ENNOH
October 2025
Version for public consultation

Preparatory groundwork in the areas of Future market design

ENNOH Position Paper

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1. Purpose of this paper

In this paper, ENNOH outlines its initial considerations in the areas of the future network codes (Network Codes) tailored to the emerging hydrogen market within the European Union (EU). As the EU transitions towards a sustainable and low-carbon energy system, hydrogen is poised to play a pivotal role in achieving these goals. The development of robust Network Codes is essential to ensure the safe, efficient, and reliable integration of hydrogen into the existing energy infrastructure.

The paper intends to give an overview of the basic considerations that in ENNOH view are relevant for the development of future Network Codes, specifically regarding market integration, competition and non-discriminatory network access. It emphasises the importance of harmonising rules on the operation of the infrastructure across Member States to facilitate a cohesive and unified hydrogen market. Additionally, the paper discusses the technical and economic challenges associated with hydrogen integration and proposes solutions to address these issues.

This paper is deemed to represent the result of preparatory groundwork ENNOH is doing in the areas of future Network Codes. For the avoidance of doubt, the considerations outlined in this paper have non-binding character and do not intend to prejudice the process of the Network Codes development as it is specified in the Gas and Hydrogen Regulation (EU) 2024/1789.

This paper is concepted to be a living document reflecting the current assessment of ENNOH and its members regarding the areas of the future Network Codes. This assessment may evolve over time, so that the currently outlined considerations may also develop further on or be substituted with the new ones. ENNOH and its members are aware of the fact that the establishment of the Network Codes as delegated acts is a prerogative of the EU Commission assigned to her in Art. 72 of the EU Gas and Hydrogen Regulation (EU) 2024/1789. Moreover, ENNOH recognizes the profound experience the EU Commission possess in this field considering the number of delegated acts already established and market proved in the natural gas and electricity sectors. Having full respect towards this prerogative and experience, ENNOH would like to prepare the fulfilment of its own task, that being the development of the Network Codes in the specified areas and thus pave the way for achieving its objectives set in the same Regulation. Considering this ENNOH developed the present paper to provide input to the future development of Network Codes.

2. Introduction

Article 59(1) of the EU Gas and Hydrogen Regulation (EU) 2024/1789 (referred to hereafter as "Regulation" in this paper) mandates ENNOH to develop a proposal for a Network Code in pre-defined areas of the hydrogen sector according to the procedure laid out in Article 72 of the Regulation upon request of the European Commission and based on framework guidelines developed by ACER. The thematic areas for which future hydrogen Network Codes may be drafted include the following, as defined in Article 72(1):

- **energy efficiency** regarding hydrogen networks and components, as well as energy efficiency with regard to network planning and investments, enabling the most energy-efficient solution from a system perspective.
- **interoperability rules** for the hydrogen network, including addressing interconnection agreements, units, data exchange, transparency, communication, information provision and cooperation among relevant market participants as well as hydrogen quality, including common specifications at interconnection points and standardisation, cost benefit analyses for removing cross-border flow restrictions due to hydrogen quality differences and reporting on hydrogen quality.
- rules for the system of **financial compensation for cross-border hydrogen infrastructure** referred to in Article 59 of Directive (EU) 2024/1788.
- **capacity-allocation and congestion-management** rules, including rules on cooperation on maintenance procedures and capacity calculation affecting capacity allocation, the standardisation of capacity products and units including bundling, the allocation methodology including auction algorithms, sequence and procedure for existing, incremental, firm and interruptible capacity, capacity booking platforms, oversubscription and buy back schemes, short and long-term use-it-or-lose-it schemes or any other congestion-management scheme that prevents the hoarding of capacity.
- rules regarding **harmonised tariff structures** for hydrogen network access, including for tariffs at interconnection points as referred to in Article 7(8), rules for applying a reference price methodology, the associated consultation and publication requirements including for the allowed or target revenue, as well as the calculation of reserve prices for standard capacity products and allowed revenue.
- rules for determining the **value of transferred assets** and the **dedicated charge**.
- rules for determining the **inter-temporal cost allocation**.
- **balancing rules**, including network-related rules on nomination procedure, rules for imbalance charges and rules for operational balancing between hydrogen network operators' networks, imbalance charges, settlement processes associated with the daily imbalance charge, if applicable and operational balancing between hydrogen network operators' networks.
- **cybersecurity aspects** of cross-border hydrogen flows, including rules on common minimum requirements, planning, monitoring, reporting and crisis management.

In addition, the European Commission may adopt Network Codes in the form of an implementing act in the following area according to Article 72(2) of the Regulation:

- the area of **transparency rules** implementing Article 66, including further details on the content, frequency and form of information provision by hydrogen network operators and implementing point 4 of Annex I, including details on the format and content of the information necessary for network users for effective access to the network, information to be published at relevant points, and details on time schedules.

Guidelines may be adopted by the European Commission in the form of Delegated Acts in the following areas in line with Article 74(3) of the Regulation:

- details of **third-party access services**, including the character, duration and other requirements of those services, in accordance with Articles 6, 7 and 8.
- details of the principles underlying capacity-allocation mechanisms and on the application of congestion-management procedures in the event of contractual congestion, in accordance with Articles 10 and 11.
- details of the **provision of information**, definition of the technical information necessary for network users to obtain effective access to the system and the definition of all relevant points for transparency requirements, including the information to be published at all relevant points and the time schedule for the publication of that information, in accordance with Articles 33 and 34.

