Annex – ACER assessment

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1. INTRODUCTION

(1) Hydrogen is expected to play an important role toward the Union's climate objectives and the overarching goal of climate-neutrality by 2050 by enabling the decarbonisation of hard-to-abate sectors. Establishing an integrated hydrogen network across the EU is deemed essential for the cost-effective delivery of renewable hydrogen to end-users. However, building this network is costly, and uncertainty around future hydrogen demand makes early investment decisions particularly challenging.

(2) To support the development of an internal hydrogen market, the EU has introduced Directive (EU) 2024/1788 (the Directive) and Regulation (EU) 2024/1789 (the Regulation). These establish a harmonised, market-based framework for hydrogen network development, covering areas such as market access, third-party access (TPA), tariffs, and unbundling. Notably, negotiated TPA may be used as a transitional measure until 2033, after which regulated TPA will become mandatory under an entry-exit model.

(3) The Regulation also provides for the creation of hydrogen network codes, which will set detailed technical and operational rules. Every three years, the European Commission will publish a priority list of topics for new codes, starting one year after the establishment of the European network of network operators for hydrogen (ENNOH). Given the complexity of the process, the first hydrogen network codes are unlikely to be in place before 2027.

(4) In the meantime, some Member States have begun developing hydrogen networks and putting in place financing mechanisms, including inter-temporal cost allocation mechanisms, to support investments. Currently, only two practical examples of inter-temporal cost allocation methodologies exist: Germany's inter-temporal cost allocation framework for financing its core network, and a similar but distinct approach under development in Denmark. Both are complemented by emerging national rules for network access and operation. However, these initiatives are still in their early stages, and there is insufficient evidence to assess their effectiveness or generalise best practices.

(5) Experience in this area remains thus limited, and the regulatory requirements of a fully developed EU hydrogen market are still evolving. As such, national frameworks must stay flexible and avoid locking-in design choices that could conflict with future European network codes. Balancing regimes, capacity allocation mechanisms and capacity products, tariff structures and methodologies are all areas that are hardly avoidable when kick-starting the hydrogen market, however, expected to be harmonised by European network codes. Regulatory authorities should consider the potential impact of these codes and communicate the associated risks clearly to stakeholders to support informed decision-making.

(6) In this context, developing inter-temporal cost allocation mechanisms faces a double challenge: a lack of proven models and the absence of a definitive EU market

design. Given these uncertainties, premature harmonisation should be avoided. Instead, this analysis is focused on high-level principles and approaches. The Regulation mandates ACER to issue a recommendation on the inter-temporal cost allocation methodologies and update them every two years, allowing future iterations to incorporate more operational detail as the hydrogen market and regulatory framework mature.

2. HYDROGEN NETWORK DEVELOPMENT CHALLENGES

2.1. Cost recovery and risk mitigation

(7) Capital intensive infrastructure investments of energy networks face the challenge of recovering costs over a long period of time, during which demand for using the network is to a certain extent unknown, thus creating volume risk. For natural gas and electricity transmission networks with proven demand, the relevant EU regulatory framework addresses this challenge by means of cost recovery via cost-reflective transmission tariffs. These tariffs are based on a regulated allowed revenue, or target revenue, which considers appropriate depreciation of the investment and includes the cost of capital and operating expenditures. In the natural gas market and under a revenue cap regime[1], the tariffs ensure the recovery of the allowed revenue annually. Any under-recoveries that may occur each year, e.g. due to deviations from demand forecasts, are recovered in subsequent periods. This ensures that, when tariffs are applied over the life of the network, they allow the full recovery of its cost, providing a security over the volume risk, which is eventually borne by the users of the network. This approach may evolve due to the Union's decarbonisation targets changing natural gas consumption, which could result in higher volume risks the operators may need to bear in the future or decommissioning of networks.

(8) The model described in the previous paragraph is applicable for mature markets with an established and substantial demand base that, due to its size, could undertake fluctuations in tariffs stemming from unpredictable variations of demand. In the case of hydrogen transmission networks, there are two differences compared to the natural gas sector that require adaptations to this model. First, the networks are largely designed to account for the expected future demand; hence demand in the early stages of the development is not sufficient to fully recover the costs of the infrastructure at affordable tariff levels. Second, the uncertainty around the development of demand does not ensure full recovery of the costs of the investment.

2.1.1. Challenges for the hydrogen network development

(9) In its early development stage, the hydrogen sector is characterised by several uncertainties that affect the development of a new market. ACER addressed this point

[1] Under a price cap tariff regime, the volume risk is fully transferred to the network operators; they may under-recover their annual costs if volumes are lower than expected, but they also benefit from higher recovery in case of increased volumes.

to stakeholders in a public consultation held in March 2025. Responses to the public consultation provided useful insights on the risks perceived by stakeholders[2]. For hydrogen networks, the risks can be categorised into two main categories: price or market risk, and regulatory risk, including unforeseen changes in the regulatory framework. The importance of these risks depends on the nature of the market actors whereas hydrogen consumers and producers are more exposed to price risks compared to infrastructure operators.

(10) The price risk is the risk related to the higher price of sustainable (notably renewable) hydrogen compared to its carbon intense alternatives. It constitutes the main uncertainty affecting all stakeholders along the value chain. The current price gap between renewable hydrogen production costs and consumers' willingness to pay is significant[3]. Despite optimistic projections, there is a high uncertainty regarding the potential for cost reductions, primarily related to the speed of technology scale up and the cost of carbon-free electricity that shall further decrease to encourage the development of the hydrogen sector. Expectations for significant cost reductions, on the other hand, prevent potential users of hydrogen from adopting it in the early stages.

(11) The price risk and the lack of an established market discourage hydrogen users and producers from entering into long-term offtake agreements, which, in turn, exposes network operators to volume risk complicating efforts to secure private investment for network development. At the same time, the absence of delayed roll-out of hydrogen networks increases uncertainty for producers and consumers, as reliable infrastructure is a prerequisite for scaling supply and demand. This vicious circle of uncertain demand, supply, and infrastructure impedes the development of the hydrogen market.[4]

(12) Regulatory risks are also important for the development of the market affecting all stakeholders, albeit in various ways. For hydrogen users and suppliers, key sources of regulatory uncertainty include the implementation details of the European and national hydrogen-related targets and quotas and the ambiguity around low-carbon hydrogen. Hydrogen infrastructure operators, particularly hydrogen network operators (HNOs), are similarly affected by delays in the adoption of the Hydrogen and Decarbonised Gas Market package and the lack of clarity surrounding the development of national regulatory frameworks.

2.1.2. Cost recovery in hydrogen transmission networks

(13) Cost recovery during the initial phase of the development of the sector faces the challenge of setting tariffs while the demand is too low compared to the full capacity

[2] A summary of the responses and ACER's reaction can be found here.
[3] For example, see chapter 3 of ACER's 2024 report on European Hydrogen Markets.
[4] This includes uncertainty about lack of funding for producing renewable hydrogen, permitting and lock-ins to expensive technologies and inputs including competition from alternative sources.

of a network merely designed to accommodate future demand growth. The standard tariff setting methodologies, based on a straight-line depreciation without cost shifting over time, would result in prohibitively high tariffs, potentially rendering pipeline transportation not feasible and unaffordable for users. For this reason, the development of infrastructure in the absence of significant demand volumes requires instruments to decrease tariffs in the early stages, possibly recovering the missing revenues at a later stage.

(14) The Regulation recognises the challenges during the early phases of hydrogen networks development "*… where booked capacity is low compared to technical capacity and uncertainty as to when future capacity demand will materialise is significant"* (recital 10). It therefore allows for derogations relating to the use of cross-subsidies, or financial transfers, for financing hydrogen networks contributing "*… to reasonable and predictable tariffs for early network users and de-risk investments made by network operators…"*. In addition, the Regulation provides the possibility to Member States to allow the recovery of network costs over time via an inter-temporal cost allocation mechanism, ensuring that future users duly contribute to the initial network costs. It further specifies that Member States may complement these mechanisms with measures to cover the financial risks of hydrogen operators. Both mechanisms are subject to the approval of the regulatory authorities[5]. Furthermore, ACER shall issue recommendations on the inter-temporal cost allocation methodologies and may do so on elements of the financial transfers that might be used to finance hydrogen networks.

(15) Cost shifting can also be achieved via existing regulatory tools such as the choice of the depreciation method. In this case, a back-loaded depreciation profile can be used, pushing for the recovery of the allowed revenue at a later point in time[6].

(16) Without complementary measures, cost shifting, either via an inter-temporal cost allocation mechanism, an appropriate depreciation method, or both, increases the volume risk, as more costs are scheduled to be recovered in the future by highly uncertain demand. This impacts the financing conditions of the HNOs and, depending on the demand growth profile, may lead to liquidity problems for HNOs if revenues are not enough to recover operating expenditures (e.g. fuel costs for compression, salaries, etc.) and payback debt instalments.

