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Pipeline Regulation for Hydrogen: Choosing Between Paths and Networks

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Abstract The reliance on hydrogen as an energy carrier, as part of the transition towards a low-carbon economy, will require the development of a dedicated pipeline infrastructure. This deployment will be shaped by regulatory frameworks governing investment and access conditions, ultimately structuring how the commodity is traded. The paper assesses the market design for hydrogen infrastructure, assuming the application of unbundling requirements. For this purpose, it develops a general economic framework for regulating pipeline infrastructure, focusing on asset specificity, market power and access rules. The paper focuses on the scope of application of infrastructure regulation, which can be set to individual pipelines or to entire networks. When treated as entire networks, the infrastructure can provide flexibility to enhance market liquidity. The paper further compares the regulations applied to the US and EU natural gas transport markets. Based on the challenges the EU hydrogen sector faces, including the absence of wholesale concentration and the large infrastructure needs, the paper draws lessons for a regulatory framework establishing the main building blocks of a hydrogen target model. The paper recommends a review of the current EU regulatory framework in the Hydrogen and Decarbonised Gas Package to i) enable the application of regulation to individual pipelines rather than entire networks; ii) enable the use of negotiated third-party access, light-touch regulation and possibly market-based coordination mechanisms for the access to the infrastructure and, iii) allow for a more significant role for long-term capacity contracts to underpin investment.

Keywords Hydrogen infrastructure, Pipeline regulation, Third-party access (TPA), Unbundling, Market design

JEL Classification L95, L51, Q48, Q42, D47

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Pipeline Regulation for Hydrogen: Choosing Between Paths and Networks

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1. Hydrogen in the Energy Transition: Contextualising the Role of Regulation

Decarbonisation has become a global imperative, with governments committing to achieving deep decarbonisation targets in the coming decades.[5] Central to these strategies is the development of low-carbon hydrogen and carbon capture, utilisation, and storage (CCUS) technologies, which are expected to play an important role in mitigating emissions.

While it currently represents less than 0.01 per cent of the global energy mix, hydrogen is considered indispensable for decarbonising hard-to-abate industrial sectors, including steelmaking, chemicals, and heavy-duty transport. Unlike electricity, hydrogen can be stored over long durations and transported efficiently over long distances, offering solutions for seasonal energy balancing and long-haul energy trade. It, therefore, serves as a viable solution for storing intermittent renewable energy. Recent analyses, such as those by the International Energy Agency (IEA), project a nearly fivefold increase in global hydrogen supply by 2050 in a net-zero scenario, with low-emissions hydrogen supply expected to grow by 1500 per cent (IEA, 2022). In these scenarios, hydrogen and its derivatives, including ammonia and methanol, are expected to constitute up to 20-25 per cent of the total energy mix in regions like the EU and the USA by 2050 (IEA, 2022).

In the EU, the European Green Deal, supported by the Fit for 55 Package (European Commission,[6] the Hydrogen Strategy for a Climate-Neutral Europe (European Commission, 2020), and the Industrial Carbon Management Strategy[7] envision hydrogen as a cornerstone of the energy transition, particularly for decarbonising energy-intensive industries and heavy transport. Similarly, the UK's Net Zero Strategy (DESNZ, 2021) emphasises the role of hydrogen (UK Government, 2021) as a low-carbon fuel and prioritises the development of CCUS infrastructure (DESNZ, 2023). The analogue legislation in the US is the Inflation Reduction Act, which provides incentives for carbon capture and storage (CCS) and hydrogen.[8]

1.1. The Broader Systemic Deployment of Hydrogen

Hydrogen occupies a unique position in the energy transition due to its versatility; however, it also faces competition from alternative energy carriers, which allows for the deployment of more competitive solutions.

Hydrogen is expected to play a role in decarbonising sectors where direct electrification is infeasible or inefficient. The highest likelihood of hydrogen use is in energy-intensive

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[5] E.g., the European Union (EU) and the United Kingdom (UK) have pledged to reach net zero GHG emissions by 2050 while Australia has committed to achieve net zero GHG emissions by 2040.

[6] https://www.consilium.europa.eu/en/press/press-releases/2023/04/25/fit-for-55-council-adopts-key-pieces-of-legislation-delivering-on-2030-climate-targets/

[7] https://ec.europa.eu/commission/presscorner/detail/en/ip_24_585

[8] 117th Congress Public Law 169 (Public Law 117-169).

industries such as steel and in processes that can substitute for fossil-based feedstocks such as chemicals, refining and fertilizers.

Sector coupling is central to this vision, where hydrogen enables integration with the power sector and end-use sectors such as industry. Green hydrogen complements electricity systems by absorbing excess renewable generation, reducing curtailment, and providing dispatchable energy in periods of low renewable output. Sector coupling studies have shown how efficient integration can improve congestion. Chyong et al., (2024) provide a review of the literature. Neumann et al. (2023) model the contribution of hydrogen network to Europe's plans to deploy RES generation. The article concludes that a hydrogen network connecting regions with low-cost and abundant renewable potentials to demand centres, electricity production, and cavern storage sites reduces system costs by up to 26 bn/a (3.4%). Although expanding both networks together can achieve the largest cost reductions, by 9.9%

The ability to provide long-duration storage and decouple generation from consumption in time and space complements variable renewable energy. This can reduce the need for extensive overcapacity in electricity grids and offer balancing services at times of scarcity. The flexibility that hydrogen provides is not only technical but also geographic. Hydrogen infrastructure offers an alternative for bulk energy transport from the windiest and sunniest regions in Europe's periphery to low-cost geological storage sites and the industrial clusters in Central Europe with high energy demand but less attractive and more constrained renewable potentials. The system cost benefit of hydrogen infrastrucuture is strongest when the electricity grid is not expanded. However, even with high levels of power grid expansion, the hydrogen network is still a beneficial infrastructure (Neumann et al., 2023)

The potential of hydrogen in maritime and aviation sectors is also being explored, although significant technical and economic barriers remain. Synthetic fuels derived from hydrogen, such as e-kerosene and ammonia, are under development as long-term alternatives to fossil-based aviation and shipping fuels. These applications require substantial investment in hydrogen infrastructure and supply chains, reinforcing the need for a coherent regulatory approach to support these transitions.

Hydrogen can also support rural or peripheral regions where electricity grid upgrades are uneconomical or delayed. Localised hydrogen production and consumption clusters – so-called hydrogen valleys – are emerging as testbeds for technology deployment and regulatory experimentation. These clusters may include a mix of mobility, industry, and residential applications, each with distinct regulatory needs.

The use of hydrogen across end-uses is not without controversy. Criticism points to caution against the widespread use of hydrogen, particularly where alternatives exist, such as in residential heating, light-duty vehicles and others (Argonne National Laboratory, 2020; Chapman et al., 2019; HYPAT, 2022; Johnson et al., 2025). The decarbonisation of district heating systems – a sector historically dependent on natural gas and coal – is largely contested (Agora, 2021; BEUC & ECF, 2021; European Heating

Industry, 2021; Frontier Economics, 2021; Rosenow, 2024). These views temper expectations and call for a disciplined approach to hydrogen deployment based on cost-effectiveness and technological readiness.

The uncertainty over the final uses of hydrogen places significance on the regulatory framework for developing the infrastructure and the support mechanisms for different uses. Decisions based on regulation and central planning to support specific pathways might face limited information, risking the promotion of inefficient solutions which lock in pathways for long investment cycles. The high costs for developing RES in the EU (Agora, 2024; EWI, 2024) can be examples of expensive policy decisions leading to retroactive changes and court appeals (Hancher et al., 2021) . Therefore, a regulatory framework for hydrogen must reflect both the opportunity and the limitations of hydrogen, allowing room for targeted and economically sound deployment based on economic feasibility. The deployment of RES generation in the EU provides relevant experience on the balance of support instruments to to develop technological breakthroughs. Initial subsidies can be justified by the subsequent learning-by-doing spillovers, but should take into account the specificity of production technologies – geographically dispersion and variability, quality resource base and local saturation (D. Newbery, 2018) .

1.2. Characteristics of Hydrogen Production

Understanding the technical and economic characteristics of hydrogen production is essential for designing a regulatory framework that is both feasible and adaptive. Hydrogen can be produced through several methods, each with distinct energy efficiencies, capital costs, and operational expenditures. The most common production pathways are:

- **Steam Methane Reforming (SMR)** is the dominant method globally, using natural gas as feedstock. It has an energy efficiency of 65–75% but results in significant CO_2 emissions unless paired with carbon capture and storage (IEA, 2024).
- **Electrolysis of water is** powered by renewable electricity (green hydrogen) or grid electricity (grey or low-carbon hydrogen, depending on the mix). Alkaline electrolysers achieve efficiencies of 60–75%, while Proton Exchange Membrane (PEM) and Solid Oxide Electrolysers (SOE) offer higher efficiencies (up to 80%) but at higher capital costs (Holladay et al., 2009; Patonia & Poudineh, 2022) .
- **Methane Pyrolysis** is an emerging technology that decomposes methane into hydrogen and solid carbon without emitting CO_2. It offers potential as a low-emission alternative if commercialised and scaled.

The capital expenditure (CAPEX) for electrolysis remains high and have increased in 2023 as a result of inflation. Estimates by the IEA (2024) range from € 1700/kw for alkaline electrolysers to 2150/kw for PEM electrolysers and BNEF (2024) provides a range between € 1700/kw and € 2600/kw in the EU and the US with a lower range in China. TNO (2024) reports higher costs based on actual projects in the Netherlands, which range between € 2630/kw and € 3050/kw. These ranges are further summarised in Table 1. For electrolysers to become cost-competitive with fossil-based alternatives, analysts project CAPEX needs to fall, which requires industrial scaling and standardisation (IRENA, 2020; Krishnan et al., 2023; Patonia & Poudineh, 2022; Roeder et al., 2024).

Table 1: Calculated $LCOH_2$ across studies, including key parameters

Source	Reference Year	Unit capital costs (€/kw_e)	Electricity price (€/MWh_e)	Operating hours	$LCOH_2$
TNO (2024)	2023	3,050	75	4,800	13.69
EU Hydrogen Observatory (2024)	2022	1,250	86	4,120	7.87
Berenschot & TNO (2023)	2023	2,200	50	4,200	12.14
Wood Mackenzie (2023)	2023	1,820	78	4,800	6.72
Umlau & Agora Industry (2023)	2023	1,200	70	4,000	5.98
CE Delft & TNO (2023)	2023	1,710	40	4,300	8.30

The CAPEX of an electrolyser system can encompass the stacks, balance of plants (BOP), power electronics, civil, structural and architecture and utilities & process automation of which the stacks account for a small share of the CAPEX. But system components aside from the stacks, have less potential for cost reduction. Krishnan (2023) assess the potential for cost reduction in stacks were the highest learning potential lies. The study concludes that the total alkaline electrolyser stack costs can be reduced from a range of € 242-388/kW in 2020 to €52-79/kW in 2030. For PEM, this decrease is estimated from a range of € 384-1071/kW in 2020 to 63-234/kW in 2030.

The operational expenditure (OPEX) is primarily driven by electricity input. Its share depends on the operating hours of the electrolysers, the CAPEX and the costs of electricity. As such, electricity prices are the single most influential variable for green hydrogen competitiveness.

The current levelized costs of hydrogen ($LCOH_2$) for hydrogen in the EU vary across technologies and range between € 2.79-4.77/kg for steam methane reforming (SMR) and € 4.13-8.93/kg for renewable hydrogen as reported by the Clean Energy Observatory for 2023. Table 1 provides the $LCOH_2$ across a number of recent studies which range between € 6.72/kg and € 13.69/kg for TNO's estimations in the Netherlands. Additional estimates by the Clean Energy Observatory are provided in Figure 1 and Figure 2 for renewable and SMR hydrogen production.

As of 2024, nearly 99.7% of hydrogen consumed in the EU is fossil-based with renewable hydrogen produced by electrolysis amounting to 22 kt (ACER, 2024). This quantity contrasts with the EU renewable targets for 2030 which foresee 2-4 Mt of renewable and low-carbon hydrogen.

Figure 1: Hydrogen $LCOH_2$ for renewable hydrogen, 2023: Source: European Hydrogen Observatory[9].

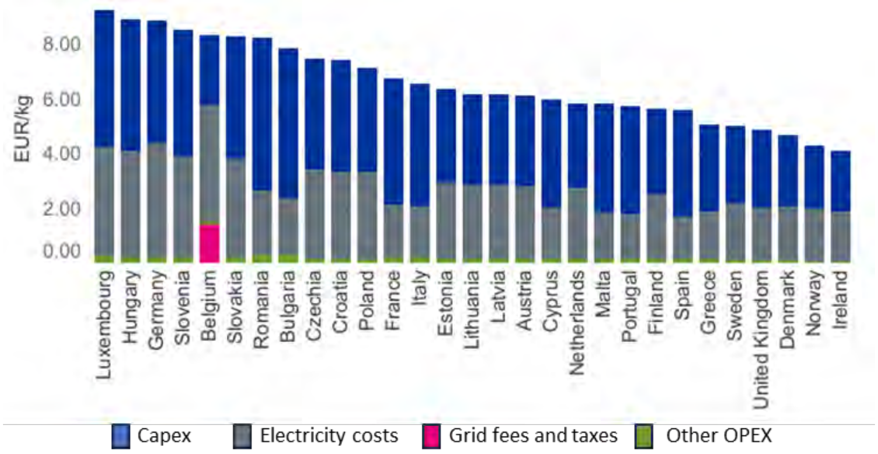
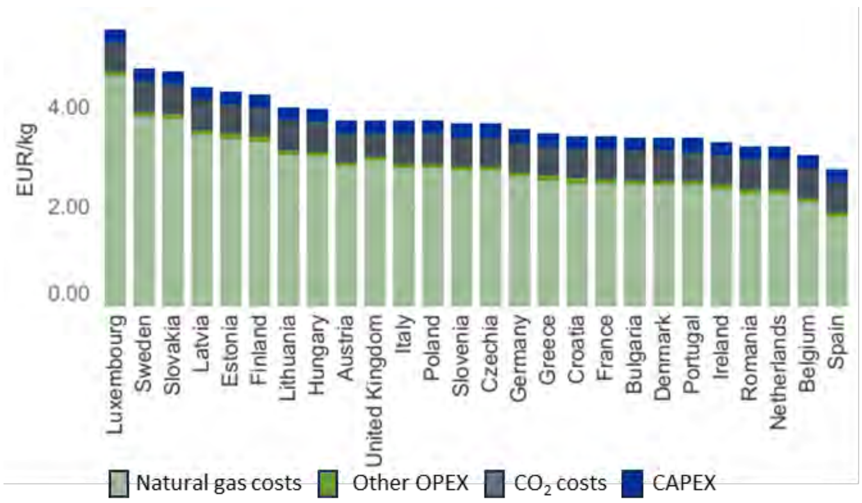


Figure 2: Hydrogen $LCOH_2$ for SMR hydrogen, 2023: Source: European Hydrogen Observatory[10].