The process for drafting Network Codes is initiated by the European Commission, as per Article 72(3) of the Regulation, through the priority list, which identifies the areas in which ENNOH is tasked with submitting a proposal for a Network Code. The first priority list is to be established within one year of the foundation of ENNOH and subsequently every three years. As a subsequent step in the drafting process, ACER is invited to draft binding framework guidelines as a basis for ENNOH, in accordance with Article 72(4). Article 72(15) of the Regulation however also foresees the possibility for ENNOH to develop non-binding guidance in the areas set out in Article 72(1) and Article 72(2) of the Regulation where such guidance does not – or not yet – relate to areas covered by a request addressed to ENNOH by the Commission.

In this paper, **ENNOH developed the initial considerations** that describe the vision for the fundamental, general aspects of the future hydrogen transmission system, which should be addressed in future Network Codes. The aim of any future hydrogen Network Code should be to promote the development of a competitive, liquid, interoperable, transparent, non-discriminatory and well-functioning internal market for the trade and transport of hydrogen across the borders of the Member States. At the same time, Network Codes should foster the creation of a resilient energy system which is characterised by secure and diversified supply sources. The starting point for hydrogen Network Codes should therefore be putting the challenges faced in the hydrogen sector at the centre of the discussion, namely, how to facilitate a fast and sustainable ramp-up of the hydrogen market in Europe. Physical realities and market needs should be the basis for identifying the commercial needs of the hydrogen system. With regards to financing, this primarily implies the question of how to ensure that infrastructure projects are sufficiently financed and de-risked to be realised. Several thematic areas listed in Article 72(1) and (2) of the Regulation, which relate to financing aspects of the hydrogen market, should therefore be assessed and addressed with this specific aim in mind. Past experiences from the gas and electricity sectors may be non-existent or of little relevance in these areas, as the regulatory instruments addressing investment uncertainties in the nascent hydrogen market cannot be directly compared to them.

It should furthermore be noted that hydrogen will likely play an important role in future revisions or additional Network Codes for the electricity sector, due to its role as a provider of flexibility and resilience/adequacy for volatile renewable energy generation. Hydrogen is one of the best options to introduce elasticity in electricity demand for day-ahead electricity markets through the introduction of more demand bids that are not price-acceptance (i.e., not set at the market price cap). This will occur before balancing, with higher volumes benefiting from this positive externality (rather than just as a flexibility provider) due to the marginalist price system in the day-ahead market.

3. The Role of Hydrogen Infrastructure in the Future European Energy System as a Basis for Future Network Codes

3.1 What hydrogen contributes to the future European energy system

Hydrogen is considered as one of the key vectors to achieve the ambition of climate neutrality in the European Union by 2050 to decarbonize our common energy system. The REPowerEU Strategy[1] of 2022 sets out the aim of producing 10 Mio. Tons of renewable hydrogen in the EU and importing another 10 Mio. Tons of renewable hydrogen from outside the EU. The strategy envisions that by 2050, renewable hydrogen will account for approximately 10% of the entire European energy demand, particularly in the industrial and transport sectors. Given that the production potentials for renewable and low-carbon hydrogen differ significantly between the regions of the continent while at the same time especially industrial demand centres are primarily located in densely populated areas in the centre of the continent, transport infrastructure for hydrogen will play a very important role in developing the future market for hydrogen in the EU and so will storage. It will enable the production of hydrogen in areas where production costs are lowest, thereby fostering the development of a cost-efficient and competitive internal market for hydrogen.

The European hydrogen infrastructure will boost the competitiveness of the European industry in multiple ways:

1. **Decarbonisation and implementation of the Green Deal through much-improved energy logistics and lower transport costs:**

   Renewable and low-carbon hydrogen can reduce the overall energy system costs by providing a cost-efficient solution to decarbonise many sectors of the European industry, such as high-heat energy-intensive production processes. Thus, the report of Hydrogen Europe[2] noted that at a European level, two infrastructures (power grid and hydrogen grid) are cheaper than one, specifically, it means that the development of a pan European hydrogen network in a multi-energy model over the 2030-2050

[1] https://commission.europa.eu/topics/energy/repowereu_en
[2] Hydrogen Europe Infrastructure Report "Hydrogen Infrastructure: the recipe for a hydrogen grid plan"

timeframe could save as much as 330 billion EUR compared to a more isolated approach. Hydrogen will facilitate the decarbonisation of industry by replacing existing grey hydrogen used in refining and chemical processes. Additionally, it offers a viable solution for reducing emissions in various sectors where it is economically feasible. The emissions of industry can be significantly reduced with the use of hydrogen.

Low-carbon hydrogen will be of high importance next to renewable hydrogen to meet these existing and future needs. It will likely come from regions far from the points of consumption. The role of transport will therefore be to ensure a safe and reliable connection between production and consumption regions, thereby creating a viable and efficient energy system. Since these consumers need regular supplies, transport infrastructures will also ensure system resilience by connecting multiple points of production to multiple points of consumption.

2. **Support system efficiency:**

Hydrogen can furthermore avoid significant costs in the electricity system linked to congestion management and redispatch actions, plus the increased price convergence in day-ahead markets due to the higher elasticity of electricity demand that electrolysers would introduce. According to the ACER Market Monitoring Report 2024[3], the EU-wide costs for congestion management in the electricity system reached approx. 4 billion Euro in 2023, with redispatch actions increasing by almost 15 % compared to the previous year. This was accompanied by a significant increase in negative prices in day-ahead (subsidised production that, due to congestion, the system needs to pay users to consume out of time and need) and a persistence of still high levels of lack of price convergence in day-ahead (in spite of the progress in CORE, Nordics, flow based and other developments in market coupling). The availability of electrolysers and hydrogen transport infrastructure, especially in areas of high renewable energy supply rates or in areas where the grid is generally congested, will significantly reduce these costs by increasing price convergence and decreasing congestion in day-ahead. Hydrogen will also help by avoiding costly congestion management actions, sometimes by reducing the electricity consumption profile and utilising storage, and sometimes by ramping up further to produce valuable renewable hydrogen that can be used in a more flexible manner at another point in time or for different use cases. Electrolysers and hydrogen offer flexibility.