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[5] Article 5(3) of Regulation (EU) 2024/1789 states that national regulatory authorities shall approve inter-temporal cost-allocation methodologies, however, it does not specify which party is responsible for designing these methodologies. While this document assumes that national regulatory authorities may design the methodologies, it recognizes that other parties could also take on this role. Accordingly, solely for reasons of clarity and conciseness, this Annex refers exclusively to national regulatory authorities as the designing entities. Nonetheless, such references shall be understood to include all other potential designing parties, mutatis mutandis.

[6] The Dutch regulatory authority, ACM, demonstrated however in a recent publication that the impact of different depreciation methods may have on the tariff is limited.

(17) In general, Article 17 of the Regulation applies to hydrogen networks under regulated third-party access (TPA) whereas cost-reflective and non-discriminatory tariffs are required.[7] Cost recovery mechanisms, including inter-temporal cost allocation, should be designed taking into account the tariff regime applicable to hydrogen transmission networks, the details of which are important parameters for the design and effectiveness of these mechanisms. As an example, the treatment of interconnection points may further affect the choices regarding the instruments used to recover the costs of the network like the inter-temporal cost allocation mechanisms. Article 7(8) of the Regulation provides the option for regulatory authorities to set tariffs equal to zero at interconnection points. In case of zero tariffs, cost recovery of cross border costs could be based on financial compensation mechanisms, in line with Article 59 of the Directive [8].

2.1.3. Risk mitigation in hydrogen transmission networks

(18) Due to the uncertain development of hydrogen demand, full cost recovery at affordable tariff levels is not guaranteed for future hydrogen networks. Lower demand compared to the demand the network is designed for would result in high tariffs for network users, potentially increasing risks of spiralling tariff effects and hindering the development of the market. As a worst-case scenario, excessive costs of hydrogen, exacerbated by high tariffs, could eventually lead to a failure in the market development and to the stranding of hydrogen assets. Furthermore, the current market risks make it difficult for network users to sign long-term capacity commitments. A recent paper from the Oxford Institute for Energy Studies highlighted the lack of a market price for hydrogen as a barrier not allowing for indexation options or appropriate signals for contract-for-differences, which could otherwise facilitate long-term contracts[9]. Under such an uncertain market environment, additional measures to cope with the volume risk over the lifetime of the hydrogen network and ensure the full recovery of the investments are necessary.

(19) While in the case of electricity or natural gas markets, the volume risk can largely be borne by the large existing demand pool from current network users, in

[7] Article 7(8) of the Regulation mentions that from 1 January 2033, or where a Member State decides to apply regulated third-party access to hydrogen networks in accordance with Article 35 of Directive (EU) 2024/1788 before 1 January 2033, Article 17 of this Regulation shall apply to tariffs for access to hydrogen networks and the obligations on transmission system operators set out in Article 17(1), (2), (4) and (5) of this Regulation shall apply to hydrogen network operators.

[8] Article 59 of the Directive allows HNOs involved in the development of cross-border hydrogen networks to request for a cross-border cost allocation plan, subject to joint approval by respective regulatory authorities. From 2033 and for cross-border hydrogen networks where no tariffs are charged at the interconnection points between Member States, involved HNOs shall develop a financial compensation system and submit it to the respective regulatory authorities for a joint approval.

[9] Oxford Institute for Energy Studies, *"Contracts for Difference: the Instrument of Choice for the Energy Transition"* available here.

the nascent hydrogen market the absence of a mature hydrogen demand could potentially lead to excessively high tariffs and hinder the development of demand.

(20) In the natural gas sector, especially during the later waves of infrastructure development, open season procedures with binding demand indications and long-term capacity bookings were a frequently utilised tool to develop infrastructure. The commodity-related price risks for gas were much lower compared to those faced today by hydrogen, in particular renewable hydrogen. Moreover, in the nascent hydrogen market, the initial demand levels are significantly lower than the estimated future system needs, therefore developing networks relying only on binding capacity bookings imposes the risk of developing very limited networks, well below the future needs increasing risks of higher costs for network upgrades and congested networks.

(21) These challenges of cost recovery and risk mitigation result mainly from the fact that network investments are designed to accommodate demand that is expected to materialise in the future and that is highly uncertain at the time of the final investment decision. An alternative approach that reduces the complexity of cost recovery and risk mitigation consists of a gradual deployment of the infrastructure that is closer to the development of specific demand increments. Table 1 gives an overview of the characteristics of the two approaches.

Table 1: Assessment of the two main possible approaches to the development of the hydrogen network.

	Gradual approach	**Large-scale network development**
Infrastructure needs	Limited in the beginning mainly connecting local production with end-users (locally or in other markets); as market matures wider interconnection appears.	Large, developing at least a national core network, contributing to a European hydrogen backbone.
Demand	Well-defined demand identified largely based on user commitments.	Large, but uncertain demand based on long-term forecasts and targets.

Regulatory approach	Simple regulation – at least before 2033 – with basic operational rules would suffice.	A more ambitious and wide regulatory approach is needed – likely affecting areas to be later regulated by EU-wide network codes, which might lead to regulatory lock-in and fragmentation of regulatory regimes.
Cross-border effects	Limited effects.	Hydrogen corridors require cross-border coordination and might need cross-border risk allocation. Divergent regulatory approaches in Member States can distort cross-border trade and transport.
Market model	In the initial phases models like a market model for industrial gases delivered through pipelines. A more complex model can be delivered gradually, at a pace organically adapted to the rate of demand growth.	A market model analogous to natural gas or electricity is targeted from the beginning of network development – even in early periods and at Member States where there is yet no viable business case for widespread hydrogen adaptation.
Risk	Standard operational risks.	High volume risk, related to the price risk of renewable hydrogen.
Need for an intertemporal cost allocation mechanism	As the gap between network development and demand growth is limited, the local networks may be developed without the need to allocate costs to future users and mitigate demand risks.	The uncertainty of demand ramp-up and the low initial demand compared to the large infrastructure needs warrants the application of additional regulatory mechanisms.

(22) In a context where early and future network users cannot provide a guarantee over the financing of the infrastructure there are, essentially, two other parties that can bear this risk: HNOs and Member States. Allocating risks to these two parties has different implications.

(23) In the cases of HNOs, bearing the risk of cost recovery of the full network is less efficient and potentially very costly, as it would increase the overall financing costs. In addition, unbundled HNOs subject to regulated third party access conditions have few instruments to impact the utilisation of the network. Fully allocating volume risk to HNOs would therefore be inefficient and would require high (probably prohibitive) risk premiums to be paid by the users.

(24) On the other hand, inappropriate network planning, relying on poor demand forecasts increases the volume risks of the network. Thus, safeguarding HNO completely from all the volume risk related to network planning and guaranteeing regulated profits on all investments might not create adequate incentives for comprehensive demand forecasts. Hence, allocating a reasonable amount of risk to HNOs shall be considered as it incentivises efficient network planning and operation. At the same time, allocating more risk to HNOs affects the financing of the network and the remuneration and should be carefully considered to not increase the overall network costs disproportionally. Regulatory oversight over forecast demand scenarios and infrastructure planning, as foreseen in the Directive and with the close involvement of hydrogen users, can also contribute to efficient network planning.

(25) Member States and public institutions will play a primary role in guaranteeing large volume risk in the nascent hydrogen market, by providing the necessary guarantees to mitigate the volume risk of the respective infrastructure. Member States can do this using different instruments to ensure the repayment of the costs annually or within longer periods. These instruments can be complemented with the use of inter-temporal cost allocation mechanisms, additional direct support from Member States, and long-term commitment from network users.

(26) State support can be combined with the requirement for a minimum level of commitment from network users. That approach could be used to manage the risk undertaken by the state and encourage private engagement. This approach is adopted in Denmark (see section 3.2), where the state is committed to provide funding and additional support to lower hydrogen transmission tariffs to affordable levels under the condition that at least 0.5 GWh/h (appr. 12-17% of the capacity of the network) will be booked by users for the first 10 years of its use.

(27) Encouraging long-term commitments is also possible through incentives embedded in the market rules, e.g. by providing discounts for longer term capacity bookings. Such measures, however, need to be carefully balanced against their effects over the costs allocated between early and future users of the network, and be in line with the regulatory principles of cost-reflectivity, non-discrimination and minimization of cross-subsidisation.

2.1.4. Cross-border risk mitigation

(28) Where Member States introduce guarantee schemes to ensure the full recovery of transmission investments, these are likely to be targeting national networks in the first stages of the market development, like in the case of the German approach (see Section 3.1). The development of cross-border infrastructure might require, however, Member States to provide guarantees that facilitate network development outside that Member State.