Producing renewable hydrogen today is costlier than unabated fossil-based production. This costs gap is increased by the regulatory requirements under RFNBO rules (e.g. hourly time-matching, additionality), which limit the operating hours of electrolysers for production to be labelled as sustainable. This cost premium will impact the competitive of the end-products depending on the share of costs that energy represents and on the capacity to pass-through these costs. The cost disparity highlights the challenge of bridging the gap through policy support, carbon pricing, and innovation, and created large uncertainty about the development of additional demand in new end-uses.

Crucially, hydrogen production does not display natural monopoly characteristics. Hydrogen generation – particularly through modular electrolysis – can be deployed competitively and distributed, unlike large-scale transmission infrastructure. This opens up the market to various actors, including industrial clusters and integrated renewable developers, reducing the rationale for direct economic regulation of production assets, which should be reflected in a regulatory framework for transmission pipelines.

[9] Assumptions used in the calculation can be found here.
[10] Assumptions used in the calculation can be found here.

Regulated decisions over the connection between supply and demand could limit the optimisation resulting from the multiple options to supply end-users.

Furthermore, hydrogen production can be located flexibly. Electrolyser plants are not constrained to resource-fixed sites like natural gas production sites; they can be sited close to renewable energy sources, demand centres, or grid nodes, enabling spatial optimisation based on electricity market signals and infrastructure availability. This flexibility differentiates hydrogen from fossil-based commodities and allows for a more decentralised supply network.

Because electricity costs dominate OPEX, integration with electricity markets is critical. Electrolysers compete for grid access and affect local marginal prices, influencing congestion and redispatch needs. Vom Scheidt and Jyngyi (2022) measure the effects of spatial economic signals when establishing the location of electrolysers in the case of Germany. The latter conclude that hydrogen production increases congestion costs in the German electricity grid by 17%. In contrast, using spatial price signals for electricity leads to electrolysers being placed at low-cost grid nodes and further away from consumption centres. This causes congestion management costs to decrease by up to 20% compared to the benchmark case without hydrogen. Without careful coordination, this can lead to inefficiencies or undermine RES integration. Therefore, regulatory and market design must ensure coherent operation across the power and hydrogen sectors based on accurate investment signals to guide investments.

1.3. EU Hydrogen Policy Outlook

The EU's commitment to hydrogen has evolved rapidly. The 2020 Hydrogen Strategy and the subsequent REPowerEU plan set ambitious targets: 10 Mt of domestic renewable hydrogen production and 10 Mt of imports by 2030. These goals are further reinforced by the Renewable Energy Directive III (RED III), which mandates a 42% share of renewable fuels of non-biological origin (RFNBOs) in industrial hydrogen consumption by 2030.

These targets are supported by a number of policy initiatives which target support and development activities in addition to the commodity, with a view to breaching the competitiveness gap with grey hydrogen, and the development of transport infrastructure. The **EU Taxonomy** firstly identifies hydrogen as sustainable when its life-cycle greenhouse gas emissions are 73.4% below the emissions of grey hydrogen. This enables access to EU financing instruments provided by the European Commission and Member States[11].

The **European Hydrogen Bank (EHB)**, established under the Innovation Fund[12], which aims at bridging the investment gap between supply and demand of renewable hydrogen to achieve the REPowerEU targets. For this, it build on financing mechanisms to support renewable hydrogen production both, within the EU and outside for imports to the EU.

[11] For a summary of these instruments see Annex I of the 2024 ACER Hydrogen Market Monitoring Report (link). The EU Hydrogen Observatory additionally provides a summary of the EU hydrogen funding programs and initiatives (link).
[12] For more information on the EU Innovation Fund visit: link

For the first objective, the EHB used an auction-based mechanism under the EU Innovation Fund. The first auction (IF23 Auction) concluded on February 2024 and aimed at supporting RFNBO production (as defined in the Renewable Energy Directive). Seven renewable hydrogen projects across the EU will receive a total of 720 € million, with a plan to produce 1.58 million tonnes of renewable hydrogen over ten years. The EHB allows this auction mechanism to be used by Member States, with Germany being the first participant enabling €350 million for the Hydrogen Bank auction.

The **H2Global** initiative[13] provides a similar auction mechanism to bridge the gap between higher production costs and willingness to pay on the demand side. On the demand side, projects are in the early stages and there is no willingness to enter into LTCs that support investments in production. H2Global acts as a bankable offtaker to guarantee firm offtake to producers. Hintco is the implementing entity of the H2Global instrument setting up double auctions. Contrary to the EU Joint Purchase Platform[14], which can be extended to hydrogen, and acts as a matchmaker, the resulting contract from the H2Global auctions are signed with H2Global. The mechanism enables long-term purchase agreements with producers while on the demand side they provide investment signals on the short-term which will enable price discovery into the future to develop the market.

There are additional instruments to support the development of infrastructure at EU level. The **Connecting Europe Facility (CEF)** offers funding instruments to projects with a cross-border relevant. The Trans-European Networks for Energy Regulation (TEN-E) sets rules to identify Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI) which include transmission infrastructure, storage and electrolysers with at least 50 MW capacity.

An additional instrument are the **Important Projects of Common European Interest (IPCEI)**. Article 107(3)(b) of the Treaty on the Functioning of the European Union (TFEU), allows to consider state aid as compatible with the promotion and execution of important projects of common European interest or to remedy a serious disturbance in an economy of a Member State. IPCEIs are supported by national budgets and candidate projects are assessed by the European Commission for compliance with the State-aid rules. Up to date, four IPCEIs in the hydrogen value chain have been launched. The four IPCEIs include 99 companies in 16 Member States and Norway including up to €18,9 billion State aid which is expected to unlock more than €27,1 billion of additional private investment[15]. These projects cover support to technology including production, fuel cels storage and transportation (Hy2Tech), the construction of large-scale electrolysers and the integration of hydrgoene in industrial processes (IPCEI Hy2Use), the deployment of lare electrolysers and the repurposing of transport infrastructure (IPCEI Hy2Infra) and mobility application (IPCEI Hy2Move).

[13] For additional information on H2Global visit: link.

[14] For additional information on the EU Energy Platform visit: link.

[15] For additional information of IPCEI projects on hydrogen, visit: link.

In parallel, member states have developed their own **national hydrogen strategies**, aligning to varying degrees with EU objectives[16]. Germany, France, the Netherlands, and Spain have led in project announcements and early regulatory pilots. Although implementation challenges remain, Germany's core hydrogen network proposal and associated cost-allocation rules offer a blueprint for infrastructure expansion.

The plans to develop infrastructure are based on the regulatory framework established in the **Decarbonised Gas and Hydrogen Package**, adopted in April 2024, which creates a common regulatory space for hydrogen transport. The regulation mandates **regulated third-party access (rTPA), based on using an entry-exit network model** and **ownership unbundling,** extending the regulatory framework used in the EU natural gas sector. The regulation further foresees instruments to shift costs across time (i.e. inter-temporal cost allocation mechanism) and to implement cross-subsidies across other sectors (i.e. electricity and gas) as laid out in Article 5. In addition, the regulation foresees the implementation of state guarantees and support to de-risk investments in the early development stages.

1.4. Infrastructure and Regulatory Challenges

Pipeline infrastructure[17] is a critical enabler due to its competitive advantage relative to other modes of transport, in addition to providing access to storage and greater security of supply. This infrastructure is vital for facilitating the large-scale deployment of hydrogen. Institutional settings can be as important as physical infrastructure, and challenges persist concerning developing appropriate regulatory frameworks for deploying and utilising the infrastructure. Furthermore, regulatory design will contribute to shaping the form in which this commodity is traded.

The development of hydrogen pipeline networks presents challenges similar to those faced in natural gas[18] transport markets. The US and the EU offer instructive regulatory models, as discussed in detail in the two case studies analysed in section 3 and section 4 of this paper.

The **US approach** establishes open-access rules for the market to finance long-distance pipeline infrastructure. Transmission pipelines are developed based on long-term contracts (LTCs) that govern the provision of transportation services for point-to-point routes. In comparison, distribution networks feature regulated retail rate settings for some domestic consumers across states. The use of the transmission infrastructure in the short term is not subject to regulation. Instead, it is coordinated by the market through the release of capacity in the secondary market. The US model provides strong signals for private capital, facilitating an efficient and market-based allocation of pipeline

[16] An overview of the national hydrogen strategies can be found in the Annex of the ACER 2024 Hydrogen Market Monitoring: link.

[17] In this paper "pipelines" refers to long-distance pipelines which are subject to regulation or property rights applied individually to each pipeline asset. "Pipeline networks" or simply "networks" refers to a system where multiple pipelines establishing meshed networks are regulated as an single entity.

[18] For simplicity, unless otherwise specified, 'gas' is used to mean natural gas.

capacity. Market parties *compete to gain access to the market* by building new infrastructure capacity to supply demand centres.

In contrast, the **EU model** enables access to infrastructure through regulation applied to entire networks, known as the entry-exit network model (E/E). The service provided by networks extends beyond point-to-point transport, as it grants network users access to virtual trading hubs implemented over the network. In this manner, the infrastructure partially lifts the limitations a point-to-point pipeline transport service imposes on the commodity. The EU model enables regulated network access in the short term, facilitating market competition through established virtual trading points. Investments rely primarily on central planning and coordination between transmission system operators (TSOs), national regulatory authorities (NRAs), European institutions and market parties.

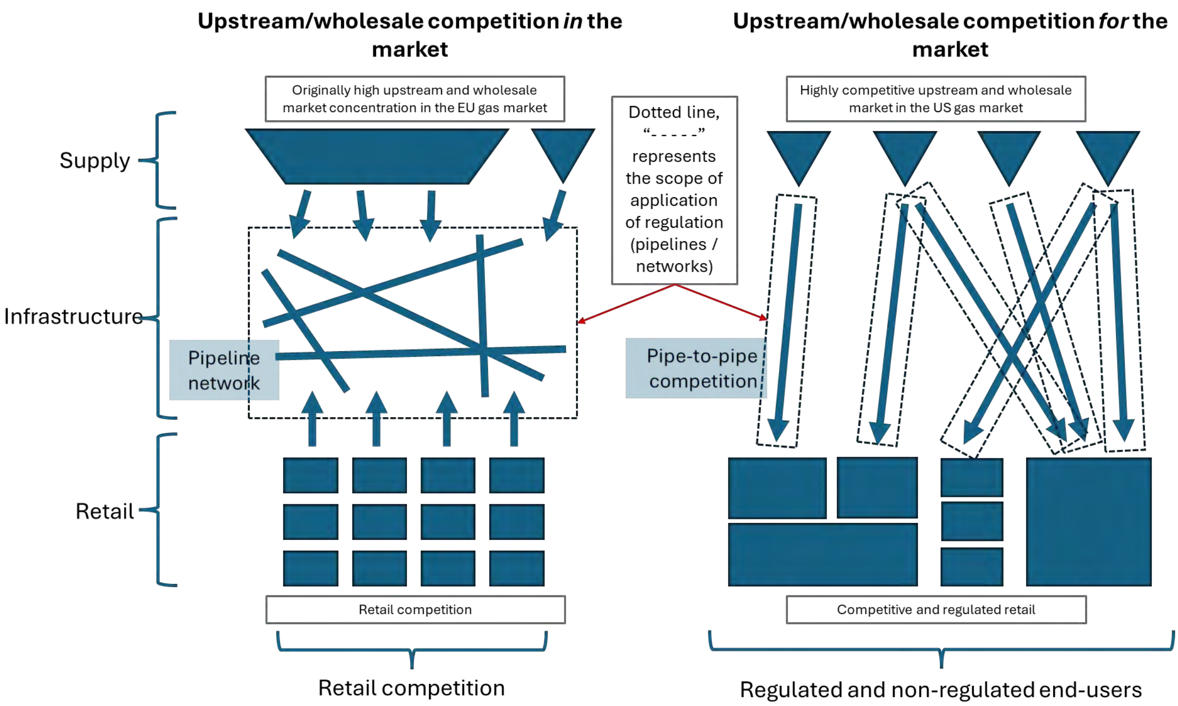
Regulating entire networks also introduces operational flexibility that individual point-to-point pipelines cannot provide. In the EU context, access to network infrastructure includes transportation services and a virtual trading point, enabling what this paper refers to as a 'pooling service.' This service enables market participants to trade gas in the market once they have gained access to the network, regardless of their physical location or the time of day. As a result, the commodity becomes less dependent on specific physical routes, reducing its specificity and further facilitating its standardisation and the enhancement of market liquidity. Treated as networks, the infrastructure enables trading, partly removing the temporal and spatial limitations imposed by point-to-point pipelines.

This paper looks at the regulatory design for natural gas pipelines in the US and EU to draw lessons for hydrogen pipelines. The scope of regulation differs between the EU and US markets. The US market design is based on light-touch regulation applied to individual pipelines. Once primary capacity is allocated, market parties coordinate the use of the infrastructure in the short term. In comparison, the EU market design is based on regulation applied to entire networks, extending TPA requirements to the short term. These rules provide the conditions for offering and pricing pipeline capacity, as well as for balancing. Each regulatory regime is based on different rights for using the infrastructure: long-term contracts in the US and regulation in the EU.

These choices have resulted in two distinct designs in both the EU and the US. Where access is applied at the level of individual assets in LTCs, pipelines compete to provide access to downstream markets; this is the so-called competition *for* the market and enables dynamic efficiency. The commodity is subject to the locational and temporal requirements of buyers and sellers specified in the LTCs underpinning pipeline investments. The parties contracting capacity in the long term bear the risk of incremental capacity.

Where access is applied at the network level, in the form of regulation, market parties compete at virtual trading points enabled by gas networks. The EU approach establishes a network monopoly which enables access to the market. The costs and the risk of financing infrastructure are mostly socialised across all users through network tariffs. The model allows for standardising the commodity and enhancing liquidity. This is the so-called competition *in* the market. Ultimately, the approach limits the possibility of implementing pipe-to-pipe competition and dampens investment signals. This reduces the competition *for* the market (i.e. dynamic efficiency) and requires a central planner to coordinate investments. These two models are represented in Figure 3below.

Figure 3: Design choices for hydrogen pipelines based on US and EU natural gas pipeline regulations.



The article highlights the distinct characteristics expected in the **EU hydrogen market** compared to the EU natural gas market. First, high concentration in the wholesale market is unlikely, which limits the case for extensive TPA regulation in the spirit of the essential facility doctrine. Second, the sector relies more on financing new infrastructure, for which long-term contracts and adequate ownership rights are key. Finally, access barriers limiting liquidity in wholesale markets have not been identified so far, which limits the need to standardise commodity trade by creating monopolies that extend across the entire network.

The case for network-based regulation similar to the EU gas market does not appear fully justified. Developing a sector-based central planning model could lead to significant inefficiencies, including higher costs and, potentially, stranded assets. This conclusion supports the revision of the principles established in the EU Hydrogen and Decarbonised Gas Market package,[19] which extends the regulatory model used to introduce competition in the EU natural gas sector. The US gas market design provides relevant references for regulating EU hydrogen networks, including regulation applied to individual

[19] The Hydrogen and Decarbonised Gas Market package includes Directive (EU) 2024/1788 and Regulation (EU) 2024/1789.

pipelines, more flexible third-party access, and appropriate rights underpinning infrastructure investments.