By scaling up electrolysis, the costs of producing renewable and low-carbon hydrogen may be expected to further reduce significantly over the next few years thanks to technological improvements leading to better efficiency, making renewable and low-carbon hydrogen cheaper and thereby more attractive to the market.[4]

[3] https://acer.europa.eu/monitoring/electricity_market_integration_2024

[4] See Learnbook: Financing Hydrogen Infrastructure, page 17

The role of the transport infrastructure is crucial, since only a reliable infrastructure makes it possible to connect different suppliers, production sites and other market players to each other, thus ensuring the existence of competition in the market.

Additionally, other technologies besides electrolysis can help lower the costs of low-carbon hydrogen. Low-carbon hydrogen produced from methane, combined with Carbon Capture and Usage or Storage (CCUS), can significantly decrease the carbon footprint of the final gas while being produced. These technologies are already quite advanced and enable the production of large quantities of hydrogen within a relatively short timeframe once deployed at scale yet in the EU. Pyrolysis is also seen as promising, as it produces solid carbon.

Low-carbon hydrogen plays an important role in complementing renewable hydrogen, contributing to market growth and reinforcing synergies among different types of hydrogen for the future. The Gas and Hydrogen Package has defined the legal requirements for low-carbon hydrogen to be recognised as such. To support the ramp-up of the hydrogen market, the application of such rules, such as in the context of the Delegated Act specifying a methodology for assessing greenhouse gas emissions savings from low-carbon fuels, should be defined in a pragmatic manner that does not block the development of this vector or the hydrogen market.

3. **Resilient, diversified and secure energy supply for the European Union:**

   As is the case with the European gas network, a European hydrogen network will allow Europe to diversify its energy supply through a global market for energy. Competitive hydrogen supplies can be imported to Europe either directly through pipelines or in the form of e.g. ammonia at port terminals. Huge volumes of price-competitive hydrogen can reach Europe optimising the same natural gas routes and possibly infrastructures (through repurposing), thus strongly contributing to build a carbon-neutral and competitive EU economy.

   A resilient and secure hydrogen system will not only enable imports from third countries but also leverage the European Union own production potential, thus reducing external energy dependence. Hydrogen can be produced domestically at scale in many European regions — particularly those with abundant resources. A combination of both – domestic hydrogen production and imports from multiple regions of the world will make Europe more resilient and less dependent on individual supply sources.

   This internal production capacity significantly enhances Europe’s energy sovereignty and reduces strategic vulnerabilities. A well-connected European hydrogen network will ensure that these regional production hubs can supply demand centers efficiently and in a secure manner.

4. **Providing flexibility to the electricity system:**

   While the ramp-up of renewable energy sources in the electricity sector has led to a significant decrease in CO_2 emissions associated with electricity consumption in Europe, it has also made the market more volatile. The gap between the highest and the lowest electricity prices within a single day has, on average, doubled over the last five years. Solar, wind and hydro energy can reduce energy prices in total, however, they usually also require high subsidies (except for hydro) and a flexible energy system to guarantee market stability.

Batteries and mechanisms such as Demand-Side-Response can only provide such flexibility to a limited extent due to budget and physical limitations. They are best suited for short-term variations in electricity supply and demand. For long-term flexibility needs in periods of weeks, months or entire seasons, such technologies and mechanisms are not suitable, and the storing of energy in the form of molecules becomes the only efficient and sustainable option.

Electrolysers will ramp down automatically in cases of electricity scarcity (to avoid facing high electricity costs) and use stored hydrogen transported by backbones or switch to low-carbon hydrogen production (dependent on gas supply and storage), hence reducing congestion and restoring electricity to the grid by not consuming it. Excess renewable energy that cannot be consumed by the market or exported due to congestion can be converted into renewable hydrogen locally through electrolysis instead of being curtailed. This hydrogen can then be stored in pipelines and storage for future use through re-conversion into electricity or used directly either as fuel in thermal processes, or as a feedstock. The advantage of this is that flexibility occurs automatically due to the inherent business drivers of the hydrogen production process and sector coupling. There is no need to reschedule mobility or heating schedules. Additionally, as mentioned, hydrogen infrastructure for the transport of energy is capable of higher throughput capacities at lower costs, and the same is true for storage, further contributing to flexibility and energy efficiency (both clear positive effects).

Sufficient incentives for hydrogen storage investments should be considered via long-term capacity contracts, as pure price arbitrage is unlikely to incentivise investment at the early market ramp-up phase.

The hydrogen infrastructure system enables the maximisation of renewable electricity production, which is limited by the characteristics of the power grid and market. It therefore needs to be planned and developed in an anticipatory way and in close coordination, not only with gas but also with the electricity system, to identify where connections between the two systems are most beneficial for providing flexibility as efficiently as possible.

To provide flexibility externalities (day-ahead, intra-day) and services to the electricity system, the hydrogen system will need to comply with its system interface requirements. This means that market rules defining access to the hydrogen system must be designed in a way that facilitates the use of the hydrogen system as a flexibility provider. Areas where this becomes obvious are, e.g. balancing provisions, where rules for the hydrogen market need to reflect the role of the molecules system as a (long-term) flexibility provider. Capacity products and mechanisms to allocate such capacities also must be designed in a way to ensure that the hydrogen system can be accessed on short notice, depending on the volatile production in the electricity system. Conversely, rules to facilitate the connection of electrolysers to the electricity grid (HV Demand Connection Network Code) also need to remove any artificial barriers present for these, in comparison to the generic treatment of P2G in relation to Demand Side Response.