(29) In a simple infrastructure project where a pipeline crosses Member State A to supply Member State B, there is a risk associated with the transit use of the pipeline in Member State A and that must be addressed. According to the principles applied so far in natural gas, users of Member State A would bear a significant amount of the risk of this transit infrastructure. However, if the infrastructure is built mainly to supply Member State B, it could be argued that Member State B should also mitigate this risk.

(30) The risk of not recovering the full investment associated with the infrastructure in Member State A is related to two factors: first, the possibility of demand in Member State B not developing as expected. Second, as the market develops, there could be alternative routes to supply Member State B. Over time, there could be pipe-to-pipe competition, potentially due to source competition rendering the route in Member State A as not competitive. These two factors create a risk of Member State A not recovering its full investment costs.

(31) To address these risks, investments in cross-border hydrogen networks might require cross-border risk allocation instruments. Currently, there is no common methodology at EU level explicitly addressing this challenge. The allocation of risks between beneficiaries of cross-border infrastructure can thus be part of an overall infrastructure development agreement between the relevant parties that includes planning, financing and risk mitigation at once. It could be possible, however, that in the future a more coordinated EU approach might facilitate such agreements. The tools already used for natural gas, including tariffs and cross-border cost allocation mechanisms (CBCA) can be used as a basis to design cross-border risk allocation mechanisms (CBRA) that might assist the build out of cross-border infrastructure. Notably, such harmonised mechanisms would be built around methodologies relying on multiple assumptions and would require Member States (at least partially) to provide guarantees for costs incurred by HNOs in another jurisdiction. This could also take the form of long-term capacity bookings at interconnection points, possibly backed by public institutions, as a way for a Member State to commit over a certain route, hence giving additional certainty on the cost recovery of a hydrogen infrastructure in a neighbouring Member State. Notably, the implications

of the various approaches towards cross-border risk allocation need to be thoroughly examined[10]. In the absence of harmonised EU market rules, this would call for enhanced cooperation between Member States and regulatory authorities and requiring the harmonisation or coordination of allowed revenue methodologies across the relevant Member States.

3. EXISTING CASES

3.1. The German scheme

(32) In October 2024, the German regulatory authority, BNetzA, approved a German hydrogen core network of 9,040 km. as proposed by fifteen gas TSOs[11]. The network is expected to cost EUR 18.9 billion and nearly 56% of the hydrogen network is planned as repurposed natural gas pipelines. The network links Germany to several other EU Member States and connects major import routes with key demand hubs. A distribution grid is planned for a later phase. The hydrogen core network is expected to be completed by 2032 or, if demand develops not as initially expected, by 2037. It is designed to accommodate around 101 GW of entry capacity, of which 58 GW refer to imports, and 87 GW of demand.

(33) To enable the financing of the project, the German government designed a mechanism consisting of an inter-temporal cost allocation mechanism complemented by a financing and risk sharing mechanism. The inter-temporal cost allocation mechanism shifts the recovery of costs through tariffs towards the future in a way that it avoids prohibitively high tariffs in the initial ramp-up phase. Further, financing will be provided by the public development bank KfW to the network operators to cover any financing needs during the first phase when revenues are not enough to cover the annual costs. As demand grows and revenues increase, the operators will be able to repay the provided liquidity. However, if the expectations for demand prove too optimistic and demand lags significantly behind, there is a risk that the tariffs will not be enough to fully recover the costs. This risk is shared between the German State and the network operators, providing an incentive for the latter to take rational economic decisions. According to the risk sharing scheme, if the accumulated deficit is not balanced by the end of 2055, 76% of the remaining deficit will be covered by the German State while network operators will bear the rest. If, by 2038, it is obvious that demand will not reach the levels necessary to cover the costs through reasonable tariffs, the German government may decide to cancel the process and take on any losses accumulated by network operators, while gaining control of the network. As above, the network operators must bear a deductible. Dependent on the point in time of the cancellation the deductible is set between 16% and 24%.

[10] For example, heterogeneous application of the necessary risk mitigation measures among different cross-border routes may impact the competitiveness of more economic solutions.
[11] More information can be found here.

(34) The inter-temporal cost allocation mechanism, known as WANDA, establishes a unified framework for tariff regulation and long-term cost recovery for the hydrogen core network. This mechanism is designed to ensure full financing of infrastructure investments while maintaining non-discriminatory and affordable access to the hydrogen network.

(35) According to the national rules on hydrogen transmission network tariffs[12], hydrogen core network operators charge tariffs for the provision of firm annual entry and exit capacity to the hydrogen network. These tariffs are calculated in €/kWh/h/a and apply exclusively to non-interruptible capacity. No separate flow-based charge is levied for the physical transportation of hydrogen between network operators. The tariffs are set jointly by all hydrogen core network operators on a non-distance-related basis. Each year, the operators forecast the sum of entry and exit capacities and divide the approved total network costs for the system accordingly. The resulting tariff must be published by 1 November of the preceding year and remains fixed throughout the calendar year. The application of a joint tariff is supplemented by a revenue sharing (or balancing) system ensuring that all network operators receive their proper share of revenues.

(36) To facilitate the development of a core-network, an inter-temporal cost allocation mechanism is applied. The mechanism introduces a specific transitional tariff structure, the ramp-up tariff, which deviates from the standard cost-based tariff. The ramp-up tariff is applicable during the designated "payback" period from 1 January 2025 until 31 December 2055. This tariff is intended to gradually recover the full investment costs over time. It is determined by the German regulatory authority, BNetzA, and indexed annually to inflation using consumer price indices published by the German Federal Statistical Office.

(37) The ramp-up tariff is based on the initial design assumptions and ensures full recovery of the inter-temporal cost allocation account by the end of 2055, if inflation-adjusted and unchanged. A triannual review of the tariff begins in 2028 to verify whether assumptions remain valid. If cost-recovery is jeopardized, BNetzA will adjust the tariff or, ultimately if expected market development does not materialises, set it at a level that maximizes revenue potential.

(38) Any mismatch between actual revenue (calculated for each HNO as the revenue from tariffs adjusted by the revenue sharing system) and the approved network costs is recorded into an inter-temporal cost allocation account. If actual revenues fall short, the difference is posted to this account. The account is considered "balanced" when its cumulative value returns to zero. The account is also considered balanced if the repayment of the financing provided as described in paragraph (33) takes

[12] Hydrogen network tariffs ordinance (WasserstoffNEV).

place earlier than the balancing of the inter-temporal cost allocation account through the tariff-based revenues.

(39) To ensure fair distribution of tariff revenues among operators, monthly revenue balancing payments are implemented. Each operator's share of approved annual costs is compared with its share of actual tariff revenue. The resulting difference defines the operator's annual balancing obligation or credit, which is then split into monthly instalments (1/12 of the annual amount). Operators with negative monthly balances (i.e., under-recovered costs) receive pro rata compensation from those with positive balances. To mitigate financial risk during the ramp-up period, operators are eligible to receive payments from the KfW (see paragraph (33)(33)), which is not considered a cost-reducing factor under the tariff market rules.

(40) Special rules apply to lifetime of the assets, return on equity (remuneration), and the treatment of expenditures:

- Asset lifetime is set at 35 years, with specific provisions for repurposed infrastructure.
- For the core network, the return on equity for new assets is by law fixed at 6,69 % until 31 December 2027. The return on equity for repurposed assets that were capitalized before 2006 is calculated based on the return on equity for new assets and is lower to compensate for the fact that the interest basis is higher.
- Historical expenditures and related interest costs can be retrospectively included.
- Potential revenues and expenditures caused by inter-HNO revenue sharing payments are recognized as tariff-related items in comparisons between targeted and actual costs.
- Residual costs for decommissioned or underutilized assets may be recognized when no alternative use is viable.

(41) All costs must be reported to BNetzA by 30 June of each year. No additional or supplementary tariffs may be levied outside this mechanism. BNetzA retains the right to order payment of costs and enforces strict compliance with the approved framework.

3.2. The Danish scheme

3.2.1. Infrastructure outline and future investments

(42) In Denmark, the fully state-owned electricity and gas TSO, Energinet, has been tasked to develop and operate a hydrogen transmission network. Energinet has proposed a hydrogen back-bone network spanning across the country; While the political majority is currently in favour for the development of a full hydrogen backbone in Denmark including access to underground storage, as of February 2025, a decision has been taken to go ahead with the support for the development of the part of the network in the southern part of Jutland, called the Seven.

(43) The Seven will connect renewable hydrogen production in Esbjerg (from wind production in the North Sea) to the German Core Network at the Danish German border, Ellund. It will consist of a new pipeline between Esbjerg-Egtved and a repurposed pipeline between Egtved-Ellund converting one of two gas pipelines into transportation of hydrogen. It is expected that the infrastructure is operational in 2030. Energinet will be provided a state loan of approx. 950 million euros corresponding to the investment of the Seven ('7-tallet').