2. Regulating infrastructure – the case of gas pipelines

2.1. Industry structure and regulatory focus

The natural gas supply chain comprises distinct segments with varying levels of competition. Production can exhibit market structures ranging from perfect competition to single-source supply. In contrast, retail distribution and pipeline transportation exhibit monopolistic tendencies due to high fixed investment costs and low marginal costs, which create significant entry barriers and render duplication inefficient.

Historically, gas markets were vertically integrated, with a single entity managing production, transportation, supply, and retail (Makholm, 2012; Stern, 2012). Starting in the late 20th century, industry deregulation and market liberalisation introduced competition in production, supply, and retail while regulating pipeline transportation to prevent market abuse.

Joskow and Schmalensee (1983) and Newbery (2008) emphasise the importance of separating competitive activities from monopolistic infrastructure to enhance efficiency across the supply chain. In deregulated and liberalised energy markets, regulatory frameworks for natural gas markets reflect this principle, fostering competition in production, supply, and retail while addressing the monopoly characteristics of pipelines.

The separation of competitive activities from the monopolistic infrastructure (pipelines) is established through unbundling requirements. The structural, legal or functional separation of these activities removes the incentives for market abuse, as pipeline operators have no incentive to favour their affiliates or subsidiaries. This facilitates fair competition and creates a level playing field for all market participants. At the same time, it requires designing a regulatory framework for operating natural gas pipelines.

This section presents an economic framework for evaluating regulatory design for pipeline infrastructure in the context of market competition, departing from the application of unbundling requirements. The following four sections explore differentiated blocks determining regulatory frameworks, which relate to:

1. Significant CAPEX costs associated with pipeline investments create a risk of hold-up or opportunistic behaviour. Mitigating this risk requires guarantees for the recovery of investments.
2. Pipeline cost functions range from natural monopoly characteristics to contestable monopoly and pipe-to-pipe competition. These characteristics require the application of regulation to prevent market power.
3. Access to pipeline infrastructure can be based on different requirements and instruments. These range from market coordination to third-party access in its negotiated and regulated forms.
4. Lastly, the scope of application of regulation can be applied to individual pipelines or to the entire network. The paper examines the impact of this choice on the

standardisation of commodity trade. When regulated as networks, pipeline infrastructure can provide flexibility to increase market liquidity.

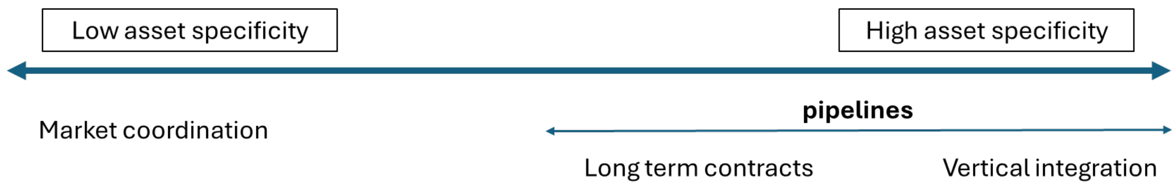
2.2. Asset specificity

Pipelines are characterised by high asset specificity, requiring instruments to mitigate the risk of opportunistic behaviour. Asset specificity refers to the degree to which investments are specialised for a particular use, location, or transaction, making them difficult to repurpose for other applications without significant loss of value. This concept has a significant impact on governance models and regulatory design. Transaction cost economics (Coase, 1937; Joskow, 1985; Klein et al., 1978; Williamson, 1979, 1983, 1985) identifies asset specificity as a key determinant of transaction costs and governance structures. High specificity creates potential hold-up problems, where investors risk *ex-post* opportunistic behaviour, while investments in low-specificity assets can rely on market-driven dynamics.

The risks of hold-up are minimal for assets with low specificity as they can be redeployed or adapted for alternative uses. In these cases, competitive market dynamics naturally guide investment decisions. Investments are typically made through short-term contracts or spot market transactions, with minimal reliance on long-term agreements or vertical integration. This reduces regulatory complexity and fosters market-driven efficiencies. However, as the size of investments grows, along with the duration of payback, asset specificity grows.

For high-specificity assets, tailored mechanisms are necessary to manage risks, ranging from long-term contracts to vertical integration, as illustrated in Figure 4. These agreements, formed during the investment stage, provide financial certainty by ensuring that private parties commit to agreements *ex ante,* thereby reducing uncertainty and opportunistic behaviour *ex post*. This fosters private investment while allowing long-term exclusive use of the transport capacity or its resale for profit. However, the downside is that if the investment underperforms, these parties bear the risks, potentially facing significant financial losses and limited options to recover the sunk investment costs.

Figure 4: Coordination spectrum based on asset specificity.



An alternative governance model for high-specificity assets involves public risk underwriting via guaranteed sunk cost recovery by the state either directly as state-owned enterprises or through regulation.[20] This approach is rooted in the public good theory (Musgrave, 1959; Samuelson, 1954; Stiglitz & Rosengard, 2000), which supports

[20] For an in-depth analysis of the history of ownership and regulation, privatisation, and theories of regulation, see Newbery (2000).

government intervention for nonrival and nonexcludable investments. The entire network is a highly specific asset, providing the only economical way to deliver gas. As the network becomes increasingly dense, any single pipeline becomes less specific due to the availability of plausible substitutes. This subtlety defines the tension surrounding pipeline governance: while networks, as a whole, may be considered a monopoly, individual pipelines within these networks become competitive substitutes, opening the possibility for pipe-to-pipe competition. If the network is dense enough and shippers can use alternative routes, the market power of any given pipeline can be mitigated. More broadly, where the distribution of upstream production allows for competition between producers to supply demand points, competition between pipelines to transport gas is feasible.

Governments underwrite investment risks through regulatory tools, such as network access regulations, which guarantee non-discriminatory access and ensure cost recovery through tariffs or auctions. This model prioritises inclusivity and social benefit but requires robust oversight and reduces private investment incentives. The costs of investments are socialised, even when they are proven inefficient. At the same time, benefits such as the provision of essential services, enhanced energy security, and market competition are also distributed across society.

2.1. Market power under natural and contested monopolies

Pipelines have a natural monopoly cost function that is contestable under certain circumstances. At one extreme, there are pure natural monopolies, such as distribution pipelines connecting every household to central supply points. These pipelines (or networks) exhibit high fixed costs and economies of scale, making duplication inefficient. Natural monopoly theory (on the origin of the concept of natural monopoly, see discussion in Mosca (2008)) justifies government intervention to regulate pricing, ensure fair access, and guarantee recovery of sunk costs. Governments typically regulate these pipeline networks by mandating universal service obligations and applying stringent pricing oversight that allows for cost recovery. This regulatory approach ensures equitable infrastructure services but can reduce private investment incentives due to heavy public oversight.

A natural monopoly arises when a single firm can supply a good or service at a lower cost than multiple competing firms due to economies of scale. This is the result of the relationship between the perimeter and the volume of the pipeline. While the former increases multiplicatively, the latter increases exponentially. The capacity increases at a greater rate than the costs as pipelines increase in size (El-Shiekh, 2013; Parker, 2004). This subadditivity of costs underpins the classification of pipelines as natural monopolies (Baumol, 1977; Berg & Tsichirhart, 1988; Joskow, 2007). Subadditivity occurs when the total cost of providing a service is lower under a single provider than it would be if multiple providers were to compete. Empirical studies demonstrate that economies of scale exist for the cases analysed (Brown et al., 2022; Gordon et al., 2003; Massol, 2011; Penev et al., 2019; Perrotton & Massol, 2018).

A static view of natural monopoly assumes persistent economies of scale, but dynamic considerations reveal complexities that challenge these assumptions. While most pipelines exhibit economies of scale, some (limited) evidence suggests that long-distance, large-capacity pipelines may experience constant or even decreasing economies of scale (Oliver, 2015) .[21] This finding aligns with the notion that transaction costs gain importance as output expands, and average cost curves for any firm are likely to be U-shaped (Cole & Grossman, 2003).

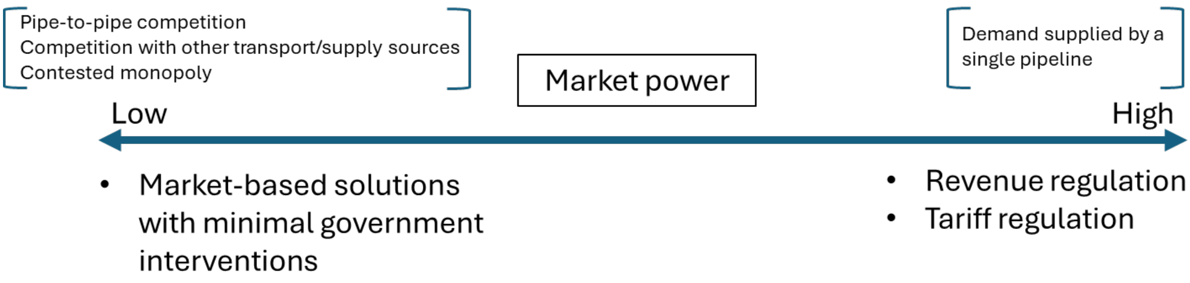
Makholm (2012) critiques the static natural monopoly framework, noting that geography, geology, and political factors often render pipelines obsolete well before the end of their depreciation timeline. Thus, pipelines, especially long-distance, high-pressure lines with natural monopolistic characteristics, may operate only during specific market conditions. Over time, technological advances, shifting market conditions, and politics can reduce their natural monopoly characteristics, creating the potential for competition. Makholm highlights that 'gas pipelines face persistent threats of rivalry' and that 'the scale economies evident in pipeline cost structures dominate only if governments, or their regulators, allow it to happen' (Makholm, 2012, p. 44).

Depending on how pipelines are developed and regulated, the cost function of natural gas pipelines might not have natural monopoly characteristics. The monopoly status of pipelines can be challenged, either by competition with other monopolistic infrastructure or by the contestability of the monopoly itself. This dynamic perspective emphasises that regulatory interventions must adapt to market, technological, and political dynamics, avoiding policies that unnecessarily entrench monopoly characteristics. The theory of contestable markets (Bailey & Baumol, 1984; Baumol et al., 1982; Demsetz, 1968) highlights the importance of enabling market entry and ensuring competitive pressures even in monopolistic markets. Dynamic considerations, thus, highlight the need for regulatory frameworks to (i) account for changing market and political dynamics and resource distribution, (ii) adapt to technological advancements, and (iii) encourage competitive dynamics where feasible, balancing cost recovery with market contestability.

Depending on the extent to which pipeline monopolies are contested or face competition from other gas sources or pipelines, different instruments can be used to address market power. Where pipelines are not in competition, revenue regulation such as rate-of-return or price-cap regulation can be applied. Where pipelines are in competition, or their monopoly characteristics are contested, market power is limited and can be addressed by instruments closer to market-based solutions. This spectrum is summarised in Figure 5 below.

[21] Although Oliver (2015) argues that the demand for such pipelines is often insufficient to justify their economic feasibility, and shorter, incrementally expanded pipelines may be more efficient due to smaller price spreads between supply and demand centres.

Figure 5: Regulatory instruments to address pipeline market power.



Rate-of-return regulation is a longstanding regulatory instrument that ensures operators recover costs while earning a reasonable return on investment. Its origins can be traced back to US Supreme Court rulings, such as Smyth v. Ames (1898), which established the principle of fair returns based on asset valuation, and Hope Natural Gas Co. v. Federal Power Commission (1944), which emphasised balancing investor and consumer interests. Early economic contributions, such as those by Hotelling (1938), provided theoretical support for regulating monopolistic pricing in public utilities. Later critiques, including Averch and Johnson (1962), demonstrate the potential for overinvestment under rate-of-return regulation, highlighting its unintended effects on capital allocation.

Price-cap regulation is a form of incentive-based regulation introduced by Littlechild (1983) to improve efficiency and reduce costs while maintaining service quality. Unlike rate-of-return regulation, price-cap regulation decouples a firm's revenue from its actual costs, incentivising cost-saving measures and innovation. The regulated firm can set prices to a predetermined cap, typically adjusted periodically using a formula that accounts for inflation and an efficiency factor (RPI-X). This approach encourages productivity gains and cost reductions by allowing firms to retain profits from efficiency improvements during the regulatory period. Joskow (2014) discusses its application in electricity distribution and transmission networks, exploring its theoretical foundations and practical implementation.

While the application of revenue and tariff regulation is widespread in the EU, examples of pipe-to-pipe competition exist and have been discussed in the literature (Hirschhausen et al., 2010; Knieps, 2002; Lapuerta & Moselle, 1999; Moselle & Harris, 2007). In particular, negotiated access to competing pipelines was applied in Germany, although with limited success given the concentration in the market (Lohman, 2006). The BBL and the Interconnector Limited pipelines are additional examples of competition between pipelines and other infrastructure in the EU (such as storage, LNG import terminals and interconnection points).[22]

[22] These pipelines are exempted and derogated respectively from the application of EU regulation on allowed revenue and tariffs. For Interconnector Ltd, the derogations were provided by Ofgem (link) and by CREG, the latter assessed by ACER (link). For BBL, the exemption granted by Ofgem and ACM are referred in the 2019 ACER tariff report (link).

In the case of the US, the regulatory regime applied by FERC assumes that pipelines have market power. For this reason, open seasons used to allocate capacity in the long term are based on a fall-back regulated price cap, which allows parties to negotiate tariffs, as discussed in Section 3.3. At the same time, Orders 436 and 636 foresee the option to apply market-based rates to pipelines following an HH1 test proving the absence of market power.[23] This approach has only been applied to a single inter-state pipeline (the Rendezvous pipeline),[24] highlighting the exceptionality of pipelines that lack market power. The US regime acknowledges that there are natural monopoly elements that justify regulated transport rates, which can differ based on specific demand (expressed through open seasons) and on the costs of particular routes. At the same time, the design relies heavily on the ability to use different routes to mitigate the underlying market power. Market power is mitigated through competition between pipelines, which provides producers with access to markets. Market dominance at given nodes signals a long-term incentive to invest in additional pipeline capacity.

2.1. Access rules: balancing market coordination and regulation

The need to define pipeline access rules can be approached from the perspective of common-pool resources. Using this framework, the section introduces the various access regimes applicable to pipelines and examines the options for applying access rules to individual pipelines or entire networks.

2.1.1. Pipeline infrastructure as a common-pool resource

Pipelines can be considered a common-pool resource, as discussed by Ostrom and Hess (Ostrom & Hess, 2010), which assumes that the infrastructure is a non-excludable good that alternates between rival and non-rival characteristics, depending on whether there is limited capacity or over-capacity, respectively. Pipeline infrastructure shares characteristics with both private and public goods, in that although public goods are non-excludable, they do not presuppose rivalry, while at the same time, private goods are excludable. Pipeline access rules establish conditions for using infrastructure where rivalry and non-excludability are granted.

Non-rivalry in the context of natural gas infrastructure occurs when the withdrawal of one unit from the network does not reduce the network's available capacity over a specified period. This situation applies in the absence of congestion, where there is over-capacity in the system. In such cases, one user's decision does not impact the rest of the users. However, where congestion is possible or frequent, the decisions by one user does impact the rest of the users. As a result, non-rivalry tends to be weaker where capacity is limited, i.e., where congestion occurs. Providing access in such conditions requires defining access rules.