Based on the current assumptions of the role of the H2-infrastructure, ENNOH would like to present the following considerations, described in the chapters below:

3.2 Overarching considerations related to hydrogen Network Codes

In ENNOH view the basic considerations in relation to all areas of future market design should be as follows:

1. **The future hydrogen market design should take over positive experience from both the electricity and natural gas sectors**

   There already exists valuable regulatory experience in the natural gas and electricity sectors, including regulation through Network Codes, which could be beneficial for the emerging hydrogen sector. Some fundamental similarities are already provided for in the legislation, such as the future organisation of the hydrogen networks as an entry-exit system (Art. 7 (6) of the Regulation) or the obligation of the hydrogen network operators to offer capacities to network users based on equal contractual conditions (Art. 7 (1) of the Regulation). These similarities make it possible and reasonable to design the hydrogen network rules based on the already well-established system for gas networks. In addition, it is expected that most hydrogen network operators will emerge from existing gas network operators, thus synergies could be realised through joint procedures and systems, including IT that has been developed and tested over the years and can be applied to hydrogen in the future. The new Network Codes may, however, also develop different rules, which could result from the special features of hydrogen, as well as from other considerations, such as a need for integration with the electricity market (sector coupling). Thus, in the upcoming sections, there will be some examples given, where the differences between hydrogen, natural gas and electricity would, in our view, justify a different regulatory treatment of these energy sources in the Network Codes.

   Moreover, it has to be taken into account that the hydrogen market is currently in a ramp-up phase, so that not all regulatory rules typical for a well-established market like those of natural gas or electricity, could yet easily be transposed in the hydrogen sector and this means that the development needs to be paced to the market in order to facilitate it, rather than obstruct it with overregulation.

2. **The future hydrogen market design should take the special characteristics of the ramp-up phase into account**

   Network Codes should, in principle, be developed to regulate market and network access for interconnected systems, as the aim is to harmonise these rules for network users in the entire Union. Isolated networks in individual regions do not necessarily require harmonisation. As the hydrogen system in Europe is expected to be developed from initially separated networks, the question of when to harmonise market rules arises. One regulatory challenge to be addressed is finding a compromise between the specifics of the ramp-up phase and the need to establish market design rules with sufficient clarity and uniformity for market participants.

There is no specific legal definition of the ramp-up phase, which can be explained by its main characteristics, such as clustering or regional limitations within future market areas, substantial investment needs, and financial uncertainties or risks related to market immaturity. Complex rules on market access could be detrimental to the successful development of the market during this phase, as they would add to the already high risk for investors due to market uncertainty and the introduction of new technologies.

Clusters or Hydrogen Valleys are likely one of the characteristics of the ramp-up phase. At the beginning when the hydrogen infrastructure is being built or developed from repurposing of the natural gas pipelines and when such projects are realised by different operators and at different pace, it may be expected that an important part of new hydrogen networks or subnetworks within the respective market areas would initially not always be connected to each other and would represent a number of clusters rather than a united network. A connection between different clusters, which will eventually enable hydrogen transport across regions, will likely be a long-term process. Another characteristic of this early phase is an enormous financial challenge faced by the network operators who are supposed to establish a well-functioning hydrogen network, at the same time not being able to rely on a future network usage. There is a balance at play, whereby there is a need for anticipatory investment in backbones and optimal sizing for the future (as planned via the TYNDP), and a need to keep pace with market development to avoid prolonged underutilization periods and minimise their impacts. Electrification is not a stranger to the very same problem.

The Network Codes we consider a priority at this stage, and for which we propose a set of initial considerations further below in this paper, are the rules on financing and de-risking of the hydrogen infrastructure, as well as the rules on network access. The initial Network Codes should make it financially possible and attractive for the hydrogen operators to create hydrogen infrastructure by improving investment certainty. Furthermore, they should create a consistent framework for access to hydrogen networks from the outset. At the same time, they should facilitate the ramp-up of the hydrogen market itself.

In our view, it is necessary that the first Network Codes should provide for some degree of flexibility in cases where practical market requirements or new challenges arise over time, not necessarily during the current ramp-up phase.[5] In this respect, it is in our view important to note that the specific considerations discussed below in relation to particular areas of future Network Codes reflects the current assessment of an existing market situation and existing challenges. This means that the initial rules to be set in the prioritised Network Codes and fitted for the ramp-up phase would necessarily need to be reviewed or supplemented during market maturing, all while ensuring that the framework relevant for investors remains predictable to avoid financial and regulatory uncertainty. The same concerns apply to the considerations

[5] See also considerations of the German regulator when proposing and consulting the initial rules on hydrogen market design

proposed and discussed in this paper, which should also be subject to regular revision during the transition from the ramp-up phase to the established market.

3. **Cooperation with third countries should play a significant role in the establishment and implementation of the future market design rules**

   When creating market design rules, special consideration should be given to the necessity for the EU hydrogen market to be interconnected with third countries, enabling the establishment of reliable, competitive, and diversified import routes. In this respect, it is important to consider how to address potential issues related to the interconnection points to third countries.

   Pipeline imports of hydrogen from and via neighbouring countries into Europe will only be possible if we have a reliable and well-functioning cross-border infrastructure as well as clear and reasonable rules applicable to the interconnection points to third countries.