3.2.2. User commitment

(44) To support this investment, the state requires future users to commit to purchasing at least 0.5 GWh/h of yearly capacity (entry and exit) for a minimum period of 10 years. corresponding to appr. 12-17% % of the network's capacity.

(45) The HNO expects to launch a user commitment process (Open Season) for the hydrogen network for the binding sale of capacity on a first-come-first-serve principle. The process is expected to be open in 2026. It is also expected that a 6-month option will be provided to users committing so they are able to finalize offtake agreements before finalising the capacity agreement. The HNO will offer entry and exit yearly capacity for a contract length of up to 15 years. If oversubscription occurs, a capacity auction will be conducted to allocate capacity for each affected year. The user commitment process and capacity allocation methodology will be subject to regulatory approval by the NRA.

3.2.3. Inter-temporal cost allocation mechanism

(46) The Danish state has required that it will only support the financing of the hydrogen infrastructure if an inter-temporal cost allocation mechanism is used to ramp up the demand for network usage and development of a hydrogen market. The Danish Utility Regulator (DUR) has in accordance with the Regulation article 5(3) been given the competence to draft an Executive Order and develop and implement this mechanism. The inter-temporal cost allocation mechanism will be a part of the revenue cap regulation that the HNO will be subject to. DUR expects to draft the Executive Order and implement the relevant economic regulation in 2027.

(47) The inter-temporal cost allocation mechanism aims to shift parts of the annual costs to a later point in time, where increasing demand for transportation of hydrogen expects to materialize. The difference between the actual annual costs and the costs considered in the mechanism will be transferred to an amortisation account whereas DUR will set an annual allowed revenue to reflect this. The time horizon for the mechanism will be set to 30 years, but with the flexibility of both increasing and decreasing the period. The mechanism will set an annual inter-temporal cost allocation revenue cap, which will be reassessed every year or biannually to adjust for substantial changes in demand projections, costs, WACC and other revenue cap setting parameters. The HNO will bear the risk of stranded assets leading from a spiralling effect of excessively high tariffs due to factors such as cost overruns.

3.2.4. State support scheme

(48) In addition to providing a state loan for development of the infrastructure, the Danish state will, grant an annual subsidy of up to 37 million euros (2025) for 30 years to help recover the HNOs annual costs and reduce average transport costs to approximately 9.5 euros/MWh that aligns with users' willingness to pay.

(49) The purpose of the subsidy is to cover the risk of demand not materializing, therefore it will only be adjusted based on annual capacity sales, decreasing if sales exceed expectations and increasing if they fall short, up to a predefined ceiling. Any risks of increased costs are to be borne by the HNO through tariffs (decreased costs result in lower subsidy amounts, with the tariff level remaining the same).

(50) DUR expects to implement the annual subsidy by two phases. Firstly, DUR will estimate the unsupported inter-temporal cost allocation revenue cap level, after which the state will evaluate how much direct support will be needed to cover the potential volume risk. Secondly, DUR will estimate and publish a supported inter-temporal cost allocation revenue cap level that includes the state subsidy by deducting it from the total costs. DUR is considering mitigating some of the risks arising from demand uncertainty by assuming a more conservative demand projection compared to the projections used for the network planning.

3.3. The Dutch case

(51) The Netherlands provide another example of a core network development plan. The plan foresees a gradual development of a network connecting hydrogen production and supply sites (electrolysers and terminals) with industrial clusters and large-scale underground hydrogen storage. The network will eventually link the Dutch system with Germany and Belgium. Initially, the network was planned to be ready by 2030 at an estimated total cost of EUR 1.5 billion. The Dutch State reserved approximately EUR 750 million as support to complement revenues from network tariffs. It was envisaged that the State support would be sufficient to derisk the investment in the initial ramp-up phase up to 2031 leading to affordable network tariffs. No inter-temporal cost allocation mechanism is foreseen so far, and the final amount of the State support would be determined by the actual use of the network by 2031. In the current setting, the government maintains the right to amend the development plan, while the network operator must provide access to third parties in an objective, transparent and non-discriminatory manner.

(52) In December 2024, the hydrogen network operator, Hynetwork (a subsidiary of the methane TSO, Gasunie), issued an adjusted roll-out plan which was then submitted to the Minister of Climate and Green Growth for approval in March 2025. The new plan foresees the use of fewer repurposed gas pipelines which together with an increase in construction costs result in a current cost estimate for the Dutch network of EUR 3.8 billion. The new plan also foresees delayed commissioning of the full hydrogen network with the target set in 2033. Moreover, new projections

by the Netherlands environmental assessment agency, PBL, indicate a slower progress in the development of electrolysers, expecting 1.2-1.5 GW by 2030 down from 4 GW as initially planned.

(53) These new developments lead to a rethinking of the financial model and a request from the HNO towards the government and the regulatory authority, ACM, to introduce an inter-temporal cost allocation mechanism. At this stage, the tariffs are set by the government while ACM has a limited role. From 2033 onwards, ACM is expected to regulate the tariffs. Currently, a single uniform tariff at all entry and exit points of the network is set at 21.13 euros per kW (price level 2023) until the tariffs will be regulated by ACM (i.e. a shipper would need to pay 42.26 euros per kW in total)[13].

(54) In a position paper issued in May 2025, ACM highlights the challenges with the financing of the network based on the latest estimates by the HNO. It highlights substantial increases in the tariffs if standard, cost-reflective tariffs shall apply by 2033, and thus supports the adoption of measures to mitigate the problem. Among these measures are the introduction of an inter-temporal cost allocation mechanism, the request by the HNO for commitments by network users before any final investment decision and several other regulatory instruments to mitigate the impact on tariffs.

(55) The Dutch case illustrates the significant uncertainties regarding estimated network development costs, and hence the need for appropriate planning and robust cost calculations. It also highlights the need for close coordination between the government, regulatory authorities, and network operators in a timely manner to design viable financing mechanisms, providing stability and predictability to the users of the network.

4. ELEMENTS OF THE INTER-TEMPORAL COST ALLOCATION MECHANISMS

4.1. Introduction

(56) Under a standard regulated third-party access regime, network investment costs are recovered over the economic lifetime of the network via tariffs set over a certain period (e.g. annually). The asset base for a given network, i.e. the amount of the investment that needs to be recovered annually in a regulated market regime, decreases over time due to depreciation. Under the assumption of a straight-line depreciation, this amount decreases at a constant rate. Similarly, assuming a constant rate of return, the return on the asset base (remuneration) will also be lower at the end of the period due to a smaller asset base. Tariffs are then set by spreading annual costs, or allowed revenues, over the demand for the network. Applying this approach in a situation where a hydrogen network is designed to meet the needs of a

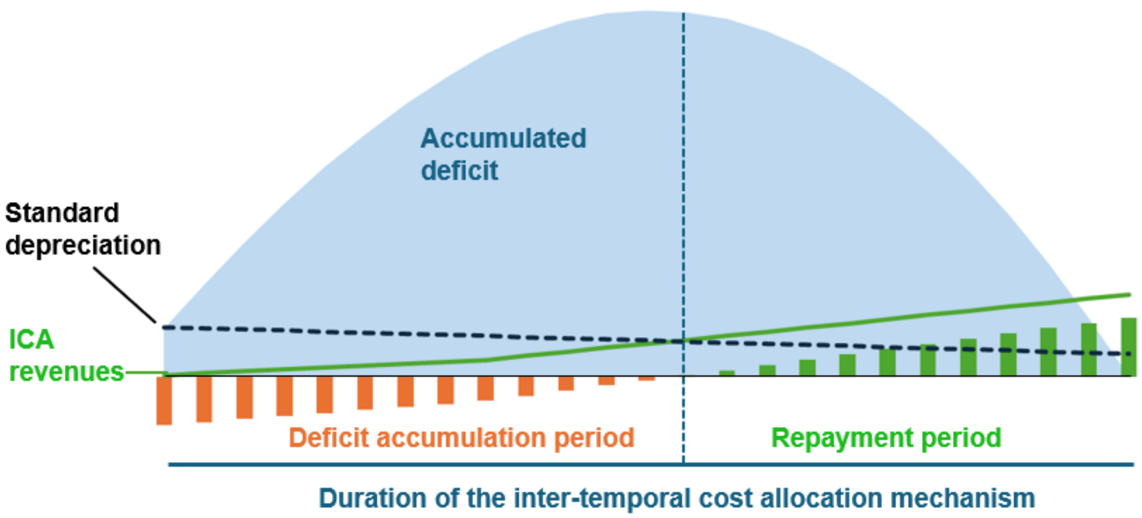
[13] The tariff is calculated based on estimated capital cost of 1.545 billion euros, WACC equal to 4.04%, operating costs of 40 million euros annually and a demand for capacity of 4 GW.

growing future demand, would result in early users having to pay disproportionately higher tariffs than the future users for the same service.