Non-excludability is based on the fact that access to pipeline infrastructure is usually a 'naturally' excludable good. It is not difficult to exclude individuals from using them (this

[23] FERC routinely approves requests for market-based rates for storage but not for transportation.
[24] See FERC's 7/27/05 Order for further consideration Rendezvous Gas Services LLC under CP05-40 et al. (link).

is clear in the case of congestion). However, restructuring network industries implies opening access to pipeline infrastructure. Open access (i.e. non-excludability) is the consequence of a conscious public policy that guarantees access to the use of a resource (Ostrom & Hess, 2010). Although the meaning of 'open access' is quite diverse, all regimes share the requirement of removing the right of the infrastructure owner to discriminate against certain users; this is often referred to as third-party access (TPA) – all forms of open access aim to increase the costs of excluding users from the network.

2.1.2. Third-party access

Access rules establish the conditions for to the use of the infrastructure, ensuring competition in the market. If access is denied or granted on discriminatory terms, the users of the infrastructure (or the owners of the infrastructure where unbundling requirements do not apply) can leverage their market power to exclude competitors or extract monopoly rents. This principle has been widely applied in gas transmission (D. M. Newbery, 2000), electricity networks (Joskow & Tirole, 2000), and telecommunications (Laffont & Tirole, 2001).

Access rules can be implemented ex-ante, with predefined regulatory frameworks, or ex-post, through competition law enforcement. Ex ante regulation (e.g., third-party access, open access) is preferred where the risk of foreclosure is high (Armstrong & Sappington, 2006). Ex-post competition law enforcement, applied with market-based mechanisms or with more lightly negotiated TPA regulation, is used where market failures are less pronounced and regulatory intervention risks distorting investment incentives (Motta, 2004).

TPA encompasses requirements and mechanisms that extend from basic non-discriminatory conditions to more complex and detailed rules on the use of infrastructure, including tariffs, capacity allocation, balancing, and congestion management. TPA aims to ensure non-discriminatory access for all market participants, and it has been a critical component of broader deregulation and liberalisation efforts to dismantle previously vertically-integrated market structures.

TPA can be implemented in two primary forms: regulated TPA and negotiated TPA, which differ in the conditions required for access to the network. Under regulated TPA, the terms for accessing the networks, including tariffs, are set by the regulatory authority and are binding for all parties. In negotiated TPA, access terms, including tariffs, are agreed upon through direct negotiations between the network owner and the third-party user. A negotiated TPA is an obligation to offer services on a non-discriminatory basis. In contrast, a regulated TPA is a requirement to regulate the services provided by pipelines based on non-discriminatory rules.

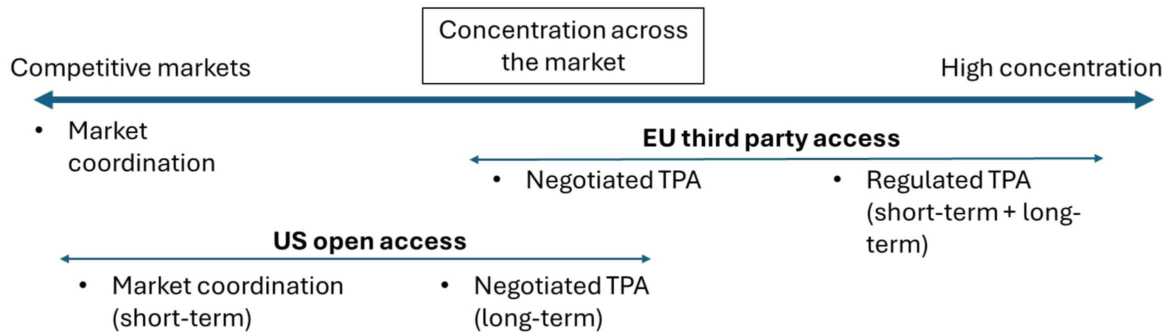
Regulated TPA is the predominant model in the EU gas sector, favoured for its effectiveness in ensuring fairness and transparency in network access. It implicitly recognises pipelines as natural monopolies by mandating non-discriminatory access to infrastructure deemed essential for competition (Joskow, 2007; Talus, 2011a). This framework aligns with the 'essential facilities principle', which identifies networks as critical resources for market competition requiring regulatory oversight to prevent market exclusion (D. M. Newbery, 2008). When a monopolistic infrastructure is indispensable for competition in a related market, access must be provided under regulated conditions (Baumol, 1982; Economides & White, 1995).

From a welfare economics perspective, TPA fosters competition by reducing barriers to entry, improving allocative efficiency, and enhancing liquidity in wholesale gas markets (Glachant, 2010). However, it also raises concerns regarding investment incentives, as mandatory access rules may reduce the expected returns on new pipeline infrastructure, leading to potential underinvestment (Tirole, 1988). The tension between ensuring access and maintaining investment incentives remains a key regulatory challenge in EU and US gas markets.

The application of negotiated TPA is not foreseen in the current EU regulation applicable to natural gas (Regulation (EU) 2024/1789) nor in the Third Package; however, it was allowed by the first Gas Directive (Directive 98/30/EC), and was implemented in Germany to enable pipe-to-pipe competition.

Depending on the degree of competition in the market and the distribution of production across the territory, access rules can shift between partial or full market coordination and regulated TPA in both the short and long term. Intermediate instruments include negotiated TPA and hybrid forms, which can combine TPA in the long term and market coordination in the short term. These instruments are summarised in Figure 6 below.

Figure 6: Regulatory tools for natural monopolies and quasi-natural monopolies



In the US, access to pipelines is based on open access, which differentiates the requirements for long-term financing of new pipelines from those for short-term access. A hybrid TPA regime is applied to open seasons for new capacity, combining regulated rates with the obligation to offer services in a non-discriminatory manner during the open season. At the same time, the use of the pipeline infrastructure in the short term is coordinated by the market, so there is no TPA regulation in this market window. This approach is possible due to the lower specificity of natural gas pipelines and the high levels of competition in the upstream and wholesale markets.

In the case of the EU, access to the network is based on regulated TPA requirements that apply to both the short term and long term. The introduction of stringent access regulation was justified based on the essential facility doctrine, whereby access to the network was deemed essential for the liberalisation of concentrated upstream and wholesale sectors.

It should be noted that the implementation of access regimes is tightly connected to the type of rights provided for the use of the infrastructure. In other words, access regimes are implemented at the level of the rights granted for the use of the infrastructure. These rights can be property rights (e.g. US) or regulation (e.g. EU). In the case of the US, access is established as the obligation to offer capacity on open seasons for long-term transport capacity contracts, which are negotiated. In the case of the EU, access is established through regulation to use network infrastructure, with regulated access applicable across all timeframes. The choice of access regimes is, therefore, a choice of the rights granted for the use of the infrastructure.

2.2. Scope for application of regulation: impact on commodity trade

The scope of application of the regulation to individual pipelines or to entire networks is directly related to the type of service provided by this infrastructure, which subsequently impacts the specificity of the commodity. The regulation of infrastructure in network industries – such as natural gas, electricity, and telecommunications – significantly influences the market dynamics and economic characteristics of the commodities transported. Unlike standard goods, commodities in network industries are subject to physical, spatial, and temporal constraints, which influence how regulation affects their pricing, liquidity, and competition. Regulatory interventions targeting network infrastructure – including access rules, tariff structures, and investment incentives – can significantly alter the contestability, standardisation, and economic efficiency of commodity markets (Glachant et al., 2013; D. M. Newbery, 2000).

Unlike electricity and telecommunication networks, pipeline paths can be contracted on a point-to-point basis (Makholm, 2012, p. 37). In electricity networks, the inability to predictably trace electrons prevents the creation of physical contract paths for electricity sales (Hogan, 1992). This decouples the sale of electricity from the individual lines that transport the commodity, supporting the creation of electricity or power 'pools' managed by pooled transmission operators, where power is sold. In the case of gas pipelines, the flow of gas is predictable from point to point and accommodates physical contract paths. The decision to regulate individual pipelines or entire networks is, therefore, not determined by the physical characteristics of the pipeline infrastructure but is, instead, a design choice.

In network industries, the commodity and the infrastructure are complementary, meaning access to transportation or transmission networks is a prerequisite for commodity trade. In the case of natural gas and electricity markets, TPA regulation forces infrastructure owners to offer non-discriminatory access to competing market participants, transforming previously vertically-integrated monopolies into multi-operator markets (Joskow, 2005). This shift enhances the liquidity of the commodity, particularly when combined with market-based mechanisms such as entry–exit pricing models in gas transmission or locational marginal pricing (LMP) in electricity (Cramton et al., 2013).

Traditionally, pipelines have been used to transport gas from one point to another. However, in the form of networks, pipelines can provide flexibility to facilitate trade. This paper refers to this service as ‘pooling’. While pipelines can provide a point-to-point transport service when regulated individually, providing flexibility in the form of pools requires applying regulation at the network level.

2.2.1. Commodity standardisation and network flexibility

This paper approaches commodity specificity as a design variable in the regulatory framework applicable to pipeline infrastructure. This approach explains the diversity of natural gas institutional designs that can be motivated not only by the degree of contestability or market power for pipeline infrastructure but also, more broadly, by the impact of regulation on the specificity of commodity trade (Hallack & Vazquez, 2014).

Natural gas trade over pipelines is subject to locational and temporal constraints imposed by the pipeline infrastructure. Consequently, the natural gas trade reflects these constraints, which render the commodity highly specific, further limiting the number of eligible parties to trade and, hence, market liquidity. To overcome this limitation, market parties can agree on delivery terms, which they outline in LTCs. Alternatively, a network of pipelines can be designed to provide sufficient flexibility to overcome the limitations imposed by point-to-point pipelines (Vazquez et al., 2012b). Under the latter approach, pipelines are regulated as entire networks, allowing for standardising commodity specifications for trading gas. Any gas in the network can be traded, regardless of its location within the network and the time frame (e.g., daily). The commodity evolves from being location- and time-specific to a fully fungible traded asset. The design has been referred to as a commercial model, and it is based on the socialisation of zonal flexibility to overcome the limitation of point-to-point pipeline transport (Vazquez et al., 2012b). As a result, the commodity’s specificity decreases significantly, facilitating market liquidity and reducing the need for more specific LTCs.

From the commodity perspective, the choice to regulate entire networks is primarily driven by the objective of standardising trade, removing its locational specificity. However, this approach results in a loss of performance for the pipeline-provided service. As argued in sections 4.3 and 4.4, the homogenisation of a commodity dampens investment signals, creating a need for a central planner and the socialisation of investment risks. In addition, the treatment of entire network monopolies can hinder the cost-reflectivity of tariffs, which are decoupled from the costs of the underlying pipeline assets. Finally, this approach can reinforce localised market power despite regulatory efforts to promote competition (i.e. infra-marginal rents resulting from tariffs to recover network costs, the so called tariff ‘pancaking’).

The move from pipeline to network access reduces the firmness of the rights to use the infrastructure, impacting its bankability. While capacity and tariffs for point-to-point pipelines can be offered long-term, the network access rights are only optimised in the short term.

3. US regulation for natural gas pipelines

The following section provides an overview of the market design of US natural gas pipelines. First, it presents the fundamentals of supply and demand regarding domestic production, which have primarily impacted regulatory design compared to the EU gas sector. It then explains how the regulation of natural gas pipelines has evolved up to the liberalisation of the sector in the 1980s and 1990s. Finally, the section describes the market coordination for the short-term use of pipelines and the regulatory instruments for financing new capacity based on open access conditions.

3.1. Supply and demand fundamentals

The US has about 3.5 million kilometres of gas pipelines, with about 500,000 kilometres in the crucial long-distance transmission category (AGA). These trunk lines connect producing and consuming regions, are subject to federal oversight by FERC, and are the focus of the analysis in this section. Other parts of the US system, upstream gathering[25] and downstream distribution, are generally regulated at the state level. While standards are aligned across states and parts of the supply chain, state regulatory oversight is not monolithic.

The US has long been a important producer of natural gas, which has significantly influenced the development of the pipeline sector. Historically, production was concentrated in regions such as the Southern Plains; however, production is now more geographically dispersed. The physical characteristics of produced gas vary substantially across regions, primarily due to the presence of petroleum and natural gas liquids, but after field processing, gas transported in long-distance pipelines is homogeneous and differs only slightly between pipelines. [26]

Investment in new productive capacity is variable, depending heavily on price expectations. Both associated and non-associated gas are essential to US production, including recent advances in shale production. Some shale production regions are dominated by gas (e.g., the Marcellus), while others are more akin to conventional associated gas (e.g., the Permian, Bakken). The co-production of oil and gas has enabled the competitive market structure of petroleum to spill over into natural gas production. Producers accustomed to selling crude oil to refineries under competitive conditions sought similar outlets for gas. The large number of producers and low concentration of output has contributed to the competitive environment in gas production.

US gas demand is divided between relatively inelastic but seasonal residential and commercial demands, a larger and more price-responsive industrial demand, and demand for electric power generation that has been growing steadily in recent decades.

[25] These are upstream pipelines that are often private carriage but, in some cases, are regulated pipelines (e.g., when systems cross state lines or operate on federal land). They are used for moving gas from wells to processing.

[26] The primary differences are varying amounts of ethane that remain in the gas stream. Because ethane has a higher heat content than methane, so-called “ethane rejection” has the net effect of increasing the heat content of the product.

In many markets, the demand for electric power is counter seasonal. Transportation demand is relatively small compared to these other categories. More importantly, the mechanism for delivery is through local distribution companies (LDCs), which are typically state-regulated, geographic monopolies with an obligation to serve. Some industrial and power demand is satisfied directly in wholesale markets, but LDCs are the primary suppliers to residential and commercial users, accounting for approximately 90 per cent of supply. Approximately half of industrial and 75 per cent of electric power demand are satisfied without an LDC or municipal utility being involved, meaning that about half of total consumption is transacted at wholesale prices rather than retail levels. This enables a more significant number and greater variety of buyers in the wholesale market, with a corresponding impact on the transportation market.

The US market is closely integrated with Canada and, increasingly, Mexico via pipeline links. There are also growing connections to global markets through LNG. Gas is delivered to thousands of locations and sold at hundreds of physical trading points distributed across the country, with the Henry Hub[27] in Louisiana being the most liquid. Hubs provide pricing signals that are used as the basis for indexed contracts and a robust architecture of derivatives offers risk management tools to suppliers and buyers alike.

3.2. Regulatory history of the US natural gas sector

The section provides an overview of the evolution of US regulation for pipelines. For this purpose, the section draws on the concepts described in the theoretical framework in Section 2. This section describes the evolution of US regulation, including the departure point for liberalisation after the use of wellhead regulation and the process leading to the unbundling requirement for this infrastructure. The section further refers to the impact on specific natural gas pipelines, which was an essential factor in enabling market coordination following Order 636 and the final departure from the previous regulation.