   The application of the EU regulations, including Network Codes, is confined to the territory of the EU Member States. The Gas Directive foresees that the operating rules for hydrogen interconnectors with third countries (including the respective border interconnection points) should be enshrined either in an international agreement between the EU and the third country or in an intergovernmental agreement between the Member State and the third country. Apart from the envisaged international agreements, the private grid connection agreements between the hydrogen network operators on both sides of an interconnection point will be indispensable for a smooth operation of a cross-border infrastructure. In this regard, substantial importance should be given from the outset to maintaining alignment with third countries and their respective operators, in order to agree upon the appropriate and acceptable rules for all involved partners (especially regarding interoperability, safety, operational specifications, and other technical norms). This will furthermore ensure early harmonisation of rules and procedures, thereby reducing the need for later harmonisation due to possible divergence between different third countries. Whether there is an appropriate way to integrate the topic of relations with third countries into the future Network Codes remains open at this stage and will need to be determined during the development of the Network Codes.

4. Considerations related to hydrogen Network Codes related to Accessing the Hydrogen Infrastructure

4.1 Balancing rules

ENNOH has identified 3 overall themes to consider in terms of the development of the possible regulation on balancing for hydrogen markets.

1. **A close connection to renewable generation will influence the need for flexibility, timing and operation of the balancing system**

   A significant portion of the renewable hydrogen produced in the EU will come from electrolysis, which relies on power generation, particularly from renewable energy sources. Another part may come from biomass. This means that the hydrogen system will be closely connected to these sources, directly or via the power system, including the volatility in supply and demand. This opens opportunities, e.g. that the hydrogen system can act as a flexibility provider towards the power system, but also includes challenges, in terms of volatile hydrogen production (see also point 3 below), and thereby also a more sensitive and less flexible system.

This also explains the importance of low-carbon hydrogen (nuclear, from methane reforming with CCS, etc.) and of storage facilities and a backbone with line-pack capacity. Thus, the existing synergies with RES variability could influence how to design key elements of the balancing design, e.g.:

- The balancing period during which market players should balance their input and offtake, to reflect the volatility and create value for the power market from hydrogen.
- Tools to incentivise a balanced management of the hydrogen system through its users, including aspects such as imbalance charges or tolerances granted.
- Lead times for nominations for hydrogen should be designed in a way that enables market players to react appropriately to volatile power production, considering the technical and operational constraints and encouraging information exchange on consumption and demand between the hydrogen and electricity markets within the boundaries of REMIT.
- Gate closure times for the energy markets for different time frames (long term, day ahead, intraday and balancing for the part in which they are not continuous) must be coordinated and optimised across carriers.

2. **Balancing regulation needs to embrace both the immature start-up market for hydrogen and the evolution towards a more mature value chain**

There is no integrated hydrogen market as it is today, as the full value chain needs to be developed. This means that the number of market players and liquidity are expected to be limited in the first years of operation. Also, the hydrogen infrastructure will not be fully developed from day 1 but will consist of separated clusters or clusters interconnected with limited capacity as well as likely limited storage capacity, which again may influence the level of flexibility available in the system(s), reason for which the co-development of renewable and low-carbon hydrogen is essential.

Hence, the balancing regulation should accommodate both the immature hydrogen market in the beginning and the development towards a more mature and integrated market, e.g. by:

- Starting out with one balancing system that serves both the initial ramp-up phase and a more mature market, but where exemptions to certain parts of the regulation are allowed within a specific time frame or based on certain objective criteria.
- Allow for non-market-based measures during the ramp-up phase, due to an illiquid market.

- Building up requirements based on the market's maturation.

Overall, various instruments and mechanisms will be required to balance the developing hydrogen system, depending on national and regional circumstances, and under the supervision of the Regulatory Authorities.

3. **The expected nature of hydrogen production and consumption will generate balancing needs that are different from those of methane**

Part of the renewable hydrogen production is expected to fluctuate based on renewable power production/generation. However, this is not all foreseen hydrogen production (since there will also be low-carbon options). Besides, hydrogen consumption is expected to be relatively consistent, as off-takers will initially and mainly be large industrial clients with stable demand, which is expected to vary in high price scenarios.

This also means that the dynamics in the hydrogen market are expected to be different (compared to methane), in terms of the need for short-term flexibility, which also needs to be considered in terms of balancing regulation, e.g.:

- More sizeable short-term volatile fluctuation periods during the day, due to power generation from wind and solar.
- Complementarity to short-term flexibility needs (such as hourly or daily needs).

4.2 Capacity-allocation and congestion-management

When developing rules for marketing, calculating and allocation and congestion management for hydrogen capacities, some differences compared to the existing framework of NC CAM for methane need to be considered, mainly stemming from the early stage of the still-developing hydrogen market. Still, the new Network Codes to be proposed by ENNOH can largely relate to it, as the underlying principle should also be to provide non-discriminatory and regulated third-party access for network users to the transmission networks. The just emerging market field "hydrogen" is considered the most significant variation compared to the long existing methane sector. Hence, there is likely not as much requirement for congestion management (at least not within the ramp-up phase or next 5-10 years).

1. **Standardised capacity products and allocation mechanisms ensure an efficient use of the system and fair access conditions**

Standardised capacity products may comprise yearly, quarterly, monthly and daily products to provide some flexibility to the market. Some interconnectors may also choose to offer weekly products. However, to facilitate the ramp-up of a European hydrogen transmission network, it is necessary that long-term contracts support the stability of the system as well as planning security and hence should be the favoured option initially. Potential booking vacancies might threaten the financing of the hydrogen network. Furthermore, the potential for capacity overruns during the ramp-up of an immature market may necessitate additional flexibility and tolerances.

Furthermore, the product conditions for utilising hydrogen transport capacity must align with the applicable balancing rules (see Chapter 4.1).

Similar considerations apply to the implementation of procedures for capacity allocation. "First come first serve" booking and/or an open subscription window might be good options in the beginning, to be potentially changed to auctions later when capacity levels have stabilised. Generally, the auction process should be appropriate to address the characteristics of the hydrogen market.