(57) The primary goal of an inter-temporal cost allocation mechanism is to mitigate these high network tariffs during the ramp-up phase of the hydrogen market and to distribute the network costs duly between the early adopters of hydrogen and future users. The mechanism works by shifting the recovery of a part of the network costs from the early years of operation to later periods. The deficits incurred during the initial ramp-up phase are typically placed in a separate regulatory account (inter-temporal cost allocation account or debt account). This account is balanced over time as hydrogen demand increases, and sufficient revenue are obtained by over-recovery.

(58) Figure 1 illustrates a case where the inter-temporal cost allocation mechanism recovers costs through a levelised tariff that is stable over time. In the first phase of the mechanism, when demand ramps-up, the revenues are not enough to recover the annual costs of the network. The accumulated deficit is however fully recovered by the revenues during the second phase of the mechanism, where tariffs are higher than the "standard" ones allowing for sufficient annual over-recovery.

Figure 1: Illustrative example of an inter-temporal cost allocation mechanism.



(59) It should be noted that inter-temporal cost allocation mechanisms are only instruments for allocating the costs and risks[14] related to hydrogen infrastructure

[14] In principle, an intertemporal cost allocation mechanims in its most simple form may not even provide for risk mitigation, as temporally skewed demand can theoretically exist without uncertainties; this is of course not the case in the current European hydrogen landscape where the skewed demand curve is paired with significant uncertainties.

investments among the network users in different time periods. They are not tools for identifying the optimal way of sharing costs and risks between the operators, the network users and the state, but rather depart from the existence of a clear agreement on the sharing of costs and risks between the relevant parties.

4.2. The overall regulatory and market framework

(60) According to the Regulation, the inter-temporal cost allocation mechanism must be approved by the regulatory authority. Hence, the designation of the regulatory authority responsible for the regulation of the hydrogen market is a pre-requisite. Insofar the transposition of the Directive is pending[15], the legal gap needs to be filled with appropriate national legislation. It is important to provide legal and regulatory clarity by assigning all competences and resources necessary to fulfill the task, especially regarding competences with regards to tariff setting. Member States are advised to quickly transpose the Directive and together with regulatory authorities prepare the financing and regulatory framework needed during the early development steps of a hydrogen market. Implementation of the Directive will also enable regulatory authorities to gain oversight over the ten-year network development plans improving the analysis by network operators and better link the planning process with cost recovery and market development considerations[16].

(61) The inter-temporal cost allocation mechanism will be called to operate in conjunction with certain market rules. Hence, market design elements, such as the design of the tariff regime and the market rules on network access and operation (e.g. balancing, capacity allocation) defining the various capacity products offered to the network users, may influence the mechanism – or vice versa. While the gas decarbonisation package sets the overarching principles of the hydrogen market structure, the details of the hydrogen market design are currently a national prerogative since these markets are not operational. Currently, national market rules are in the making in Germany and under design in Denmark and Belgium.

(62) At the same time, for an inter-temporal cost allocation mechanism to ensure cost recovery, be stable and predictable while providing clarity to the network operators and users, the overall market framework needs to be developed in a timely manner – and in some cases at the same time as the approval of an inter-temporal cost allocation mechanism. A particular regulatory challenge stems from the fact that while national market rules should adapt to the forthcoming EU network codes for hydrogen, inter-temporal cost allocation mechanisms will normally have a much longer duration. It is therefore advisable that the aspects of national market rules impacting the inter-temporal cost allocation mechanism are designed with a view to allow for some degree of flexibility, while at same time providing regulatory clarity. When

[15] Member States need to transpose the Directive into national legislation by 5 August 2026.
[16] According to article 78(1)(ee) of the Directive regulatory authorities approve and amend the network development plans.

hydrogen markets of Member States are interdependent, enhanced cooperation and coordination between the relevant parties (governments, regulatory authorities and HNOs) is encouraged to foster the development of an internal energy market and reduce the possibilities of market fragmentation before the network codes are adopted[17].

4.3. Designing an inter-temporal cost allocation mechanism

(63) As per the responses of stakeholders in the public consultation an inter-temporal cost allocation mechanism should provide (ranked in descending order[18]) stability and predictability, transparency and reproducibility, flexibility and adaptability, simplicity, and understandability. These principles should be considered when deciding on certain elements of the mechanism.

(64) The inter-temporal cost allocation mechanism refers to the identification of an appropriate cost recovery pathway over the predefined period of the mechanism (also called payback period). While the principle is simple, the design of an inter-temporal cost allocation mechanism is challenging. Key primary decisions shaping the level of complexity of the mechanism include:

- What is the scope of the mechanism, i.e. which networks elements will be covered by the mechanism, and what are the relevant costs (including decisions like the economic lifetime or remuneration of investments, operating expenditures, etc.).
- What is the expected demand profile over time to be used for the cost recovery assumptions and what is the level of uncertainty in terms of both growth levels and growth rate.
- What is the duration of the mechanism (payback period).
- What is the appropriate level of the tariff(s).
- What is the form of complementary support schemes or de-risking mechanisms and how they interact with the mechanism (e.g. claw-back provisions, user commitments).
- How should risks be allocated to the affected parties (government, early and future users, system operators, etc.).
- How to cope with potential cost overruns and deviations of demand development and how does the latter affect the (residual) infrastructure needs.

[17] For example, this might be the result of prolonged lead times and transitory periods for the implementation of network codes in certain jurisdictions to provide smooth transition to the new regulatory regime.
[18] See also the results of the public consultation.

- How to monitor and reassess the model established in the early phase, with what frequency (if any) should its assumptions be reviewed – and provide clarity on how it will be fitted to reality.
- What are the potential implications of the mechanism design to cross-border trade, and how to assess and coordinate on these matters with neighbouring countries.

4.4. Inter-temporal cost allocation mechanism design elements

(65) This section discusses some key elements of an inter-temporal cost allocation mechanism, raising awareness on various challenges and providing recommendations when possible.

4.4.1. Scope of the inter-temporal cost allocation mechanism

(66) Article 5(3) of the Regulation refers to inter-temporal cost allocation mechanisms targeting hydrogen networks. As per article 2 of the Directive, hydrogen networks refer to pipeline transmission or distribution networks[19]. In principle, there is no provision preventing the implementation of similar types of cost allocation mechanisms for storage facilities or the design of inter-temporal cost allocation mechanisms that include pipeline networks and other infrastructure[20]. The German mechanism and, so far, the Danish proposed design are applicable only to hydrogen networks, excluding other infrastructure elements.

(67) The Regulation does not further distinguish between networks operating under a regulated and networks operating under negotiated third party access regime. However, it is not expected that the latter would fall into the scope of the inter-temporal cost allocation mechanisms of article 5(3) of the Regulation. First, the regulatory oversight over the cost recovery of these networks is more limited and second, they are developed based on negotiated access agreements hence they would normally not require a centrally approved methodology for cost allocation.

(68) The definition of hydrogen networks includes both transmission and distribution networks. The characteristics of hydrogen distribution networks are expected to vary significantly between and within Member States. For example, based on current national strategies and plans[21], the use of hydrogen in residential areas will probably be limited, hence, meshed distribution networks similarly to natural gas are not generally anticipated. Furthermore, hydrogen consumers are expected to be

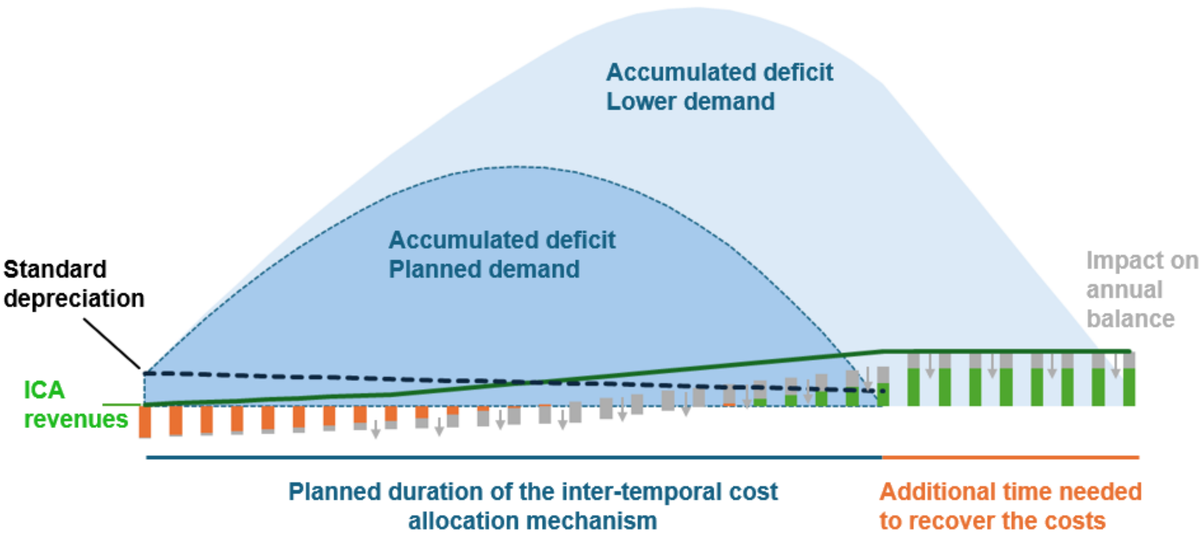
[19] Article 2(21) of the Directive defines hydrogen network as "a network of onshore and offshore pipelines used for the transport of hydrogen of a high grade of purity with a view to its delivery to customers, excluding supply".
[20] In its current proposal, the German regulatory authority, BNetzA, suggests the introduction of discounts to the tariff at exit-points to the storage facilities to reduce the cost of storing hydrogen and thus facilitate hydrogen production based on intermittent renewables.
[21] See for example the relevant analysis in chapter 2.2. of ACER's 2024 report on European hydrogen markets.

