pipeline network, the infrastructure owner and operator would not have invested the full CAPEX itself, so the RAB of this investment is decreased by the amount of subsidies from public sources. In accordance with the envisaged current tariffication regimes for hydrogen networks, the tariffs would reflect this reduced cost basis and be lower than they would normally be had the investment been financed fully with private capital.

It would be possible to define certain milestones by which the success of a hydrogen network is determined, the most striking being the utilisation ratio. A higher utilisation rate than expected could trigger a repayment obligation for the

46 See Fraunhofer, consentec, ConGas for more details and sensitivity calculations, starting from page 22.

47 Gigabit Infrastructure Subsidy Scheme

network owner of a part of the subsidies. This is facilitated by way of increased tariffs[48], which means that public subsidies (i. e. taxpayer money) would eventually be repaid by those wholesale consumers (and, indirectly, end users) which are using the network. With a certain delay, the 'user pays' principle would be observed in this approach with public money serving as a bridge financing.

Similar to the clawback mechanism above, another way to introduce an intertemporal cost mechanism is a so-called first-loss piece (FLP). Just like a clawback, an FLP could help to recover at least a part of the money provided and apply the 'user pays' principle in hydrogen infrastructure projects. This concept is common in mezzanine financings where the mezzanine tranche bears higher risk as it ranks subordinated to other forms of debt (hence the name 'first-loss piece'). In return, it is entitled to receive higher margins than senior debt. The difference to the subsidy clawback is that subsidies constitute grants and normally do not include the obligation for the recipient to repay those whilst FLPs constitute (junior) debt with a binding legal obligation for it to be repaid.

If a member state via public banks or EU institutions like the EIB were granting first-loss pieces to projects, depending on the commercial success of this projects they could potentially be entitled to be partly or fully repaid. At the same time, infrastructure developers would be free in their entrepreneurial activities as first-loss pieces or mezzanine tranches are not equity. The commercial effect would be the same than with subsidies (i. e. money is provided that helps to fund the investment), but unlike with subsidies it would be the infrastructure users in several years who contribute financially to the infrastructure instead of today's taxpayers as is the case for subsidies.

Revision or clarification of the application of EU State Aid rules may be required to allow member states to implement mechanisms like the above. Furthermore, the amounts contributed would need to be sufficiently high so that investment projects are fully financed. Nonetheless, these approaches could complement other sources of financing very well and might merit a closer investigation, particularly in combination with other support schemes as mentioned above.

### 5.3.4 CREDIT INSURANCE

Credit insurance is a frequently used instrument by commercial banks when funding projects. It basically swaps the default risk of the borrower with the credit insurer's, making the financing more attractive from a risk perspective and providing significant capital relief for a bank. There are guarantee schemes from States and from private insurance companies. The latter have similar requirements for investment projects than banks. We focus on state-backed risk insurers in this sub-chapter.

The most well-known credit insurance mechanism are the credit guarantees issued by state-backed export credit agencies (ECAs). Those guarantees were established decades ago to promote the respective country's export industry. The classic ECA credit cover schemes are applicable to export financings only, but meanwhile many ECAs have launched schemes that target imports or domestic projects as well. They typically support projects that are of national interest and / or strategic importance and often focus on climate change or, more generally, environmental protection. Table 3 provides an (incomplete) overview of some of the schemes that are in place.

| Country | Insurer | Scheme | Policy | Credit Cover | Tenor |
|---|---|---|---|---|---|
| Italy | SACE | Push Facility | Raw material sourcing for Italian companies | Up to 80 % | Medium to long-term |
| Spain | CESCE | Strategic Investment Financing | Projects of strategic importance and fighting climate change | 80 % | Depending on project |
| Germany | Hermes | UFK | Raw material sourcing for German companies | 80 % | Medium to long-term |
| France | Bpi France | Garantie des Projets Stratégiques | Projects of strategic importance to the French economy incl. raw material supply | 80 % | Medium to long-term |
| Belgium | Credendo | Green Package | Mainly export, but also eligible for domestic projects if reducing GHG emissions | 80 % | Up to 10 years |
| The Netherlands | Atradius | Green Cover | For investments in green technologies or green capital goods in the Netherlands | Up to 80 % | Medium to long-term |
| Finland | Finnvera | Environmental Guarantee | Domestic projects with significant environmental impacts | Up to 80 % | Up to 10 years |

Table 3: Selected ECA cover products potentially eligible for hydrogen infrastructure projects

48 Technically, RAB would be increased by the volume of subsidies that have to be repaid.



If and to what extent investment projects in the respective ECA's country will benefit from cover is always a case-by-case decision. It depends on the details of the project, the evolvement of guarantee policies and many other factors whether the ECA grants cover for a project.