Further points for consideration regarding the design and allocation of capacities may include:

- Firm and interruptible capacity products should be implemented whereas interruptible capacity should be marketed after firm capacity.
- As in the NC CAM, hydrogen capacity products should also be bundled at IPs to facilitate cross-border trade.
- The newly designed rules for hydrogen should be applicable to IPs and entry and exit points from and to third countries.

  European booking platform(s) should be implemented. In addition, such a platform would couple the network and infrastructure side with the "H_2 mechanism" foreseen by the EC to stimulate Demand and Supply matching.
- Shipper registration, as well as licensing and proof of creditworthiness, is needed to minimise the risks for HTNOs and to ensure a functioning market.
- A secondary market should also be included.

2. **Congestion management is likely not going to be an issue of concern at least for the foreseeable future**

   As mentioned above, congestion management rules will not be needed during the initial phase, but they might be included as an option for later and for short-term optimisation. One can propose to offer unused booked capacity on an interruptible way.

4.3 Harmonised tariff structures

The aim of this possible new regulation is to provide regulated third-party access for network users to the transmission network under transparent, non-discriminatory and cost reflective tariffs. As a general consideration, tariff models for hydrogen should be simplified compared to the system that has been developed for methane in the past.

1. **Capacity-based tariff systems are to be preferred**

   There is still uncertainty about which transmission points will in future be covered by a European Network Code (such as production/injection points, interconnection points, interface cluster/backbone, interface transmission/distribution, end-users except electricity generators, electricity generators, storage, import points).

   Irrespective of the future scope, ENNOH believes that a capacity-based tariff model (meaning tariffs in €/kW/year) is generally preferred, particularly in the early phases of market development.[6] At the same time, hydrogen transmission network operators should not carry volume risk to encourage capacity build-out. Thus, it should be considered whether volume-based incentives should be implemented on top of the capacity tariff to incentivise efficient capacity rollout. While capacity-based charges should be the primary element of network tariffs, a combination of both volume and capacity-based elements may best suit individual market needs.

Unlike natural gas, hydrogen demand at the ramp-up phase (mainly industrial and flat) may not exhibit very strong seasonal peaks, which (at least for a while) may reduce the relevance of peak-driven capacity signals.

However, capacity-based tariffs still provide essential benefits:

- Revenue predictability in low-utilisation phases
- Investment certainty for hydrogen transmission network operators
- Simplicity in tariff application and billing

In the context of hydrogen network tariff design, the application of short-term multipliers appears necessary to incentivise long-term capacity bookings. These multipliers play a critical role in ensuring cost recovery, providing stable investment signals, and encouraging early market development through long-term commitments. As a further incentive for long-term bookings, holders of long-term capacity may be offered a reshuffling service. This would allow them to offset the monetary value of the newly acquired firm yearly, quarterly, or monthly capacity products against existing yearly or multi-year capacity contracts.

Conversely, the application of seasonal factors may be reconsidered or limited. Given the expectation that hydrogen production and consumption patterns will remain relatively stable throughout the year, seasonal differentiation in tariffs may not reflect actual system usage and could introduce unnecessary complexity.

This approach should be revisited as real demand profiles emerge, particularly in relation to industrial off-takers, storage cycles, and renewable generation patterns.

Depending on the future scope of the Network Code, there may also be justification for discounts on tariffs.

[6] This approach aligns with current regulatory practices in Germany and the Netherlands, and supports a stable framework for hydrogen infrastructure rollout. Both Germany and the Netherlands are opting for capacity-based tariff models (€/kW/year), aligned with the entry-exit system principles already used in natural gas:

Germany (BNetzA) proposes a uniform tariff of 25 €/kWh/h/year for entry into or exit out of the central hydrogen network, applicable to firm annual capacity products. Multipliers for shorter-term products and possible discounts at specific points are also considered.

The Netherlands currently applies a tariff of 42.26 €/kW/year, divided between entry and exit. This value is based on a leveled cost estimate and will be reviewed before 2033. The authorities consider this approach better reflects capital and operational costs and is evaluating future adjustments based on volume, location, and user type.

2. **Potential link with other Network Codes is to be considered**

   Article 72 of the Regulation indicates that there can be an NC on rules for determining the value of transferred assets and the dedicated charge, and another one on rules for determining the inter-temporal cost allocation.

   The network code on the dedicated charge added on gas network tariffs to lower the hydrogen network tariffs (article 5 of regulation 2024/1789) should be mentioned in this NC on the harmonised tariff structures and be consistent between these two NCs.

   The same considerations are relevant for the inter-temporal cost-allocation NC and the way the tariffs are lowered in the first phase and increased later to settle the amortisation account.

5. Considerations related to Hydrogen Network Codes on Financing and De-Risking of Hydrogen Infrastructures

5.1 Value of transferred assets and the dedicated charge

Article 59.1.b of the Regulation prescribes that this Network Code is to be developed jointly between ENNOH and ENTSOG. It is further to be highlighted that the Regulation mandates ACER to draft recommendations both on the determination of the value of assets as well as on the application of a dedicated charge in case of financial transfers.

ENNOH believes that the following considerations should be taken into account:

1. **Higher risks for network operators to be considered in the regulatory handling of transferred assets**

   DNV and Trinomics published a report end of 2022 for ACER on Repurposing, Decommissioning and Reinvestments[7]. This report recommends taking into account for the valuation of transferred assets:

   - **The residual asset value of the individual asset in the natural gas RAB**

   and

   - **The associated repurposing costs to its transfer from a natural gas network towards a hydrogen network** (e.g. cost of technical feasibility of a repurposing, cost for new components/components that must be replaced for H_2 (e.g. valves), cost associated with the separation of assets and organisations, costs related to the actual transfer …)

   Then, one should discuss how to speed up the energy transition, hence repurposing. Furthermore, HTNOs will encounter higher risks because of the development of their network in parallel with the development of the hydrogen market.