large industrial actors that in most cases will be connected directly to the transmission network. The potential for scalability or incremental development as demand is becoming more certain is thus larger for distribution networks than for transmission networks. At the same time, long distribution networks connecting diverse potential users (e.g. industrial and power generation sites) to the transmission network might also be in need for an inter-temporal cost allocation between early and future users, similarly to transmission networks (and possibly for similar guarantees). Hence, the possibility of an inter-temporal cost allocation mechanism for distribution networks should not be excluded. However, due to the differences in the pace at which distribution networks will be developed in different locations, the level of uncertainties the different distribution networks will face, the lack of cross-border impacts, and the way transmission and distribution network operators recover their costs, the implementation of separate intertemporal cost allocation mechanisms may be favourable. Moreover, similar principles and concepts as for the inter-temporal cost allocation mechanisms for transmission networks should apply to the inter-temporal cost allocation mechanisms for distribution networks.

4.4.2. Demand forecasts

(69) A key part of an inter-temporal cost allocation mechanism is the estimation of network demand over time. The demand evolution profile influences the spread of costs over time and the tariff level. A substantial difference between early and future demand means that more costs need to be shifted to the future. The steepness of the demand growth curve also influences the cost allocation over time. The duration of the mechanism may also be fine-tuned according to the expected evolution of demand (see Figure 2).

Figure 2: Impact of lower than initially planned demand on the accumulated deficit assuming the tariff level remains the same. The deficit of the account increases due to lower revenues and the period to recover the full costs increases.



(70) The use of demand estimates during the regulatory period of an allowed revenue is a well-known feature of the tariff setting process in the gas sector. This estimation, however, only covers a short period of time and refers to a market with much bigger demand base and lower uncertainty over short- to mid-term term demand and network costs. In the case of hydrogen, the market is not established, the infrastructure is not in place yet, and uncertainties are present regarding cost developments of both production and transportation of the commodity. In addition, in case of approaches favouring the build-up of a larger core or backbone network instead of gradual network development, the inter-temporal cost allocation mechanism requires the estimation of demand for a longer period, possibly over 30-40 years, increasing the uncertainty of fitting the reality. Large deviations between actual and forecasted demand, especially towards the last period of the mechanism, may have a high impact on the cost recovery or the level of tariffs for the users. Therefore, it is important that the estimations are prudent and based on robust methodologies. Diverging incentives with the possibility of distorting forecast or overinflating the demand expectations should be avoided. Demand projections should be reviewed and approved by the regulatory authorities.

(71) Hydrogen network development plans are normally set to identify the infrastructure needs based on national energy policies[22]. While in principle similar demand assumptions could be used by regulatory authorities to set the tariffs in an inter-temporal cost allocation mechanism, the uncertainties pertaining such assumptions are normally too high. Hence, policy related demand projections could result in low tariff levels that may prove inadequate to recover the costs, if demand does not materialise, increasing the possibility for corrective measures. If the demand profile is skewed towards the future, the room for manoeuvre may be too narrow. On the other hand, considering only a very conservative demand profile, e.g. based only on binding long term commitments and excluding any other potential demand growth, may result in, potentially unnecessary, high tariff levels.

(72) Moreover, the expected consumer base of the hydrogen network is expected to be less diversified and more concentrated than in the natural gas paradigm. Hydrogen will likely be used at a small number of hard-to-abate industrial sectors with limited role in the residential or commercial sector. While initial demand estimates would be based on relevant policy targets and certain decarbonisations commitments by the industry, changes in these commitments or competition with other energy carriers or alternative feedstocks, could lead to cancellation of investment plans and to the loss of significant demand.

[22] Article 55(2) (h) of the Directive states that hydrogen ten year network development plans shall "be in line with the integrated national energy and climate plan and its updates, take into account the state of play in the integrated national energy and climate reports submitted in accordance with Regulation (EU) 2018/1999, be consistent with targets set by Directive (EU) 2018/2001 and support the climate-neutrality objective set out in Article 2(1) and Article 4(1) of Regulation (EU) 2021/1119.

(73) In choosing the appropriate demand evolution profile over which the cost will be distributed over time, regulatory authorities could use any binding long-term commitments and projects with final investment decisions or secured financing (such as PCI/IPCEI projects) as the minimum demand basis. Reasonable assumptions on the evolution of demand can then be examined on a scenario-basis to assess the impact on the tariffs, the cost allocation and recovery, the duration and the effectiveness of any complementary support.

4.4.3. Network cost estimates

(74) When setting the inter-temporal cost allocation mechanism, estimation of network costs over the duration is needed, e.g. costs of establishing new pipelines or repurpose gas pipelines to hydrogen use. These cost estimates can be highly uncertain especially for repurposed assets where costs of retrofitting may be difficult to project. This results in volatile cost setting which should be mitigated to the extent possible by ensuring proper comparisons between actual and forecast costs, flexibility in cost allocation design, and increasing transparency of estimation including clear distinguishment between new and repurposed assets.

4.4.4. One-off, closed vs flexible approach to network scope

(75) The German inter-temporal cost allocation mechanism is a one-off mechanism that refers only to the approved core-network; no other network elements have the possibility to be included at a later stage. This one-off mechanism, however, is not a necessary or optimal approach for all Member States. Inter-temporal cost allocation mechanisms may be designed in a more flexible way that enables the inclusion of network elements at various stages. The implementation of more than one inter-temporal cost allocation mechanism in the same entry-exit zone, covering different elements of the network, can also not be excluded.

(76) A mechanism that includes a single network, well defined ex-ante, with no option for adding or removing elements in the network scope, is particularly suitable when the network largely reflects the mid- to long-term future market needs. This approach provides certainty to network operators and hydrogen producers and users about their investments and provides a wider clarity on the transmission costs for network users. It also facilitates decisions regarding the duration of the mechanism and the level of tariffs over that period, and it helps identifying the needs for additional state support. On the other hand, extensive networks will normally be designed for longer-term demand, hence they are more susceptible to the uncertainties around the market development and costs[23]. This increased exposure to the market risk may hinder the identification of the necessary level of complementary state

[23] In the absence of binding commitment obligations, hydrogen users are not incentivised to provide accurate estimates about their needs; in fact, they may overestimate their needs or undermine the underlying uncertainties, to ensure they do not miss the chance of being included in the ICA mechanism and the support schemes that potentially complement it.

support and increase the chances of creating inefficient mechanisms based on false estimates about the evolution of the network use and actual costs, potentially resulting in stranded investments.

(77) A more flexible approach in which network elements included in the scope and mechanism are prioritised based on different risk levels and/or their costs, could better align with a more conservative approach towards the hydrogen market development. The development of infrastructure can start with smaller investments where future utilisation is more certain (e.g. network segments where long-term commitments are feasible) and/or relatively low-cost network elements (e.g. repurposed pipelines with small impact on the overall cost of the network). As the market develops, decisions on including more network elements can be taken, based on their expected utilisation profile and estimated uncertainties. A potential disadvantage of the more open approach is that it increases the complexity of the allocation of costs to the network users such as leading to parallel inter-temporal cost allocation mechanism due to several regulatory accounts with separate tariffs and may thus hinder the design of a cost-reflective tariff that is free from cross-subsidies.

4.4.5. <u>Duration of the mechanism</u>

~~(78)~~ The duration of the inter-temporal cost allocation mechanism, i.e. the time over which the costs of the network will be recovered, is a key parameter defining the expected demand over which the costs will be distributed. This impacts directly the estimated tariff level. The duration of the mechanism will normally be defined as the number of years the tariffs of the mechanism are applied. Depreciating assets over their economic lifetime is a best practice. In an inter-temporal cost allocation mechanism other elements need to be considered, like tariff stability, affordable tariff levels, recovery of the initial deficits, and the conditions of any complementary financing scheme. To ensure the most efficient duration of the mechanism and avoid risks of non-cost reflective tariffs and discrimination among users, care should be taken when deciding on the duration and it shall be avoided to set a duration higher than the technical lifetime of the assets. When setting the duration of the mechanism, using different methods for pipelines within a Member State, e.g. between domestic and transit pipelines, may increase risks of discrimination between users which shall be avoided regulatory authorities. Regulatory authorities are advised to consider this aspect.