Notwithstanding this, ECAs have the potential to be or to develop to be a key risk mitigant, making commercial funding in the developing hydrogen market less risky and attracting financing for infrastructure projects.

## 5.4 SUSTAINABILITY ASPECTS OF FINANCING[49]

An important aspect of any financing is how it complies with the respective investors' sustainability targets, which in turn are derived largely from EU and national sustainability goals. All relevant banks and institutional investors publish sustainability reports that provide insights into the business activities of a bank or an institutional investor. They report what share of their activities is dedicated to sustainable projects, how the due diligence process the institution undertakes considers ESG risks and how the governance in the respective institution works with respect to ESG aspects, among other things. Furthermore, the vast majority of the financiers have also issued sustainability guidelines which set perimeters for their financing activities. These guidelines stipulate requirements for the investor itself but also the company it owns or finances. For example, this comprises exclusion lists (mainly relating to certain industries that are fossil-heavy or operate in specific sectors) as well as disclosure and measurement of data like:

— Scope 1, 2 and 3 emissions
— Accidents and lost time injuries
— Community engagement
— Diversity and gender equality
— Compliance and anti-bribery statement
— Leakages and spills
— Compliance with environmental laws
— Progress of measures to be undertaken

This approach results in transparency and comparability within the broader group of financiers. It exerts pressure on the financiers as many shareholders want them to invest and operate sustainably to avoid negative publicity and helps to derive a ranking of a financier within its peer group. Another important development is the obligation for banks to report their green asset ratio (GAR) from 2024 onwards. Banks must classify the individual loans in their portfolio in accordance with the EU taxonomy rules and divide the amount of sustainable loans by the overall amount of the loan portfolio. While there is an ongoing debate about the calculation method and the reporting requirements[50], it is possible that capital market participants and retail customers will use the GAR going forward to compare banks and capital market participants will c.p. prefer those with a higher green asset ratio. This may affect a bank's refinancing costs, therefore incentivizing it to invest more in green assets.

The above exemplifies the significance for investors to invest in sustainable projects. In addition to this, hydrogen infrastructure is an enabler for both the decarbonization of hard to abate industrial sectors and the energy transition – without the respective infrastructure in operation, supply and demand cannot be connected and the energy transition for the hard-to-abate sectors will not take place. Therefore, it is important that investments in clean hydrogen infrastructure can be classified as sustainable in accordance with the EU Taxonomy to attract private investments.

Currently, the Taxonomy Navigator[51] lists "transmission and distribution networks for renewable and low-carbon gases" as an eligible activity and does not discriminate between repurposed or new-built pipelines. The Roundtable believes that the Ten Year Network Development Plan (TYNDP) and the respective national development planning exercises are powerful tools to ensure that the hydrogen infrastructure is being built only where it contributes to reducing GHG emissions and advocates for the plannings to coordinate with the TYNDP of the electricity system.

49 In the Transmission and Distribution Roundtable and in the European Clean Hydrogen Alliance exist diverging views on the topic of low carbon hydrogen, please see the disclaimer: "Joining the ECH2A, NGOs agree to engage and contribute to the deployment of renewable hydrogen in terms of supply, demand and distribution as we promote the rapid phase-out of the use and production of all fossil fuels in order to reach the objectives of the Paris Agreement. Thus, we do not consider fossil fuel-based hydrogen as a short or long-term solution. We see our role in contributing to targeting the use of renewable hydrogen specifically to those sectors and industrial processes which are hard to decarbonise (steel, cement and basic chemicals, aviation, shipping and heavy good vehicles)."