The initial production and consumption of gas was very local, often relying on 'town gas' or 'coal gas' as a municipal fuel source. Systems were built in dozens of US cities in the 19th century, typically distributing manufactured gas within a relatively small geographic area (Bradley, 1996). Over time, supply chains expanded to leverage natural gas deposits, particularly those linked to petroleum production. The US natural gas sector developed around vertically integrated firms that controlled both production and delivery, often structured as utility holding companies, allowing suppliers to exert market power in downstream markets.

Two crucial early regulatory developments were the separation of transmission and distribution services through the Public Utility Holding Company Act (PUHCA) of 1935

[27] Henry Hub, situated in Erath, Louisiana, serves as a physical delivery point for natural gas in the United States. It functions as a nexus of multiple interstate and intrastate pipelines, facilitating the physical receipt and delivery of natural gas. This infrastructure enables natural gas shippers and marketers to access pipelines serving markets across the entire US. In contrast, many European natural gas markets operate through virtual trading points (VTPs), which are non-physical hubs facilitating gas trading without the need for booking transmission capacity.

and the regulation of existing transmission pipeline rates through the Natural Gas Act (NGA) in 1938. The intent was to break up the integrated industry, much as had been done earlier with railroads and petroleum. The NGA turned away from the common carrier[28] model that had served well in the case of oil pipelines, opting instead for a direct, regulated rate model that placed limits on the scope of activities pipeline operators could engage in (Makholm, 2012, Chapter 6). The common carrier model treated pipelines like natural monopoly utilities rather than transportation service providers. Interstate pipelines were treated like large distribution networks, which were regulated at the state level. One result was that few pipelines invested in their own production, relying instead on the relatively large number of producers to source supplies. With the expansion of oversight to new pipelines in 1942, a second result was that regulatory approval was required for the construction of new pipelines.

Regulatory oversight expanded in 1954 when the Federal Power Commission (FPC, the precursor to the Federal Energy Regulatory Commission or FERC) introduced wellhead price regulation in response to a Supreme Court decision interpreting the Natural Gas Act (NGA) as applicable to all producers selling gas interstate, not just interstate pipelines.[29] The FPC employed a cost-of-service approach that was suitable for interstate pipelines but failed to capture the relevant scarcities associated with lumpy investments in new wells. Regulating prices at the wellhead distorted investment incentives, even after the FPC adjusted the scheme for geographic pricing. Ultimately, the approach led to demand substantially outstripping supply for interstate gas. Producers often preferred to sell in unregulated intrastate markets.

Even after wellhead price regulation was imposed, interstate pipeline companies could effectively bundle the commodity and transportation aspects of the trade. They procured supplies upstream at controlled wellhead prices (i.e., subject to a price cap) and sold the gas downstream, internalising the transportation costs in the sales prices. This structure allowed for the exerting of market power, which influenced the delivered price. Substantial asset specificity in routes persisted, particularly with the FPC granting or withholding approval for competing pipelines. Treating gas transportation as a public utility was initially considered sufficient to ensure continuing service. Over time, the shortcomings of this view became apparent and eventually led to efforts to liberalise the market.

Wellhead price controls were the highwater mark for the economic regulation of US gas. The shortages that price controls helped cause during the 1970s helped catalyse an attitude that market excesses were preferable to regulatory failures.[30] From 1978

[28] A common carrier is a pipeline company that transports natural gas for the general public and is obligated to provide non-discriminatory service to any customer under standardized rates and terms. A private carrier, in contrast, transports natural gas exclusively for specific clients based on individualized contracts and is not obligated to serve the general public. These carriers have greater flexibility in selecting customers and negotiating terms without the extensive regulatory requirements imposed on common carriers.
[29] Phillips Petroleum Co. v. Wisconsin 347 U.S. 672 (1954)
[30] See chapter 3 of MacAvoy and Pindyck (1975) for a contemporaneous discussion illustrating that greater market orientation was not a foregone conclusion for the US market.

onwards, a steady progression toward coordination through prices and contracts, rather than regulation, has transformed the US gas market. Through several stages described below, the result has been a deregulated, but not completely unregulated, system that shows greater integration across regions. The starting point for liberalisation differed from that of the EU. While the EU departed from the need to remove market power grounded in LTCs, the US departed from the adverse effects of wellhead regulation. As purveyors of the delivered commodity, pipelines could no longer procure sufficient gas to meet downstream demand, and LDCs were eventually forced to curtail gas sales to end-use consumers; over the period 1968-1977, the estimated net loss in the US market was roughly $20 billion, measured at 1982 prices (MacAvoy, 2000; Oliver & Mason, 2018, p. 239). In conjunction with long-term take-or-pay agreements between producers and pipelines, shortages led to pipelines being contractually obliged to buy gas they could not sell (Masten & Crocker, 1985). To continue delivering gas, a new framework was needed that moved away from the unintended costs of regulation. This contrasts with the EU, where regulation focuses on corralling national energy companies' market power.

The 1978 Natural Gas Policy Act (NGPA) phased out wellhead price controls for production from new wells.[31] Recognising that interstate and intrastate gas operated in different markets, the NGPA also began to allow shippers to use interstate pipelines that would have previously been off-limits. With approval from the newly-created FERC, end users could procure their supplies – often at higher prices intended to promote the production of new supplies – and then pay pipelines to transport them on a merchant basis.[32] While this nudged the market away from regulation, it did not have as dramatic an effect on pipelines as the elimination of wellhead pricing had on the production sector.

By breaking down existing long-term contracting structures, alternative solutions emerged to address the specific needs of pipeline assets. One was 'take or pay' contracts in which producers required buyers to take specified volumes or pay for them if they did not. Masten and Crocker (1985) showed that the primary motivation for take-or-pay provisions was to ensure contractual performance, but regulatory price controls distorted the implemented terms. Similarly, Mulherin (1986) assessed the structure of natural gas contracts and found that a transaction costs view provided explanations most consistent with the empirical record.

While the NGPA moved away from the model of regulated bundling that had prevailed in prior decades, pipelines were still far from an unbundled transportation model. Because final consumers reacted to the higher prices allowed by removing price controls, a gas surplus flooded the market, indicating that market forces would be preferable to imperfect regulation. The positive effect on the market eased the introduction of further reform. This contrasts with the continued opposition of incumbents and producers to the

[31] The NGPA provided for the "new gas" wells to operate starting in 1985. Residual price controls on "old gas" wells were removed in 1989 through the Natural Gas Wellhead Decontrol Act.
[32] A merchant transportation model is fully unbundled. Integrated gas merchants would bundle gas and could potentially own production themselves.

liberalisation of the EU gas sector, which necessitated the use of competition policy to justify treating the entire network as essential facilities.

Further reform was necessary to bring natural gas transportation closer to a market-driven system. This started with FERC Order 380 in 1984, which prevented LDCs being forced to make minimum payments to pipeline companies. The following year, Order 436 initiated the process of establishing a contract-based system for pipeline transportation. Order 436[33] established a voluntary program that encouraged natural gas pipelines to become 'open-access' transporters of natural gas rather than integrated gas merchants who bundled commodity gas and transportation. In this sense, Order 436 reversed the decades-old guidance of the NGA, treating interstate transportation as a regulated public utility. Creating unbundled services opened the door to a contract carriage industry, in which different pipelines are paid to provide transportation linking many producers and buyers.

Makholm (2012, p. 133) cuts through the cloud of technicalities to expose the fundamental problems of market power and opportunism in a regime of bundled delivery by pipeline companies. "*Semi-rival regulated pipelines, which profit only through a return on their regulated transport investments, simply do not make responsible agents for the purchase of gas on behalf of captive distribution utilities, in illiquid markets dominated in long-term contracts. Trouble was inevitable (shortages, surpluses, heavy litigation, financial failure, etc.) until those distributors could buy gas in the field for themselves and simply contract with pipelines for the needed inland transport service.*"

While Order 436 moved the US towards more market-based transportation services, it did not wholly eliminate the market power of pipeline companies. Unbundled transportation was popular but not required. Another step was needed to eliminate bundling and ensure that shippers could access transportation on their terms. Building on the success of Order 436, the FERC issued Order 636 in 1992 to complete the unbundling of transportation and the commodity.

Order 636 effectively broke the market power pipelines could exercise by allowing for greater shipper choice on all pipelines, not just those in a voluntary program. After Order 636, buyers could contract with multiple potential suppliers, suppliers could sell to numerous buyers, and the transmission pipelines became an open-access system for delivering gas. This effectively gave buyers a choice of where to source gas and how to transport it. Orders 436 and 636 eliminated monopoly power over the gas commodity via bundling; non-discriminatory pipeline rates remain regulated by the FERC to constrain market power over the transportation service.

Order 636 also created a secondary market for pipeline capacity by allowing shippers to release their capacity[34] enabling other market parties to obtain gas supplies from

[33] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, 50 Fed. Reg. 42,408 (Oct. 18, 1985), FERC Stats. & Regs. ¶ 30,665 at 31,554 (1985).
[34] 18 C.F.R. § 284.243 (1993).

different supply interconnects along pipelines.[35] Shippers gained additional rights in flexible nominations, in-line and in-field transfers, and nominations from supply and market area ‘pools’ rather than individual receipt and delivery points which promoted the formation of market centres.[36] These ‘hubs’ provided liquidity and price discovery, replacing numerous siloed systems that offered bundled services.

Empirical evidence suggests that the net effect of Orders 436 and 636 was a more integrated national market (Avalos et al., 2016; Cuddington & Wang, 2006; De Vany & Walls, 1993, 1994; Doane & Spulber, 1994; Serletis & Rangel-Ruiz, 2004). This outcome is a realisation of the vision for a gas system based on light-touch monopoly regulation applied to individual pipelines, with the use of this infrastructure coordinated by market and contractual relationships over the long term rather than relying on regulatory oversight.

In 2002, FERC issued Order 637,[37] which was intended to eliminate the remaining market power of pipelines by allowing shippers marketing in the secondary capacity release market to compete more effectively with pipelines marketing their capacity.[38] Order 637 aimed to reduce the ability of pipelines to influence the secondary market unduly.

[35] “An interstate pipeline that offers transportation service ... may not include in its tariff any provision that inhibits the development of markets centers. [18 CFR § 284.8 (b) (4) and § 284.9 (b) (4)]”; *see also Northern Natural Gas Co.*, Docket No RP88-259-055, et al (October 20, 1992) mimeo a 6.

[36] “The number of market centers at least doubled in each of the two calendar years immediately following Order No. 636 and increased by more than 60 percent in 1995” (Holmes, 1999).

[37] *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, 90 FERC ¶ 61,109 (2000).

[38] Order No. 637 “effect[ed] changes in regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties to improve the competitiveness and efficiency of the interstate pipeline grid.”

Table 2: Major FERC Orders Restructuring Gas Pipeline Transmission

FERC Ruling	Date	Description
Order 380	1984	allowed LDCs to not honour contracts with pipelines for minimum payments
Order 436	1985	allowed pipeline companies to offer transportation-only service on a voluntary basis, providing an unbundled option for shippers
Order 636	1992	required pipeline companies to unbundle their distribution, sales, and storage services, effectively transforming pipeline companies from sellers to transporters of natural gas
Order 637	2002	adjusted rules for capacity release to allow greater competition with pipeline companies
Order 712	2008	removed remaining capacity release price ceilings and addressed asset management agreements

Despite the long arc of moving towards contractual governance of gas pipelines, innovations around gas marketing require continued attention to market access issues. The development of US regulatory design has been subject to continuous evolution. In 2008, Order 712 addressed the emergence of bundled asset management agreements while removing the remaining price ceilings on capacity releases. This reflected a maturing market that required additional definition and clarification, even as a vestigial regulatory instrument was removed. These are contractual relationships where a party agrees to manage gas supply and delivery arrangements, including transportation and storage capacity (FERC, 2008). These agreements are differentiated depending on their application to upstream and downstream parties.

3.3. Current functioning of the US market

As a result of the iterative history of economic regulation, US gas pipeline transportation today depends on a suite of defined contractual rights between pipeline owners and the owners of primary capacity. These rights are tradable, allowing owners to transfer their contractual rights on a short- or long-term basis. Reliance on these contractual rights serves as a substitute for more comprehensive regulation. However, a residual layer of regulation remains in setting rates for long-term capacity above one year and facilitating the development of new and uprated pipelines through open seasons. Mackholm (2012) refers to this as '*shifting from regulating rights to regulating the rights to legal transport entitlements*.' These rules from FERC provide a regular process and a crucial regulatory service in rate setting. Makholm (2012) described this design as a Coasian market, given its reliance on well-defined property rights that are tradable at low cost with readily available information. Under these conditions, decentralised trading will likely allocate resources efficiently – such as transportation capacity - to shippers who value them most. The market power of pipeline owners is proscribed by the definition of transportation rights and a small but essential regulatory role in reviewing rates.

Primary transmission capacity is allocated on a non-discriminatory basis according to an open access regime. The requirement is a TPA obligation to offer the service to any shipper who expresses an interest in a primary capacity. The later terms are negotiated between the pipeline and the interested market parties. The FERC regulates the minimum and maximum rates that can be charged to protect all shippers. Pipelines can offer different classes of service, most commonly firm and interruptible, as long as rates are non-discriminatory within each class of service.

The FERC establishes regulated rates for incremental pipeline capacity that serve as a backstop in the negotiated open-season procedures.[39] While rates had been regulated since the NGA, several possible methods were used. Order 636 specified that a straight fixed variable (SFV) method would be used to allocate fixed and variable costs, which is now embodied in reservation (fixed) and usage (variable) rates in pipeline tariffs. One advantage of the SFV approach is that it is more predictable than volumetric tariffs, lowering the transaction costs to trading primary capacity rights (Makholm, 2012, p. 144).

If shippers want more capacity than is available, the capacity can be prorated. Primary capacity refers to the right to transport gas along a designated route under contractually defined terms at a known price. Contracts for primary capacity are long-term, though they may be usurped by new terms under certain conditions discussed below. Different types of shippers can hold primary capacity, including consumers such as industrial or electric power users, LDCs, producers, or gas marketeers. These buyers can obtain gas before it is delivered and arrange transportation to suit their needs. The IEA (1998) highlighted the greater participation of these various types of consumers as a key innovation of the reformed US market. All other buyers can contract for gas and transportation directly or through gas marketing firms, except for residential customers, who are required to purchase from LDCs.

3.3.1. Access to pipelines on the short term: secondary market

The US secondary market is designed to function as a competitive spot market for transmission capacity with negotiated prices. Capacity can be made available to the secondary market in two ways. First, holders of long-term contracts can release capacity directly, a practice known as the 'grey market.' In general, these capacity releases can have a duration between several hours to the duration of the original contract (Mohlin, 2021, p. 17), though capacity with a duration longer than a year is subject to a price cap

[39] See Jamasb et al. (2008).

set by FERC.[40] Capacity releases are typically structured as interruptible service and represent a temporary transfer of the usufructuary rights in the pipeline to another party. The alternative mechanism is for unused capacity to be returned to the pipeline operator, which can offer it back to the market on an interruptible basis (Marks et al., 2017; Oliver & Mason, 2018, p. 261).