(79) In the German case, the duration of the mechanisms spans until 2055. Considering that the network will be largely commissioned in the first half of the coming decade, the duration aligns with the expected economic lifetime of the main assets in the core network (estimated at around 35 years). This includes both newly built and repurposed assets commissioned at various stages. The German government has the option to stop the mechanism if the market does not develop in a way that makes the balancing of the amortisation (debt) account probable (see section 3.1). Furthermore, the inter-temporal cost allocation is automatically terminated as soon as the account is balanced, e.g. earlier if the development of cost and demand is better than expected. However, a postponement of the mechanisms after 2055 is not

possible under the current rules. The duration of the Danish mechanism is expected to be specified by the economic lifetime of the assets including any expected re-investments in prolonging the lifetime of repurposed assets. The Danish mechanism is much simpler compared to the German one as it only considers the development of a limited network.

(80) The design of an inter-temporal cost allocation mechanism may allow for some flexibility to adjust the duration in case of significant deviation from initial assumptions on costs and demand. For example, if the demand does not evolve as planned, or actual costs prove to be higher, a prolongation of the cost recovery could be used to maintain the tariff levels. The duration of the mechanism however should normally not have a repayment period exceeding the technical lifetime of the network considering any network (re)investments. Conversely, earlier termination of the mechanism may be desirable once demand expectations have largely materialised, and the market is mature. The mechanism may thus allow to shorten the duration of the mechanism if demand grows faster than initially assumed and initial deficits can be recovered earlier. In all cases, clarity of the flexibility that regulatory authorities will have to adjust the duration of the mechanism, if any, and the details of the process for any adjustment needs to be provided in the decision from the beginning.

4.4.6. Tariff design and setting elements

(81) The inter-temporal cost allocation mechanism is essentially a tariff setting methodology as it defines the level of the tariffs paid by network users to cover the network costs over a long period of time. The Regulation foresees the establishment of a network code setting the rules regarding harmonised tariff structure for access to the hydrogen network. The network code will be established in the future according to the needs of the market. Therefore, any tariff rules set in the inter-temporal cost allocation mechanism should be designed with the awareness and flexibility that it might be affected by a future hydrogen tariff network code. While addressing such topics cannot be likely avoided, it should be minimised to the extent possible.[24]

(82) Based on stakeholders' responses to the public consultation, there is an expectation that an inter-temporal cost allocation mechanism should support the competitiveness of hydrogen supply. Under the assumption of a properly designed, not under-utilised networks, the expected level of the hydrogen transmission costs represents a small fraction of the overall supply cost of hydrogen[25]. Hence, while keeping transmission costs for users at affordable levels would facilitate the market ramp-up, it is not expected that the inter-temporal cost allocation mechanisms can significantly influence the competitiveness of hydrogen at this point. Instead, their

[24] An example could be that any changes to the tariff design improving cost reflectivity such as locational signals i.e., would be limited if the design of an intertemporal cost allocation mechanism imply full revenue recovery by postage stamp tariffs.

[25] In its current position paper ACM however demonstrates that if costs and utilisation of the network vary significantly from initial assumptions the costs may be considerably higher.

main benefit is the avoidance of extremely high tariffs in the early stages of market development, thus to avoid disincentivising or punishing early adopters that are essential for the successful upscale of the hydrogen market. Additionally, while hydrogen transmission tariff levels are unlikely to significantly change the general competitiveness of hydrogen, at least in the short term, they might play a significant role on the competitiveness between production within and outside a Member State. Excessive transmission tariffs could lead to a preference for domestic hydrogen production or isolated hydrogen valleys thus preventing or delaying the development of an EU internal hydrogen market.

(83) As the inter-temporal cost allocation mechanisms aim at providing affordable tariffs to the end users during the ramp up phase, the network users' willingness-to-pay should be considered. The willingness-to-pay relates to the price of the commodity and type of the end user, and is therefore difficult to estimate. Market surveys or assessments based on bottom-up calculations (e.g. comparing the price of hydrogen against its alternatives) could be used to provide insight. Notably, the fact that willingness-to-pay is an essential benchmark does not mean that it should be set as a tariff target a-priori. First, the willingness-to-pay differs between several types of users (e.g. industrial users subject to quotas and power generators). Second, willingness-to-pay may exceed cost-reflective tariffs and setting tariffs at that level will lead to monopoly rents for operators.

(84) The general goal of tariff setting in regulated energy networks is to allocate the costs of the network to the network users in a cost-reflective way. The formula applied for the calculation of the tariffs can be generalised as the division of the allowed or target revenue (the sum of costs related to the transmission activity) by relevant cost driver. Cost drivers may be as simple as the physical or booked capacities, or they may be based on the characteristics of the network like relative distances of network points. Based on the current practices applied in the natural gas sector, both uniform tariff levels (e.g. postage stamp methodologies), or tariffs that reflect the cost differences related to transporting hydrogen to different points of the network using locational signals may be considered. To increase cost-reflectivity and provide incentives towards optimal network development, the application of locational signals could be considered when setting the tariffs for the duration of the inter-temporal cost allocation mechanism. Locational signals may introduce a better allocation of costs between users (or groups of users) increasing cost-reflectivity of tariffs besides the setting of cost elements. This approach, however, may increase the complexity of the mechanism, especially if the network is not fully developed and lead to significant differences between tariffs applied to different users within the same entry exit zone, ultimately outweighing the benefits of the provided cost-reflectivity.

4.4.6.1. Cost elements

(85) Inter-temporal cost allocation mechanism spread the recovery of network investment costs over the duration of the mechanisms through levelised tariffs. The

capital expenses related to the network trivially fall under the scope of these mechanisms[26]. Network tariffs, however, also include the allowed revenue related to the network's operating costs, both fixed and volume dependent. Variable costs are dependent on the actual volumes flown in the network, hence there is no need to spread them over time. The definition of variable costs can include costs related to the physical transport of hydrogen (e.g. costs for compressor stations) and costs of services related to the operation of the network such as balancing and user flexibility. For example, the hydrogen network is expected to be highly under-utilised in the beginning meaning that the network could probably deal with the early imbalances through the available linepack[27]. As demand materializes, the availability of linepack will decrease and balancing costs are also expected to increase. This change over time imposes risk of discrimination if a level-playing field of services offered to the user over time is not ensured. When defining the tariff structure of the mechanism the regulatory authority may consider the application of a volume-based charge for the separate recovery of those volume-based operating costs that should not form the part of the costs falling under the scope of an inter-temporal cost allocation mechanism. When considering the separation of variable operating costs, the regulatory authority should take into account other important criteria such as the predictability of tariffs and relevance of the amount of the variable operating costs compared to the total expenditures.

(86) By way of derogation, article 5(4) of the Regulation allows for financial transfers between regulated services that are separate from each other, provided that the regulatory authority has established that the financing of hydrogen networks through network access tariffs paid only by its network users is not viable[28]. This could for instance be to recover some of the costs from the hydrogen networks from users of the gas transmission network, for example by subsidising operators' revenue on hydrogen infrastructure with tariff increases for domestic gas transmission users. The Regulation[29] has set up a list of conditions that shall apply to financial transfers. In general, financial transfers distort market behaviour and cross-border trade establishing cross-subsidisation between sectors. In the context of decarbonisation, the challenges experienced by both natural gas and electricity network operators (risk of asset stranding due to decreasing demand in one sector, investment pressure due to renewable roll-out in the other) also increase the risks related to cross-sectoral financial transfers. Hence, this measure shall be seen as a matter of

[26] Direct subsidies to capital expenditures are normally deducted from the regulated asset base thus decreasing the network operator's allowed revenues in line with the overarching principle of cost reflectivity (article 17 of Regulation).
[27] Attention to the technical limitations should however be paid and the true capabilities of the linepack during the ramp-up phase need to be carefully assessed on a case-by-case base.
[28] Recital 10 of the Regulation also mentions that "*costs associated with feasibility studies related to the repurposing of natural gas networks to hydrogen networks should not be considered to be cross-subsidies.*".
[29] In accordance with the Regulation article 5(6), ACER may issue a recommendation on financial transfers.

last resort. In most cases aligning network development with demand is a more economically efficient solution.