50 BloombergNEF, 2024, European Banks Are Only 3 % Green, Faulted New Metric shows (subscription needed)

51 EU Taxonomy Navigator


# 6 SUGGESTIONS FOR POLICY-MAKERS AND REGULATORS

This Learnbook is designed to illustrate options on how to potentially finance hydrogen infrastructure in the European Union. To this end, the last chapter suggests approaches that are being developed at national level within the EU and in third countries that might be considered at European level to further increase the financial viability of European hydrogen infrastructure projects and eases financiers' decisions.

Some of the recommendations target issues that are within the scope of the policymakers in the EU whilst, depending on the ambition of the EU, some may need to be addressed by the NRAs of the individual member states.

### REGULATION

— Establishing a clear, stable and appropriate regulation is key for the EU-wide hydrogen industry to develop and for transmission and distribution companies to invest.

— Once EU regulation has been agreed and established, it needs to be implemented into national law quickly by the Member States.

— The allowed return on equity should reflect the risk involved with investing in hydrogen infrastructure. Given the early stage of the industry and the high degree of uncertainty about technology, market development, industry standards, and the like it seems adequate to allow for a significantly higher return on equity than in developed markets such as electricity and natural gas.

### PUBLIC FUNDING AND RISK MITIGATION

— Grants and subsidies should be provided to companies already in the planning phase to partly cover costs like feasibility studies and network planning. These studies also help to reduce risks providing a better cost basis for future funding decisions.

— It has become clear that risk mitigation from the EU and its Member States will be required to help ramping up the hydrogen economy and have investors and financiers take investment decisions. Whilst the EU and many member states are working on mechanisms that help to finance hydrogen infrastructure projects either by way of direct cash contribution or by providing risk mitigation for investors, those mainly relate to transmission and distribution via pipeline grids. Given the EU's expected necessity to import clean hydrogen from third countries, it would be recommendable to include $H_2$ dedicated import terminals into these funding and / or risk mitigation measures as they are equally affected by many issues described above and form an indispensable part of the broader hydrogen transportation infrastructure.

— The financial support should be technology agnostic. It is not yet clear which will be the most widely adopted mean to transport hydrogen, in fact it is likely that not only one specific method of transportation will be used but several ones.

— The Connecting Europe Facility is a well-received program that enables pan-European energy projects becoming a reality. Having said that, the overall budget for the CEF is limited and does not reflect the investment needs that the energy transition causes. The Roundtable therefore recommends increasing the CEF budget in the next Multiannual Financial Framework significantly. This is also recommended in the recently published report from former Italian Prime Minister Enrico Letta "Much More Than a Market".

— The existing financial support is manifold and helps project promoters to obtain financing for their investments. However, it is not always clear if and how schemes can be combined and to what extent projects may benefit, if at all, from grants and EU funding during different stages in their lifecycle. The RT therefore suggests making sure that schemes are combinable and that projects may benefit from various programs throughout their lifecycle as long as a maximum threshold of public funding is not exceeded.

— Generally, nascent markets need comprehensive, certain and clear incentive schemes or other public funding instruments such as grants, promotional financing or guarantees providing the necessary financial support to projects, in order to incentivize investments by generating steadier cash flows and thus improve bankability and bridge the lack of commercial viability in the medium to long term.

### VALUE CHAINS

It is important to ensure that projects which receive public funding support are contributing to create value chains. Projects should not be seen separately but in the broader context and pan-European environment they are designed to operate in, in order to make sure that public support helps to create European ecosystems and value chains instead of enabling fragmented, island solutions. In the absence of coordinated European funding, some Member States are more advanced than others in their efforts to adjusting to a European clean hydrogen economy, so it should be safeguarded that infrastructure is supported where it has the largest impact and where it contributes the most to a successful European ramp-up even if this results in a temporary imbalance of the phasing of support across the Member States.

### HYDROGEN CORRIDORS

The identified hydrogen corridors all stretch over several Member States with a specific corridor being implemented only so fast as the slowest Member State. To avoid these corridors becoming political footballs and being delayed, a European mechanism could be introduced that allows the European Commission to accelerate the respective planning decision in the affected Member State. This would contribute to the European energy transition taking place in an efficient and timely manner and in accordance with the aims and timeline of the RePowerEU Plan.