Prices in the secondary market are set based on opportunity costs at which the capacity is released. Without a cap, released capacity can exceed the two-tier regulated tariffs for incremental capacity. Traders holding capacity in congested routes can profit in two ways. They can use the capacity to transport the commodity and take advantage of the price spreads (De Vany & Walls, 1994), or alternatively they can resell their gas transportation rights to other users at market prices, including at prices above the original long-term capacity (Mohlin, 2021, p. 17). Oliver et al. (2014) find empirical evidence of this effect by examining connected nodes where congestion occurs at upstream nodes; Avalos et al. (2016) published a similar study investigating congestion at downstream points.

Such an event indicates that demand for transportation exceeds the supply in at least some periods. Observing capacity releases incentivises the pipeline owner to expand if these events are frequent enough. Observing secondary market sales that are profitable for primary shippers indicates that the pipeline owner is not capturing all of the value. A profit-maximising pipeline will try to assess demand and command rates that prevent this from happening. Open seasons are one way for pipeline owners to assess demand.

3.3.2. Investment framework: thresholds and open seasons

New investments in pipeline capacity must meet the 'threshold requirement,' which essentially requires projects to succeed without financial subsidies from current shippers (O'Loughlin et al., 2013).[41] This implies that capacity additions or new routes are financed on an incremental rather than systemic basis. The FERC considers various factors that affect the public necessity and convenience of additional capacity if sufficient demand exists (FERC, 1999).

The primary mechanism for determining demand for gas transportation services is the 'open season,' an opportunity for potential shippers to express interest in securing capacity on a specific route. Incremental pipeline capacity is only built where market interest confirms the need for more infrastructure. Protecting existing shippers from incurring additional costs for capacity is one motivation for requiring serious expressions of interest.

Open seasons are essential for gauging demand for investments on the intensive margin, such as uprating capacity on existing routes. They can also be used on the extensive margin, gauging interest in capacity over new routes. The speculative nature of extensive

[40] See, e.g., Oliver and Mason (2018) and David and Percebois (2004) for further discussion of the capacity release market in the US.
[41] See further discussion in FERC Statement of Policy (1999), pp. 19-22.

expansions may lead to different bidding behaviours than those for expanding existing routes.

Open seasons can be flexible, with pipelines allowed some discretion in how they are conducted so long as they meet minimum standards (Jost & Benson, 2016). An essential difference among open seasons is those that have binding commitments versus those that are non-binding. The latter involves less commitment and may be subject to varying degrees of discussion relative to a binding commitment. Some pipelines may initiate an open season to gauge demand for an expansion. Shipper interest can be gauged in terms of bids that can be formalised as precedent agreements. In this way, spreads between nodes act as a long-term incentive for the market to invest in pipeline infrastructure. Secomandi (2010) shows that spread options capture the value of transport to both the producer and end user.

During the binding phase of an open season, shippers' bids are typically evaluated based on the net present value (NPV) of their bids, considering the subscribed capacity and the duration of the contract. Shippers submitting a bid with the highest NPV receive the capacity, and this principle applies until all the available capacity has been allocated (Federal Registry, 2011; Jost & Benson, 2016). Following the open season, the pipeline and the market parties should sign a precedent agreement (PA), which includes specific details on the pipeline rates, the transportation path, the volumes, and the terms of services (Mohlin, 2021, p. 15).

Overall, the approach is designed to limit the development of incremental capacity to meet the market's needs, as expressed in the form of binding commitments. Finally, the risk of this infrastructure is borne by shippers booking the capacity, who can be seen as investors in the infrastructure asset as they acquire the risk associated with the long-term capacity (Oliver & Mason, 2018, p. 260).

4. EU regulation for natural gas transmission networks

The following section provides an overview of the regulatory design for EU natural gas transmission networks. It departs from the sector fundamentals, which have largely determined the regulatory objectives during the liberalisation process, including the EU's import dependency and the starting point of the process where the sector was structured around national monopolies and oligopoly characteristics for production. The section further assesses the main legislative acts and regulations to introduce requirements on unbundling, the E/E network model and regulated TPA. The effect of this framework is assessed in 4.3 on the 'pooling' service provided by regulated gas networks. Finally, Section 4.4 discusses the impact of this model on network investments.

This section also covers the regulations for using EU gas transmission networks, applicable to all time frames, including the short term, which has no equivalent in the US regime, where the market coordinates this function.

4.1. Supply and demand fundamentals

The supply fundamentals of the EU market differ significantly from those of the US and have shaped the regulatory design. The production and consumption of natural gas in the EU[42] started in Italy in 1948 and the Netherlands in 1959 (Craig et al., 2018). Exports across Europe started later, around the development of the Groningen field in the 1960s, and imports of Russian gas began in 1968 following the first LTC with OMV (Stern, 2005). Compared to the US reliance on domestic production, the EU natural gas sector has historically been characterised by import dependency from Norway, Russia, and Algeria, followed by LNG at a later stage. Domestic production represented 72 per cent of total EU consumption in 1990 but declined to 54 per cent in 2000, 38 per cent in 2010 and 13 per cent in 2020.[43] Natural gas is imported from production fields outside the EU via long-distance pipelines to domestic points in the Member States. Transporting gas over long distances has required capacity development, which crosses EU Member States. Before 2022, natural gas imports would cross several Member States before reaching their destination.

This development of the EU gas sector was based on standard netback contracts, which allowed the pricing of the commodity below competing alternatives (Stern, 2012). Producers assumed the price risk related to the commodity's competitiveness by pricing gas at a discount to oil. At the same time, off-takers committed to minimum take-or-pay (TOP) volumes to ensure continued returns on the upstream investment. Captive demand users underpinned the agreements,[44] which ultimately guaranteed the signed contracts. Both producers and buyers would agree to share the available rewards (Chyong, 2019; Stern, 1992, p. 9). The risk associated with the development of the sector, including transport pipelines, could be mitigated by the competitiveness of the

[42] https://visualizingenergy.org/the-history-of-global-natural-gas-production/

[43] Based on Eurostat.

[44] Initially, gas was introduced as a fuel alternative to coal and fuel oil, mainly for heating (Dilaver et al., 2014; Honoré, 2010).

commodity. As discussed in the section on hydrogen below, mitigating the volume risk of the transport infrastructure requires addressing the price risk of the commodity, specifically its competitiveness.

4.2. Liberalisation of the EU natural gas sector

The section reviews the liberalisation process from its initiation until the final regulatory model was established in the Third Energy Package. The section further refers to the use of the essential facility doctrine as part of competition policy, which the EC leveraged to support the development of sectoral regulation. The process resulted in regulations being applied to the entire network based on regulated TPA requirements, including access to the network on the short-term market.

4.2.1. The role of long-term contracts

The EU gas sector was historically developed around monopolies, either state-owned or heavily regulated companies, often vertically integrated, that guaranteed gas transport to end consumers (Stern, 1998). Gas trade has been predominantly based on long-term supply contracts with oil indexation, complemented by transit[45] agreements, extending for long periods, often above 20 years (Talus, 2011b). While long-term contracts enable significant fixed-cost investments, they can have an anticompetitive foreclosure effect, especially in newly liberalised markets, such as the EU, by limiting the entry of new market participants. This is particularly problematic when exclusivity contracts are used in large numbers in a specific market, tying the buyers and sellers for extended periods. These contracts may negatively impact the creation and liquidity of traded markets by locking in significant gas volumes over long periods, especially when combined with destination clauses and tacit or early renewal mechanisms. This and other restrictive clauses create competition law-related concerns (Talus, 2023).

The sector's liberalisation faced the dual challenge of introducing competition for the commodity at both wholesale and retail levels, as well as enabling third-party access to the infrastructure. Over time, the EC employed several tools to limit these agreements, acting separately on commodity and transport contracts. These actions included the EU Competition Law (Articles 101 & 102 TFEU) against restrictive clauses hindering competition, including destination clauses, resale restrictions, and take-or-pay obligations (Chyong et al., 2023), and then sectoral legislation over the three legislative EU rounds, as described in the next section.

[45] Before the various rounds of EU legislative reforms in the gas sector, transit was recognized as a separate legal concept, distinct from standard gas transportation within national markets. The definition of transit in the context of natural gas networks was primarily based on international agreements and early European directives, particularly under the Energy Charter Treaty (ECT) and pre-liberalization EU gas market rules. Article 7 of the ECT defined transit as "*the transport of energy materials and products through an area of a Contracting Party, when such transport is destined for another Contracting Party*." Council Directive 91/296/EEC of 31 May 1991 on the transit of natural gas through grids. was the first EU-level legal framework specifically dealing with natural gas transit. Transit was defined as the transportation of gas across at least one national border using a high-pressure grid.

Overall, the approach to introducing competition in the EU natural gas sector involved two possible strategies: the first required breaking up incumbents to allow smaller companies to compete in national markets. The second, by contrast, required enabling access to import infrastructure, thereby allowing previously monopolistic firms to compete across the EU. The EC advanced in both paths, combining competition policy, such as gas release programs,[46] with sector-specific regulation. The emphasis on enabling regulated TPAs at interconnection points for importing the commodity was linked to the difficulty of breaking apart long-term upstream commodity contracts signed between producers and EU purchasers (Hauteclocque & Talus, 2009). The EU regulatory design for utilising natural gas infrastructure was primarily driven by the objective of facilitating access in the context of high market concentration in wholesale markets. As discussed in the following sections, this approach has left an anti-trust imprint on the regulation. The high concentration in upstream and retail markets was used to introduce more extensive regulation for pipeline infrastructure, including considering networks as entire monopolies, with access to be granted to enable competition. This approach should be compared with the market acceptance of Orders 436 and 636 in the US, where legislative change was facilitated by the practical need to overcome the failure of well-head price regulation.

4.2.1. Three rounds of sector-specific legislation, 1998-2009

The Single Market Act of 1987 mandated the removal of all administrative and non-administrative obstacles between Member States for the free movement of people, capital, goods, and services across borders. The liberalisation of the EU energy sector started in 1990 as part of a broader effort to create an integrated and competitive EU market, routed in these four freedoms, including the free flow of energy between the countries.[47] Between 1998 and 2007, the EU adopted three successive legislative packages complemented with competition policy (Yafimava, 2013). The main design elements introduced in this process are summarised in Table 3 below. Key transformations include:

Retail competition was gradually introduced. Directive 98/30/EC laid the foundation for opening national gas markets to competition but did not mandate full retail choice for all consumers.[48] Directive 2003/55/EC accelerated market opening, setting 1 July 2004 for non-household customer eligibility and 1 July 2007 for all customers (including

[46] The experience of gas release programs has been reviewed by Chaton et al (2012) and Fischer (2018) .

[47] Since the judgment in Case 6/64 Costa v ENEL electricity (electrical energy) has been considered as 'good' subject to the principle of free movement of goods of the European Union (EU).

[48] Under Directive 98/30/EC only large industrial or high-consumption users could choose their gas supplier. Member States were required to progressively expand the definition of eligible customers over time, but no fixed deadline was imposed for full household access. Finally, some transparency obligations applied, but most retail consumer protections were left to national implementation, focusing primarily on large-user choice.

households). Finally, Directive 2009/73/EC consolidated retail competition obligations, ensuring all customers could choose their gas supplier.[49]

Unbundling requirements were strengthened. Directive 98/30/EC introduced a requirement for accounting unbundling, leaving the implementation at the discretion of Member States. Overall, vertical integration remained largely intact. Directive 2003/55/EC required TSOs to be legally separate entities within a vertically integrated undertaking, implying distinct legal management from the supply business, although still under the same parent company. At the same time, it strengthened the role of NRAs to oversee unbundling compliance. Finally, Directive 2009/73/EC introduced three unbundling models: ownership unbundling (OU), independent system operator (ISO), and independent transmission operator (ITO).[50]

TPA requirements were strengthened from negotiated TPA to regulated TPA, which was applied to entire networks. Initially, the First Package foresaw applying negotiated or regulated TPA. This resulted in most networks applying regulated TPA except Germany, which relied on negotiated TPA. Germany implemented industry agreements, known as the Verbändevereinbarungen or 'VV Gas,' rather than a comprehensive regulated tariff framework, which aimed to foster competition by allowing different shippers to negotiate pipeline access. This did not lead to robust pipeline-on-pipeline competition, partly because large integrated companies retained significant market power (Lohman, 2006, Chapter 3). Directive 2003/55/EC established regulated TPA to be implemented nationally. Following the sector inquiry that pointed to the patchy outcome of this approach, Directive 2009/73/EC harmonised the regulated TPA approach by introducing an E/E model of the network and developing TPA rules in the Network Codes.

The type of service provided by the infrastructure was homogenised based on the E/E model, including the removal of transit as a separate legal concept. This led to the homogenisation of all services offered by transmission pipelines, ranging from regional networks (similar to distribution networks) to long-distance pipelines with lower unit costs. The approach limited, if not removed, the scope for pipe-to-pipe competition.

Transit was integrated under the TPA regime. Initially, Directive 91/296/EEC established minimum obligations for transit but did not integrate them with broader third-party access (TPA) rules. Directive 98/30/EC introduced third-party access (TPA). However, transit flows could still operate under separate 'transit' agreements, often long-term contracts, leaving significant discretion to Member States regarding the integration of transit into national frameworks. The Directive 2003/55/EC ended the special legal

[49] Directive 2009/73/EC enhanced consumer rights by requiring clear switching processes with no fees or obstacles and obligations for suppliers to provide clear pricing and contract details, making it easier for retail customers to compare offers and switch supplier.

[50] Under ownership unbundling (OU) the same person/entity cannot control both transmission and production/supply. Under the independent system operator model (ISO), the TSO is managed by an independent operator, though assets may remain under a vertically integrated company's ownership. Finally, the independent transmission operator model (ITO) is a stricter form of legal and functional unbundling with robust compliance requirements.

status for transit pipelines, requiring all cross-border gas flows to adhere to non-discriminatory TPA rules.[51]

The overall trend observed from Directive (EC) 98/30/EC to Directive (EC) 2009/73/EU was a move toward regulation applied to the entire network based on regulated TPA requirements for offering services in the short term. This should be compared with the previous coordination of the sector based on long-term contracts (Talus, 2011b, p. 266). This approach can be characterised as a general effort to use regulation to introduce competition (Talus, 2014, p. 31), transforming a sector dominated by national monopolies into national interconnected gas markets.

Table 3: EU sectoral legislation for the liberalisation of the EU natural gas sector

EU sector regulation		**Date**	**Description**
Transparency Directive	Directive 90/377/EEC.	1990	Introduced transparency requirements to facilitate competition by providing comparable pricing information across Member States.
Transit Directive	Directive 91/296/EEC	1991	Introduced non-discriminatory requirements for access to transmission infrastructure subject to significant limitations.
First Package	Directive 98/30/EC	1998	Introduced a choice between regulated TPA and negotiated TPA, dispute settlement arrangements (although no formal NRAs), abolition of import monopolies, gradual market opening, and accounting unbundling for vertically integrated network companies.
Second Package	Directive 2003/55/EC	2003	Established NRAs and regulated TPA at a national level.
	Gas Regulation 2005/1775/EC	2001	Provided details on the regulated TPA requirements including on network tariffs, capacity allocation auctions, secondary trading for capacity rights and balancing. These requirements applied nationally with no harmonisation at EU level. Additional transparency requirements.
Third Package	Directive 2009/73/EC	2009	Introduced three models of unbundling for TSOs and regulated TPA at EU level.
	Regulation (EC) 715/2009	2009	Introduced the E/E model and regulated TPA to be developed in a harmonised manner across the EU in the specific Network Code regulation.