4.4.6.2. Depreciation

(87) During the determination of the allowed revenue or approved costs, different depreciation models can be considered. Straight-line depreciations provide a fixed value for depreciation to be recovered through the tariffs. Backloaded or other progressive depreciation methods allocate more depreciation to the later periods with larger expected utilisation, acting in themselves as kind of an inter-temporal cost allocation mechanism. Other depreciation methods that result in accelerated and larger values during the early periods of the network's lifetime leading to larger need for an inter-temporal cross-subsidisation. The application of depreciation methods with the purpose of straight-line or back-loaded depreciation decrease the need for further interventions, however these amplify the effects of demand risk and less flexibility, which may lead to liquidity gaps for operators and should therefore be carefully selected and possibly supplemented with fitting risk-mitigation mechanisms.

4.4.6.3. Remuneration with inter-temporal cost allocation

(88) When setting the costs of the infrastructure, the return on the investment is included, normally through the weighted average cost of capital (WACC). This potentially includes any remuneration related to the deficits of the inter-temporal cost allocation regulatory account that are accumulated in the early stages of the ramp-up and need to be recovered in the future (this can be seen as a debt account from the inter-temporal cost allocation and depends on any specific financing support scheme used complementary to the inter-temporal cost allocation mechanism). The level of the remuneration over the inter-temporal cost allocation account should reflect the real risk borne by the HNO over this debt considering any guarantees provided by the state. If the HNO is not exposed to this debt account, no remuneration should be given.

(89) Normally, the capital asset pricing model (CAPM) is used to set a WACC. The CAPM is based on the idea of remunerating systematic risks or non-diversifiable risks for a given investment. Non-systematic risks are not considered in the CAPM as it is assumed diversifiable in a market portfolio, albeit specific cases may occur where non-systematic risks should also be considered.

(90) The future framework for designing an efficient EU internal hydrogen market is yet to be decided. This brings several aspects that regulatory authorities are advised to consider in its decision on remuneration of hydrogen infrastructure.

(91) First, hydrogen is a nascent market with an uncertain future demand. Using an inter-temporal cost allocation mechanism without any fall-back procedures such as state support schemes is an investment with high risks of unrecovered costs.

(92) Second, any remuneration or risk premia needs to reflect actual risks affected by the overall policy and market framework, both at national and EU level. This includes any state initiatives to de-risk investments including any state guarantees to the debt account. Asset beta normally incorporates any market risks.

(93) Third, any reassessments of the inter-temporal cost allocation mechanism should also apply to the WACC-rate as risk-free bonds or risks associated with the investment may change over time. Operators' risk is increasing if WACC-rates are not regularly assessed to fit reality.

(94) Fourth, any financial costs and risks associated with the inter-temporal cost allocation mechanism (e.g. the funding of the initial revenue gap) should be considered as it should not be internalised into the WACC.

4.4.7. Reassessment of key assumptions

(95) Inter-temporal cost allocation mechanisms are based on assumptions on forecasted costs and demand that may be highly uncertain. To ensure the appropriateness of the tariffs calculated based on these assumptions, and the full recovery of costs over the duration of the mechanism, continuous reassessments of the key assumptions including development of the network use are needed. These reassessments are even so relevant if any complementary state support scheme is involved as they can be a mean to control the adequacy and effectiveness of the support scheme.

(96) Both the Danish and German models include regular reassessment of the mechanism to ensure cost recovery over time and provide a cost-reflective tariff for users. In Denmark, DUR is expected to undertake annually or biannually reassessments of the assumptions and will calculate the necessary state subsidy on a yearly basis. In Germany, BNetzA will every three years reassess the level of the ramp-up tariff to ensure cost-reflectivity and the balancing of the inter-temporal cost allocation account at the predefined time while ensuring tariff affordability for the users that may maximize demand.

4.4.8. Potential cross-border trade distortions

(97) The development of the hydrogen market is expected to require interconnections between Member States to facilitate cross-border trade and efficient supply of demand across the EU. While inter-temporal cost allocation mechanisms should be designed to fully recover costs over time, the tariffs derived from the levelisation of costs across the duration of the mechanisms depend on any complementary support schemes, including any guarantees. In this respect, cost-reflectivity is achieved over the duration of the mechanism, but not necessarily at the very short-term.

(98) In this respect, heterogeneous adoption of inter-temporal cost allocation mechanisms across Member States may lead to differences in tariff levels that can poten-

tially lead to incentives for using specific transport routes. Further, with state support schemes for the hydrogen infrastructure, differences in fiscal policies could lead to inefficient competition in an EU internal energy market.

(99) In this context, the potential effects of inter-temporal cost allocation mechanisms on cross-border trade at regional level should be analysed. Enhanced regional cooperation and coordination, as per article 80(1) of the Directive, could help avoid or mitigate any negative impacts. Such coordination should be subject to open discussion and consultation process to enable a transparent process for all stakeholders. In case of cross-border infrastructure, this process could even lead to coordinated decisions across Member States.

(100) Moreover, harmonization on core elements detrimental to efficient cross-border trade should be considered when designing the inter-temporal cost allocation mechanism and general market rules. Such elements may be duration of the mechanism, the recovery of costs over time and projections of cross-border demand.

4.5. Governance of the mechanism

4.5.1. Roles and responsibilities

(101) According to the Regulation it is the Member States prerogative to allow HNOs to recover their cost via an inter-temporal cost allocation mechanism. The inter-temporal cost allocation and the underlying methodology needs to be approved by the regulatory authority. Due to the underpinning uncertainties in the market, the inter-temporal cost allocation mechanisms will most likely be linked to additional State support schemes.

(102) Under article 35 of the Directive, third party access to hydrogen networks shall, in principle, be regulated based on regulated tariffs from 2033 January 1 at the latest. These tariffs or their underlying methodologies shall be approved by the regulatory authority. Inter-temporal cost allocation mechanisms are essentially a method to set network tariffs in the early phase of the hydrogen market development; hence the Regulation calls for the approval of the inter-temporal cost allocation methodologies by the regulatory authorities. Naturally, monitoring of the implementation of the mechanism also falls under the scope of the regulatory authorities' tasks. It is therefore a requirement that prior to the implementation of the inter-temporal cost allocation mechanism the regulatory authorities have been given the necessary powers and resources to accomplish their tasks. Transposition of the Directive into national legislation is hence crucial.

(103) While the design of any potential de-risking scheme is clearly up to the State, its details impact the design and implementation of the inter-temporal cost allocation mechanism. Timely coordination between the entities relevant to the de-risking scheme and the regulatory authorities is therefore important to ensure that the inter-temporal cost allocation mechanism will be developed in a structured and coherent manner. The involvement of regulatory authorities will ensure that the design of the

State support schemes will align well with the general principles for network operation and cost recovery set out in the Hydrogen and Decarbonised Gases Package. Overlapping of roles and responsibilities, e.g. in terms of tariff setting, should be avoided. The interlinkage between the de-risking scheme and the inter-temporal cost allocation mechanism may complicate decision making especially in relation to potential revisions and changes resulting from the actual market developments. Clarity over such decision processes is important to improve implementation. For example, it should be clear in the role allocation whether the regulatory authority can take individual decisions to modify directly some elements of the inter-temporal cost allocation mechanism (like the duration) to accommodate slower market uptake.

(104) It is also recommended that the national network development planning process evolves quickly to align with the requirements of the Package. Oversight of regulatory authorities over the ten-year network development plans, can contribute to improving the analysis by network operators and better link the planning process with cost recovery and market development considerations. While policy targets and aspirations, as reflected in the NECPs, should be considered in the plans, it should be clear what the underlying risks in terms of network development and full cost-recovery mean.

4.5.2. Processes, public consultation and transparency

(105) Given the market uncertainties and the long duration of the inter-temporal cost allocation mechanisms, clear and transparent administrative processes need to be established to ensure regulatory clarity and stability. A clear process plan indicating milestones, roles and responsibilities, and necessary communication of parties involved (e.g. in terms of data transfer) would allow to avoid overlapping processes and to anticipate key decisions (e.g. regarding the revision of the tariffs). Moreover, monitoring of the market developments, network cost evolution and anticipating the network utilisation growth and its potential impact to the costs for network users might indicate the need for changes in the methodology or initiate fall-back procedures. To the extent possible, there needs to be clear and quantifiable triggering elements of these processes (e.g. persistent deviation of actual demand growth from forecasts).

(106) The recurrent tariff calculation and approval process needs to align with the transparency principles set in the Regulation. Cost estimates should be detailed enough to allow effective monitoring of any deviations between forecasted and actual costs. In anticipation of the relevant network codes for hydrogen, the transparency and public consultation provisions of the network code on harmonised transmission tariff structure for gas should be considered as a starting point.

(107) While the inter-temporal cost allocation methodology should be stable over the duration of the mechanism, the tariffs will normally be reviewed regularly. The legal framework for such tariff revisions should be set in a way to safeguard the rights of affected parties, without creating legal uncertainty about the standing of the inter-temporal cost allocation mechanism itself.