### SUSTAINABILITY

It is important to stipulate clear EU rules under which circumstances hydrogen infrastructure is considered a sustainable / green asset. Hydrogen infrastructure operators, especially TSOs and DSOs, will be required by regulation to provide non-discriminatory access to their assets. TSOs and DSOs cannot be affected by the colour of the molecule that is being shipped through their pipelines.

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# ABBREVIATIONS AND ACRONYMS

**AA** – Amortization Account
**ACER** – Agency for the Cooperation of Energy Regulators
**ARA** – Amsterdam-Rotterdam-Antwerp
**CAM** – Capacity Allocation Mechanisms
**CAM NC** – Capacity Allocation Mechanisms Network Code
**CAPEX** – Capital Expenditures
**CBCA** – mean Cross-Border Cost Allocation
**CCO** – Cost of Construct and Operate
**CEF** – Connecting Europe Facility
**CEF-E** – Connecting Europe Facility for Energy
**CF** – Cost Factor
**CMP** – Congestion Management Procedures
**DSO** – Distribution System Operator
**EC** – European Commission
**ECA** – Export Credit Agency
**ECH2A** – European Clean Hydrogen Alliance
**EEA** – European Economic Area
**EIB** – European Investment Bank
**EIF** – Entry Into Force
**ENNOH** – European Network of Network Operators for Hydrogen
**ERDF** – European Regional Development Fund
**ESG** – Environmental Social Factors
**ETS** – Emission Trading System
**FID** – Final Investment Decision
**FLP** – First-Loss Piece
**FSRU** – Floating Storage Regasification Unit
**GAR** – Green Asset Ratio
**GCC** – Golf Cooperation Council
**GHG** – Green House Gas
**GO** – Guaranty of Origin
**HDNO** – Hydrogen Distribution Network Operator
**HTAR NC** – HTNO Tariff Network Code
**HTNO** – Hydrogen Transport Network Operator
**IEA** – International Energy Agency
**IHC** – Inter-HTNO Compensation
**INF** – Inflation Factor
**IP** – Interconnecting Point
**IPCEI** – Important Projects of Common European Interest
**ITCA** – Inter-Temporal Cost Allocation
**LC** – Low Carbon
**LNG** – Liquid Natural Gas
**LOHC** – Liquid Organic Hydrogen Carrier
**MF** – Modernization Fund
**MRA** – Maximum Revenue Allowance
**NC** – Network Code
**NRA** – National Regulatory Authority
**nTPA** – negotiated Third-Party Access
**OEM** – Original Equipment Manufacturer
**PCI** – Project of Common Interest
**PMI** – Project of Mutual Interest
**RA** – Regulatory Account
**RAB** – Regulated Asset Base
**RES** – Renewable Energy Sources
**RoE** – Return on Equity
**RRF** – Recovery and Resilience Facility
**RT** – Roundtable
**rTPA** – regulated Third-Party Access
**SME** – Small and Medium Enterprises
**SPV** – Special Purpose Vehicle
**TAR NC** – Tariff Network Code
**TEN-E** – Trans-European Networks for Energy
**TSO** – Transmission System Operator
**TYNDP** – Ten-Year network Development Plan.

# IMPRINT


## PUBLISHER

European Clean Hydrogen Alliance – Roundtable for Hydrogen Transmission and Distribution

## SUPPORTED

by the European Commission
Directorate-General for Internal Market, Industry, Entrepreneurship and SMEs



## AUTHORS AND EDITORS

European Clean Hydrogen Alliance Transmission and Distribution Roundtable

Members of the Task Force on Financing of Hydrogen Infrastructure

Lead Author: Andreas Löffler

Coordination and input by: Carmel Carey
Laurent Percebois



## DESIGN

DreiDreizehn GmbH, Berlin
www.313.de

## PICTURES

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iStock.com/Scharfsinn86,
picture editing by DreiDreizehn GmbH (page 11)
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European Commission

# European Clean Hydrogen Alliance

Kick-starting the EU Hydrogen Industry
to achieve the EU climate goals