[51] Pre-existing transit contracts concluded before the directive's entry into force could remain in place, subject to a "grandfathering" approach, namely the contracts were allowed to run until expiration, provided they did not unduly hamper competition or block third-party access for other users. Similar transitional allowances applied to certain long-term supply contracts that were signed prior to full market opening, on condition that they complied with EU competition law and did not undermine market liberalisation objectives.

EU sector regulation		Date	Description
Network Codes	Congestions Management Procedures Guidelines	2012	Aim to address contractual congestion by reallocating unused capacity back to the market. Introduces four mechanisms: Oversubscription and Buy-Back, Firm Day-Ahead Use-It-Or-Lose-It, Surrender of Contracted Capacity, Long-Term Use-It-Or-Lose-It.
	Capacity Allocation Mechanisms Network Code	2013	Standardises the rules for offering capacity differentiating duration (daily, monthly, quarterly, and yearly) and quality (firm and interruptible). Requires bundled capacity between connected networks. Capacity is allocated using market-based auctions at shared platforms using uniform timetables across the EU.
	Balancing Network Code	2014	Standardizes gas balancing rules across the EU's E/E networks. It shifts the balancing responsibility from TSOs to network users. Requires market-based balancing and a daily balancing regime.
	Tariff Network Code	2017	Establishes rules for setting tariffs requiring a single reference price methodology (RPM) applied to all points of the network. Sets requirements on cost-reflectivity, non-discrimination, prevention of undue cross-subsidisation and transparency.
Fourth Package	Hydrogen and Decarbonised Gas Market package	2024	Introduced rules for the decarbonisation of the EU natural gas sector and for hydrogen networks.

4.2.2. Competition law and the essential facility doctrine

Given the slow progress in developing competition and further integrating EU gas markets through sector regulation, the EC opted for the parallel use of competition rules to push forward the liberalisation process.[52] The approach justified applying stronger unbundling and TPA requirements to the network based on the essential facility doctrine. Ultimately, this approach supported treating all pipelines as individual networks as an way to ensure competition by guaranteeing access to networks.

Following the Second Directive in 2005, the EC launched a sector inquiry to assess the development of competition in the EU natural gas market (EC, 2007). The inquiry was

[52] Competition law typically offers ex post and case-by-case solutions, lacking the comprehensive objectives expressed by sector-specific regulation (Larouche & Streel, 2020) . Conversely, sector-specific regulation tends to incorporate competition rules and objectives, although recent applications of competition law have not always considered sector-specific contexts and parameters. Despite this, competition law holds hierarchical priority over sector-specific rules and can be directly applied when sector regulation is insufficient or inefficient. Structural interventions based on competition rules should adhere to the principle of proportionality and be applied only in cases where market organization and poor regulatory supervision allow continued high vertical integration and anti-competitive practices.

preceded by an EC report on the progress in creating an internal gas market (EC, 2005), which has already highlighted the shortcomings in developing the EU internal market, including the slow implementation of Directive 2003/55/EC, particularly regarding unbundling rules, the lack of price convergence across the EU, and the low level of cross-border trade. The sector inquiry further concluded that Directive 2003/55/EC and Regulation (EC) No 1775/2005 did not provide the necessary framework for achieving the objective of a competitive and transparent internal gas market.

In the sector inquiry, the EC indicated that problems for developing competition related to the continued high levels of concentration upstream, underinvestment in key infrastructure necessary to enable competition, slow implementation of unbundling provisions, insufficient liquidity at virtual trading hubs, ineffective price formation, limited access to gas volumes, limited access to cross-border capacity, congestion at interconnection points and limited transparency. These conclusions are summarised in Table 4 below, showing the share of imports across selected Member States controlled by incumbents. Figure 5 below illustrates the share of trading by incumbents at EU gas hubs. The EC identified the lack of adequate third-party access to transportation capacity as one of the key factors preventing competition. The sector inquiry showed that most of the import and transit capacity was controlled by vertically integrated incumbents. These capacity reservations were based on pre-liberalisation capacity contracts, most of which did not expire before approximately 2020 (EC, 2007, p. 73).

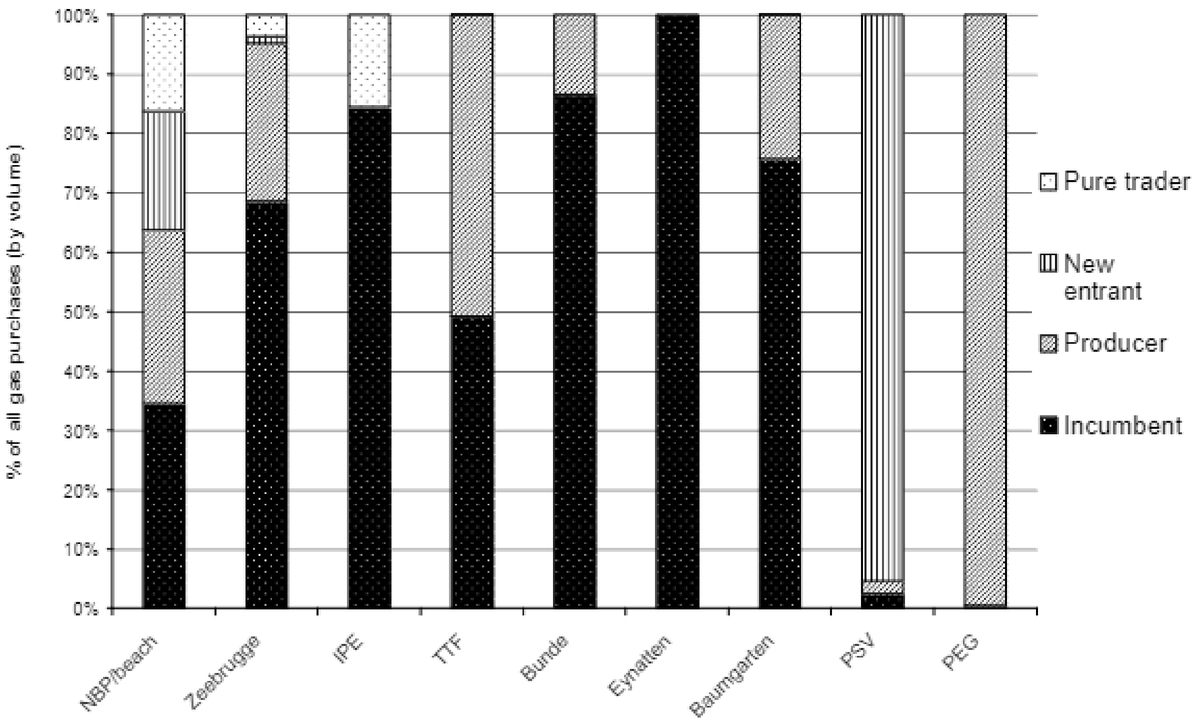
Table 4: Incumbents share of imports across selected EU Member States. Source: EC sector inquiry report, Table 1.

	Total imports (2004, in bcm)	Incumbent share of imports (2004)	Total domestic production (2004, in bcm)	Incumbent share of domestic production (2004)
Austria	9	80-90%	2	-
Belgium	16	90-100%	0	-
Czech Republic	9	90-100%	<1	-
Denmark	0	-	10	80-90%
France	49	90-100%	1	-
Great Britain	13	20-30%	105	40-50%
Germany	88	90-100%	18	80-90%
Hungary	11	90-100%	3	90-100%
Italy	67	60-70%	13	80-90%
Netherlands	18	50-60%	73	90-100%
Poland	10	90-100%	5	90-100%
Slovakia	7	90-100%	<1	-

Following the sector inquiry, the EC launched several competition investigations under Article 102 TFEU into alleged abuses of dominance, pointing at the refusal to provide access to transmission networks. The refusal to provide TPA may foreclose competitors from accessing downstream markets, which can be classified as an exclusionary abuse

(Dziadykiewicz, 2007). In seven out of the eight investigations, the companies offered commitments to address the EC concerns and settle the case. These commitments, made binding through so-called commitment decisions, included structural measures (such as network divestitures) or behavioural remedies (such as agreements to enable or improve access to the network), which were later incorporated into the Third Energy Package in the form of regulation (Dziadykiewicz, 2007).

Figure 7: Trading at EU gas hubs by market participant during 2003-2004. Source: EC Sector Inquiry report, figure 7.



The EC argued alleged infringement of Article 102 TFEU through the application of the essential facility doctrine (EFD)[53] to natural gas import pipelines, certain internal pipeline sections *and* LNG import terminals (Dziadykiewicz, 2007; Hauteclocque et al., 2011; Talus, 2011a) referring to the Bronner Case[54] [1998] ECR I-7791. The concept of essential facilities was first defined by the European Court of Justice (referred to as 'the Court') in the Bronner case by setting four necessary conditions for applying the essential facility doctrine. In the Bronner case, the Court argued that "*the most economic route should not be considered as an essential facility where other routes exist, though less economic"* (Talus, 2011a). Accordingly, not all pipelines necessarily qualify as essential facilities.

According to Talus (2011a, p. 1590), the EC sought to justify the existence of exclusionary abuse by considering entire networks, rather than just individual assets, as essential facilities. The EC might have extended the concept to cover the entire network, including

[53] The essential facility doctrine consists of four elements: *i)* control of the essential facility by a monopolist, *ii)* a competitor's inability to duplicate the essential facility, *iii)* the denial of the use of the facility to a competitor, and *iv)* the feasibility of providing the facility[53] (Hawker, 2005, p. 35).
[54] *Oscar Bronner GmbH & Co. KG* v *Mediaprint Zeitungs- und Zeitschriftenverlag GmbH & Co. KG*, Case C-7/97, ECLI:EU:C:1998:569.

all import facilities. *"Import pipelines are often controlled by a single company, the gas TSO, and while import pipelines are in principle alternatives to each other, together they have an essential facility character. The ability of the competitors to challenge the incumbent is dependent on TPA to the entire network. The fact that a particular LNG facility may not be controlled by the transmission system operator does not affect this approach as often this only represents a small-scale alternative".* In addition, "where a *TSO attempts to prevent access to the downstream markets through the control of importation capacity, it will use its entire network of import points to block entry".*

The EC's approach to considering the entire transmission network as an essential facility to which access is required to allow effective competition is discussed at length in the literature (Hauteclocque et al., 2011; Talus, 2011a). This literature argues that the principles originating from the EFD developed by the ECJ and later modified by the EC in gas competition cases influenced rules under the Third Energy Package and resulted in the strengthening of both the TPA regime and the unbundling requirements (Dziadykiewicz, 2007). The rules of the Third Energy Package, including the application of monopoly regulation to entire networks, the use of an E/E model, and the application of TPA requirements, can be considered as the adaptation of a competition instrument – the essential facility doctrine – into sectoral regulation. In this manner, the regulatory framework for the EU's natural gas network was given a lasting imprint by antitrust considerations.

The concept of essential facility is, in essence, the opposite of property rights and incentives to invest in infrastructure (Talus, 2011a) and leads to a classic trade-off in competition law between static (or allocative) efficiency and dynamic (or productive) efficiency. The requirement to provide short-term access to parties may enhance consumer welfare in the short term. However, the monopoly position of the infrastructure's owner is, from a Schumpeterian perspective, the first incentive to invest (Hauteclocque et al., 2011, p. 266). The different approaches to applying the essential facility doctrine in the EU and the US have been discussed in the literature (Hauteclocque et al., 2011; Talus, 2011a) referring to the different approaches to antitrust. While the EC tends to expand the scope of application of the essential facility doctrine, the US Supreme Court strictly circumscribed its antitrust competence.

4.3. Access to networks

Applying unbundling and TPA rules and removing the possibility of point-to-point transport (in the form of a distinct legal status for transit or under negotiated TPA rules) resulted in the establishment of network monopolies operated by TSOs. Natural gas networks, as defined in the EU, are complex systems with the complexity being the result of a design choice. While distribution and city-level pipelines connecting homes and businesses are inherently complex due to their physical nature, the complexity in transmission networks results from the choice to bundle large pipelines with distinct sources and destinations into a single mashed network.

The following section presents the details of the regulated TPA access rules to transmission networks as developed in the Network Codes. The section continues by analysing the change in network service type compared to the point-to-point service provided by individual pipelines. This paper refers to the service as a 'pooling' service.

4.3.1. Network Codes

The use of E/E networks is established around the concept of access to networks, which encompass rules for offering capacity, including the short-term (NC CAM), pricing capacity products (NC TAR), balancing (NC BAL), and congestion management (CMP GL), as summarised in Table 3 above. Ultimately, E/E networks enable users to access the market where commodities can be traded, and they are established as virtual trading points that overlap with individual E/E networks. These instruments are integrated into the EU internal gas market model known as the 'Gas Target Model' (ACER, 2015; CEER, 2011).

The rights to access the network were established in Regulation (EC) 715/2009 and detailed in the CAM NC, which set the rules for offering capacity at entry and exit points. Capacity is offered at auctions conducted on the booking platform and contracted separately for entries and exits. This ultimately underpins the provision of free zonal flexibility, as explained in Section 4.3.2 below, which enables access to the virtual trading points.

The principles for setting tariffs for access to the network were outlined in Article 13 of Regulation (EC) 715/2009 (repealed in Articles 17, 18, and 19 of Regulation (EU) 1789/2024) and further detailed in the NC TAR. Tariffs should reflect costs. However, this principle is applied at the network level as a requirement to recover the allowed revenue of the TSOs with limited options to reflect the underlying asset costs. This approach enables a regulated approach to recovering investment costs, which should be compared to the US regulatory model, where parties subscribing to long-term capacity face some degree of risk when recovering the investment, primarily due to the short-term market not being subject to regulation that ensures the recovery of sunk costs.

Tariffs are set to recover the costs of entire networks, which implies a regulated approach to recovering sunk costs. This is deemed necessary to ensure the recovery of network investments similar to the guarantees provided by the LTCs in the US model. In the EU, tariffs recover the network costs across all network users. This leads to challenges when integrating E/E networks into a single EU market. The benefits for liquidity are realised when socialising flexibility costs across network users. When it comes to transporting gas to neighbouring E/E networks, tariffs socialise costs intended to enable liquidity at the national level rather than optimising transport across long distances. This leads to the so-called 'pancaking' effect assessed by the EC (EC, 2017)[55] where users transporting

[55] The term "pancaking" has also been used to refer the adding up of tariffs when transporting gas across various EU borders. Crossing each border requires paying for the tariffs applicable at each interconnector point, to exit a network and to enter the next network. This use of the term simply refers to the additionality of tariffs without distinguishing the costs of flexibility associated with each network that is crossed.

gas across networks have to pay for the costs of flexibility for each network (i.e. access to the market) regardless of whether they benefit from this service. A similar problem occurs when allocating cross-border infrastructure costs to the two connected networks. The distribution of costs might not be symmetric, so the incentives to share these costs can be limited.