[7] https://www.acer.europa.eu/sites/default/files/documents/Media/News/Documents/Future%20Regulation%20of%20Natural%20Gas%20Networks%20-%20Final%20Report%20DNV.pdf

For these two reasons, either:

- A share of the savings due to the use of a cheaper repurposed asset instead of a newly built could be added in the HTNO CAPEX.
- An enhanced rate of return, as decided in Germany, could be applied to HTNO's RAB.

2. **Rules on the dedicated charge need to be further elaborated as the legal basis in the Regulation seems at least partly unfit**

   Articles 5.4. and 5.5 of the Regulation sets out already some features for this funding mechanism of hydrogen networks via a dedicated charge on gas network tariffs of exit points to final customers.

   This dedicated charge should be stable, small (compared to the gas transmission tariffs, it is an add-on) and applied until the hydrogen market reaches maturity.

   The characteristics of the dedicated charge are described in articles 5.4 and 5.5. need detailed discussions to see if the dedicated charge could, effectively, be stable, small and applied as long as needed. For instance, 5.5.c. ("a financial transfer is approved for a limited period in time, and that period is no longer than one third of the remaining depreciation period of the infrastructure concerned") does not seem practical to implement.

5.2 Inter-temporal cost allocation

The mechanism of inter-temporal cost allocation is outlined in Article 5(3) of the Regulation, which stipulates that the recovery of investment costs be spread through network access tariffs over time, ensuring that future users contribute to the initial development costs of the hydrogen network. Inter-temporal cost allocation leads to decreased network tariffs during the early phase of the market ramp-up when the number of network users is still relatively low, thus incentivising the connection of users to the hydrogen system. By lowering the network tariffs below the level that would usually reflect the corresponding costs of the system during the early phase, the demand for transport capacity increases, thus a part of the missing revenues can be balanced out immediately. Any additional lack of revenue for hydrogen transmission system operators would have to be balanced out regularly through a financial mechanism which allows them to recover later in the future e.g. through network tariffs that are then higher than usually reflected through network costs.

ENNOH believes that the following consideration should be taken into account:

1. **Cost recovery guarantees are an indispensable element of any inter-temporal cost allocation mechanism**

   Naturally, accepting a lack of regulated revenues in the early phase of the market ramp-up increases the investment risks for investors in a market that is already characterised by a high degree of uncertainty regarding its future size. The Regulation, therefore, foresees that Member States may put in place measures, such as a state guarantee, to cover the financial risk of hydrogen network operators associated with the initial cost recovery gap arising from the application of inter-temporal cost allocation, provided that such measures comply with Article 107 TFEU. ENNOH considers that such guarantees are indispensable for any inter-temporal cost allocation to be acceptable for network operators, as these regulated companies are not able to cover the increased financial uncertainty. Regulated subjects should not bear any risk related to allowed revenue shortfalls referred to infrastructure utilisation. All risks related to HTNOs revenues shortfalls, including potential project overrun costs, should be fully addressed by the regulatory framework ensuring a full cost recovery of efficient investments.

Such guarantees could be designed in different formats, e.g. in the form of financial guarantees that take effect in case the returns from network services are not sufficient to meet the network operators allowed or target revenue or also in the form of capacity booking guarantees that ensure that a certain share of capacity bookings would be carried out by a political institution in case the booking levels from the market are not sufficient.

Lastly, it is to be noted that the 2025 Copenhagen Infrastructure Forum[8] has mandated ENNOH in cooperation with ENTSOG to further work on possible de-risking options and deliver a report on this topic by the next Forum in 2026. In parallel to any potential work on a future Network Code on the topic of inter-temporal cost allocation, ENNOH will therefore be engaged in a thorough analysis of de-risking mechanisms to address this task.

2. **Coordination of inter-temporal cost allocation mechanisms between Member States can enhance the financial viability of import corridor projects**

A few Member States have already made use of the mechanisms foreseen in the Regulation or are currently working on introducing them. It is, however, obvious that not all Member States are in a position to provide the necessary financial guarantees to their network operators. This could, e.g. be the case for Member States that expect to be primarily transiting hydrogen between production and demand centres in other parts of the Union. It could not be expected from these Member States to guarantee the use of a transit system that primarily benefits other Member States through public funds.

In the context of realising the planned hydrogen import corridors that connect future supply centres with the anticipated demand regions, a consistent application of inter-temporal cost allocation is therefore needed. Corresponding guarantees should either be provided jointly by the involved Member States, reflecting the individual risks associated with the projects, or at the European level.

3. **Long-term view on infrastructure planning is required**

Infrastructure should be planned with a long-term perspective to avoid inefficient developments and ensure cost-effectiveness. In this sense, it’s crucial that the criteria to identify infrastructures to be financed through an inter-temporal cost

[8] https://energy.ec.europa.eu/events/11th-energy-infrastructure-forum-2025-06-02_en

allocation mechanism do not result in a short-term planning approach. Accordingly, the hydrogen network should be sized from the outset, reflecting long-term demand needs for hydrogen, and developed over time on this basis, through a phased approach.

5.3 Financial compensation for cross-border hydrogen infrastructure

The Network Code in question refers to the system of financial compensation to ensure financing for cross-border hydrogen infrastructure in the event that no tariffs are charged for access to hydrogen transmission networks at interconnection points between Member States pursuant to Article 7(8) of the Gas/H_2 Regulation (EU) 2024/1789. The option not to charge tariffs at interconnection points between Member States is foreseen in the Regulation as a derogation from the provisions of Article 17, the application of which is to be decided by the competent regulatory authorities. Article 7(8) further foresees that tariff methodologies shall be consulted and that regulatory authorities may request ACER to provide a factual opinion on the methodology for setting the hydrogen network access tariffs or reserve prices for the entry and exit points at cross-border interconnection points between Member States and that the details of these procedures are to be set out in the Network Code.

ENNOH believes the following considerations should be taken into account when deciding on such a procedure:

1. **Network tariffs should be the primary tool to allocate the costs of the system in a fair and cost-reflective manner**

   According to Article 17, network tariffs should facilitate efficient trade and competition, while also avoiding cross-subsidies between network users and providing incentives for investment and maintaining or creating interoperability for transmission networks. Not applying any network tariffs between Member States does not mean that no costs will be charged; the service could eventually become more expensive due to the inefficiency of price signals (or the lack thereof). No tariffs would unavoidably lead to cross-subsidies as the costs implied by these transport services would have to be borne by other network users at other parts of the system (mainly domestic network users). Especially Member States with systems that primarily serve the purpose of transiting hydrogen between other Member States could be heavily impacted by such a model, as incentives for investments into such infrastructures would be significantly weakened. In case the costs and benefits of hydrogen infrastructure are not aligned with the respective investments on both sides of an interconnection point, several options should be considered to facilitate an appropriate balance, taking into account the interests of the involved parties.

   A further implication of not applying tariffs at IPs is the likely need to establish an EU-wide Inter-Transmission System Operator Compensation (ITC) mechanism. While such a mechanism could serve to redistribute costs among TSOs in the absence of direct cross-border tariff revenues, its implementation would introduce considerable complexity, challenges, and potential inefficiencies. This includes the design of harmonised methodologies for cost allocation, the development of robust data exchange and monitoring frameworks, and the establishment of governance structures to ensure transparency, fairness, and regulatory oversight. Moreover, the administrative burden and difficulty in setting up the ITC undermine the appearance of support expected from tariff exemptions, particularly in systems with significant transit flows. It is important to highlight that cancelling tariffs does not make systems cheaper, and the price signals are lost, or replaced with revenue distribution by some other mechanisms for revenue allocation that may perform worse and are more complicated.

ENNOH therefore believes that cost-reflective network tariffs should, as a default, be charged at all points of the system, including interconnection points between Member States.

2. **The option not to charge tariffs at interconnection points should remain voluntary for Member States and regulatory authorities, and effects from its application within a single Member State should not have any detrimental effects for other Member States**

   Should a Member State decide to make use of the derogation from Article 17 of the Regulation and thus not apply network tariffs at interconnection points to other Member States, it should do so in coordination with its adjacent Member States. Should Regulatory Authorities from adjacent Member States, however, not agree on a joint procedure to apply no such tariffs at both sides of the interconnection points, the application on one side of the border should not have any detrimental effects on other Member States. A loss of regulated revenues from transport services at interconnection points should be balanced with revenues from transport services at other parts of the hydrogen transmission system within this specific Member State.

   Member States making use of the derogation should make sure to highlight the consequences for all users of the transmission system in their public consultation on the tariff methodology. These consequences should be further assessed and evaluated by ACER in their subsequent opinion.

   As a conclusion, ENNOH believes that the Network Code on financial compensations for cross-border infrastructures would be a priority, should Member States decide to make use of the option not to charge tariffs at IPs. Should Member States not decide to make use of the option, the relevance of such a Network Code would be rather low.

6. Initial considerations related to further areas of future Network Codes

6.1 Interoperability rules

Harmonised rules on interoperability at interconnection points between Member States are important to ensure that hydrogen flows across the borders are not hindered or negatively affected by diverging rules or standards. ENNOH will therefore play an important role in ensuring that European hydrogen transmission network operators work together closely on these aspects. ENNOH will ensure that the necessary formats are established within its governance to address interoperability aspects and involve all relevant stakeholders.

Certain aspects of a future Network Code on Interoperability could therefore be prioritised in the future, especially when an upfront harmonisation of procedures can reduce future lengthy alignment processes. Such aspects could include the design of Interconnection Agreements, common sets of units, settlement and information exchange procedures on hydrogen quality, as well as data exchange.

6.2 Energy efficiency

ENNOH considers energy efficiency as very important, especially in the context of planning the interlinked European energy system. By converting surplus renewable energy into hydrogen, the waste of precious resources will be avoided. Hydrogen increases the potential of renewable energies and maximises the use of renewable production assets.

System efficiency, meaning the realisation of an energy system that is constructed and operated optimally as a whole, is considered the fundamental principle of the European energy planning processes. As such, we believe that it is the joint task of ENTSO-E, ENTSOG and ENNOH to work together in their linked TYNDP-procedures under the oversight and scrutiny of ACER and the European Commission.

6.2 Cybersecurity aspects

Cybersecurity threats have increased significantly over the last years for the entire European energy system. ENNOH will work together, especially with ENTSO-E and ENTSOG, on joint procedures to tackle such risks alongside infrastructure operators.

While the Network Code is supposed to cover only cybersecurity aspects, some physical security aspects may also be addressed at the European level. Threats in the form of terrorism and sabotage have increased significantly over the last years, especially targeting offshore energy infrastructure. The European Commission has presented an action plan on strengthening the security and resilience of submarine cables. While the plan focuses primarily on submarine cables, some of its actions could be leveraged or extended to enhance the security of other maritime critical infrastructures, such as pipelines.

6.3 Transparency rules

Ensuring transparency on relevant parameters of the hydrogen transmission system is one of the primary tasks of ENNOH. ENNOH will therefore develop a platform for stakeholders to access data from its members as foreseen in the Regulation. ENNOH will involve all relevant stakeholders in designing the parameters of this platform.

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