Instead of reflecting the costs of individual assets or transport routes, users pay for access to entire networks, which grants them subsequent access to the virtual trading points enabled by this network infrastructure. The NC TAR allows for some degree of approximation to the actual infrastructure cost when booking capacity. However, compared to the costs of tariffs set for individual assets or routes, these approximations are largely inaccurate and/or require assumptions that are hard to reconcile with EU rules.[56]

In the event of network congestion, the premia registered in the capacity auction is returned to network users (in the form of decreases in future tariffs applicable to all network points) or infrastructure investments to alleviate congestion.[57] This is consistent with the fact that network users ultimately bear the risk of network infrastructure.

The model is designed to accommodate short-term capacity offers. Capacity quotas require 20 per cent of the annual capacity to be offered for short-term products.[58] At the same time, the model allows for capacity to be offered up to fifteen years in advance. This is only possible by combining yearly capacity products for subsequent years.[59] This requirement, which aims to promote competition by ensuring short-term access to the network, disincentivises investments in infrastructure as capacity booked for longer timeframes coexists with capacity offered on the short-term market.

4.3.2. Pooling network services

The Third Energy Package fundamentally changed the service provided by pipelines as well as the trading of the commodity. Under the point-to-point model, individual pipelines are dedicated to transporting gas from a specific origin to a designated destination. Under an E/E model, the infrastructure provides a service as an entire network, allowing the transport of gas while also offering flexibility to trade gas in the market while it is within the network. This paper refers to this service as 'pooling' in contrast to traditional point-to-point transport, which is provided by pipelines.

In natural gas trade, physical constraints related to location and time typically govern transactions. The E/E network model expands these constraints spatially (i.e., by extending transport scope through individual pipelines to the entire network) and temporally (i.e., by balancing gas throughout the entire day). Therefore, gas within a zone can be traded regardless of its precise location or the time of injection or withdrawal. By

[56] See the two ACER reports published on the consultation for the transmission tariff structure for France in 2019 (link) and 2023 (link).
[57] See Article 19(5) of the NC TAR.
[58] See Article 7 of Commission Regulation (EU) 2017/459.
[59] See Article 11(3) of Commission Regulation (EU) 2017/459.

reducing the spatial and temporal specificity of the commodity, the E/E model homogenises commodity trades. This standardisation makes all parties that access the network eligible for trading gas and, in this manner, supports liquid trading at virtual hubs, often referred to as 'commercial hubs' (Hallack & Vazquez, 2015; Vazquez et al., 2012a, 2012b, 2013).

The flexibility to access the market has two components. First, a spatial one related to capacity bookings; second, a temporal one related to balancing. Regarding the former, the E/E model allows users to book entry and exit capacity separately. This enables shippers to trade, changing ownership of gas within the market (KEMA, 2015). Second, balancing services offer temporal flexibility, allowing shippers to manage imbalances within each gas day and remove time-specific transaction constraints. These features reduce the commodity's spatial and temporal specificity, promoting uniform trading conditions.

The pooling service offered by E/E networks thus extends beyond point-to-point gas transport. It offers zonal flexibility across the network, the costs of which are later socialised across users through network tariffs. Network users pay for the flexibility to access the network regardless of whether they transport gas or access the market.[60]

The E/E model was initially adopted in the UK, where computational constraints made calculating tariffs for each point-to-point combination within the network slow and burdensome. However, market participants soon realised that gas ownership could change freely once in the network (Juris, 1998). The success of this approach in fostering competition in the country led to its eventual adoption in the EU. It is important to note, however, that the discussion leading to its adoption in the Third Energy Package was mainly led by Members States with downstream markets (i.e. UK, Germany, France, Italy), for which developing market competition, hence network flexibility, was a priority. Other Member States, where gas transport was a priority compared to access to liquidity, were not as vocal in the policy discussions (e.g., Belgium, Slovakia, and the Czech Republic). The E/E model unified all infrastructure services under a pooling service, which was more relevant in downstream networks with a greater reliance on balancing and market liquidity compared to more transport-oriented networks, mostly in Eastern Europe.

Three characteristics of the E/E model are particularly favourable to enhancing competition. First, large network zones reduce incumbents' market power by broadening the number of participants in the market. Second, the model lowers barriers for market participants lacking long-term supply contracts, allowing them to procure gas within the network. Third, the standardised commodity within each zone facilitates frequent and efficient trades, reinforcing liquidity.

[60] Conditional capacity products offer the possibility of contracting point-to-point capacity without access to the market.

4.3.3. Costs of pooling services

The provision of zonal flexibility fosters liquidity but comes at a cost. First, it requires additional network capacity to guarantee the flexibility provided to network users. Firm capacity is offered separately for entries and exits; therefore, the total capacity offered is subject to assumptions regarding the potential use of the network. In the absence of congestion, this implies additional infrastructure costs. However, in the event of congestion, these limitations lead to higher wholesale prices across markets.

Second, congestion within the zones cannot be signalled. Because capacity is not explicitly priced or booked within the entry-exit zones, local bottlenecks are not adequately reflected in market signals. This makes it difficult for users to anticipate or respond to internal constraints, thereby reducing the efficiency of infrastructure use and delaying targeted investment. Instead of exposing congestion through locational pricing, the E/E model often masks it, requiring TSOs or regulators to limit capacity across other points of the network.

Third, the optimisation of capacity and balancing services the network offers is established by TSOs, not the market. The offering of capacity and flexibility is mutually exclusive, so offering one unit of flexibility services decreases the available resources for transmission (Hallack & Vazquez, 2014, p. 494). Enabling flexibility to access the market can limit the amount of gas transported across the network.

Fourth, the services required to provide network flexibility do not necessarily have natural monopoly characteristics. Therefore, this service could be provided with flexible gas volumes that are available across the network. This implies that the establishment of network monopolies for the provision of pooling services results in the regulation of services that the market can deliver. The socialisation of flexibility costs reduces the value of market flexibility.

Finally, investment signals are significantly dampened due to the zonal model and the combined transport and flexibility services offered. The associated lack of signals for transmission constraints limits the potential for network signals to guide investments (Hallack & Vazquez, 2015). For instance, it is possible to identify the need for investment to reduce the price difference between two virtual trading points. However, the TSOs involved decide on one specific project among all the possible ones. There is a risk that such a decision may not be taken to optimise commodity trading. The dampening of market signals results in an information gap overcome by central planning instruments (Hallack & Vazquez, 2015), as described in Section 4.4 below.

The E/E model facilitates liquidity at virtual trading points and can be an efficient model when demand is stable, and infrastructure has already been established. However, the higher capacity requirements and the dampening of investment signals potentially render it inefficient where network expansion is a priority.

4.3.4. Rights under third-party access

The regulatory design developed under the Third Energy Package differs from the point-to-point model, which allows for private financing of infrastructure through long-term contracts. On the one side, the allowed revenue for TSOs guarantees cost recovery, like that of LTCs. Conversely, the rights for network uses are subject to more uncertainty than the equivalent LTCs.

Concerning the recovery of network investments, Article 41(6) of Directive 2009/73/EC (repealed by Directive (EU) 2024/1788) established the NRA's competence to set the allowed revenue of the TSOs, which includes a guarantee for the repayment of network investments.[61] This provides a guarantee similar to a long-term contract but applicable to the costs of the entire network. The NRAs act on behalf of network users to approve the remuneration of TSOs, for which network users guarantee full repayment. Tariffs set for capacity offered as a pooling service recover the network costs and, at the same time, provide a guarantee for cost recovery. In this manner, tariffs serve as an instrument for cost recovery and risk mitigation. In the context of hydrogen, where the user base is insufficient to mitigate the investment risk, an alternative guarantee is needed to develop infrastructure.

The rights for the network use were detailed in Directive 2009/73/EC (repealed by Directive (EU) 2024/1788), Regulation (EC) 715/2009 (repealed by Regulation (EU) 1789/2024) and the Network Codes.[62] The rights users hold when purchasing network services are subject to the access conditions established in EU legislation. Compared to long-term contracts, these access conditions are subject to more significant uncertainty, including, for example, updates on tariff levels (typically yearly), updates on the methodologies to calculate tariffs (at least every five years), recalculation of the capacity offered at network points whenever necessary, such as in cases of critical demand changes, and the commissioning of new infrastructure.[63] Users can book capacity long-term, but they will not be aware of the capacity available and the tariffs at other points in the network over time.

The conditions established in the regulation for access to networks do not ensure the value of the rights to the same extent as the tradable property rights for pipeline capacity in the US. Makholm (2012, Chapter 8) refers to the absence of an EU-wide regulator and

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[61] See Chapter IV of the NC TAR on the reconciliation of revenue. In particular, Article 17(1)(b) requires that *the level of transmission tariffs shall ensure that the transmission services revenue is recovered by the transmission system operator in a timely manner*. In addition, Article 13 or Regulation (EU) 715/2009 requires that tariffs reflect the actual costs incurred by the TSO.

[62] The rights to use EU natural gas transmission networks are based on national public law in the form of specific administrative law for energy, incorporating the EU sectoral legislation. Directive 2009/73/EC is transposed to national public law; Regulation (EC) No 715/2009 is directly applicable at the national level; finally, the Network Codes are translated and adopted at the national level.

[63] Article 6 of the CAM NC on " capacity calculation and maximisation" requires TSOs to regularly assess and maximize the technical capacity available at interconnection points.

the split regulation between the EU and its Member States as limitations to adopting the US model in the EU.[64]

4.4. Investment framework

The investment framework for natural gas network infrastructure is governed by the competencies and obligations laid down in Directive 2009/73/EC (repealed by Directive (EU) 2024/1788), Regulation (EC) No 715/2009 (repealed by Regulation (EC) 715/2009), and the relevant Network Codes, which apply to National Regulatory Authorities (NRAs), Transmission System Operators (TSOs), and network users. In addition, the TEN-E Regulation – initially Regulation (EU) No 347/2013 and revised by Regulation (EU) 2022/869 – provides EU-level rules for coordinating cross-border investments. Investments in network infrastructure may occur as:

1. Regulated investments financed by all network users.
2. Regulated investments financed by specific users of the infrastructure.
3. Exemptions (now discontinued for interconnectors under Directive (EU) 2024/1788).

Overall, the investment framework is primarily determined by three factors. First, introducing competition at the retail level removed the possible guarantees for infrastructure from captive consumers. Second, the scope of regulation to the entire network has limited investment signals, placing greater reliance on coordination and central planning. Lastly, introducing TPA requirements has limited the incentives for market-based investments. If the facility owner cannot fully capture the returns on its investment - because it must share the facility - its willingness to take on risk decreases. The EU regulatory framework promotes competition and allocative efficiency within the market, striking a balance between the long-term benefits of infrastructure investments and the need for market access and dynamic efficiency.

4.4.1. Regulated investments financed by all network users

These are infrastructure projects approved by national authorities and implemented by Transmission System Operators (TSOs) following a Final Investment Decision (FID). The CAPEX is included in the TSO's Regulatory Asset Base (RAB) and recovered through the allowed revenue set annually during the regulatory period.

These costs are socialised via capacity tariffs subject to TPA, calculated according to the Network Code on Tariffs (NC TAR) and levied at all network points. This means all network users share the costs, regardless of whether the project provides additional capacity for a single point or the entire system (e.g., a new compressor station). This approach is sometimes referred to as central planning.

EU sector-specific legislation does not prescribe detailed rules for these purely national-level investments. National authorities, such as national regulatory agencies (NRAs) or

[64] See footnotes 36,36,37 (Makholm, 2012, Chapter 8).

relevant ministries, typically rely on national instruments (e.g., investment plans, rate-of-return regulation, cost-plus frameworks) to approve such projects. However, cross-border infrastructure requires additional coordination. The TEN-E Regulation offers a framework for this purpose, including joint scenarios and security of supply assessments; identification of infrastructure gaps via Ten-Year Network Development Plans (TYNDPs); EU Projects of Common Interest (PCIs), which may receive financial support; cost-benefit analyses (CBAs) and Cross-Border Cost Allocation (CBCA), allowing NRAs to allocate costs in proportion to the distribution of benefits (including security of supply and sustainability externalities not priced by the market).

Although political considerations may influence final investment decisions, the EU framework provides tools to quantify costs and benefits, ensuring that externalities (e.g., security of supply and decarbonisation) are recognised.

4.4.1. Regulated investments financed by specific users of the infrastructure

Before 2017, the market had used open seasons to develop new infrastructure. The EU approved the Commission Regulation (EU) 2017/459, which amended the Network Code on Capacity Allocation Mechanisms (CAM NC), introducing the incremental capacity[65] process to let the market (i.e., specific shippers) finance infrastructure (CEER, 2012). Under this mechanism, market participants could book incremental capacity long-term (up to 15 years ahead)[66] via a two-step open season.[67] Shippers would bear the risk of financing the infrastructure, although some costs could be partially socialised across the network.[68] TPA requirements are relaxed by reducing the obligation to reserve 20 per cent capacity for short-term shipments to 10 per cent.

Since its introduction in 2017, the incremental capacity process has only produced a successful market test for the TAP pipeline, which opted for an alternative allocation mechanism (ENTSOG, 2023). ENTSOG (2023) explains this outcome in terms of market fundamentals related to the large interconnection capacity across EU networks and the capacity available to the market after the termination of legacy contracts. ENTSOG additionally explain this outcome by referring to factors related to market design,

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[65] According to Article 3(1) of Commission Regulation (EU) 2017/459 (amending the CAM Network Code), "'*incremental capacity' means a possible future increase in technical capacity that may be offered based on investment or the upgrade of existing infrastructure, or the establishment of a new interconnection point that is not yet created but for which there is a possibility that capacity could be offered*."

[66] See Article 28(2) of Commission Regulation (EU) 2017/459 (amending the CAM Network Code).

[67] Under the incremental capacity process the open season typically comprises two steps: (1) a non-binding phase, where market participants indicate their interest in incremental capacity, and (2) a binding phase, where shippers make firm capacity commitments.

[68] Under the incremental capacity process (Commission Regulation (EU) 2017/459), the f-factor is a parameter set by the NRA that determines what share of the incremental capacity costs is recovered from all network users via general tariffs. The remainder must be covered by the long-term capacity bookings of the shippers who triggered the incremental project, thus balancing overall system financing with user-specific cost responsibility.

including the shift from long-term to short-term and regulated investments, which limit the incentives for market investments.

Additionally, providing flexibility in the form of pooling services leads to significant slack capacity in the network, which is necessary to accommodate users' flexibility in booking separate entries and exits. This limits the spreads between markets, reducing the incentives to invest.

4.4.2. Exemptions

Article 36 of Directive 2009/73/EC permitted exemptions for new interconnectors, LNG terminals, and storage facilities, exempting them from specific provisions (e.g., unbundling, TPA), subject to several conditions.[69] With Directive (EU) 2024/1788, interconnection exemptions are no longer possible.

Exemptions have been applied [70] to various interconnector projects (Yafimava, 2018). By lifting TPA requirements on tariffs, project promotors are exempted from the application of allowed revenue regulation for infrastructure costs. This allows tariffs to be set for the lifetime of the infrastructure, which is not subject to review during the regulatory period, thereby facilitating project financing. Exemptions further limit unbundling requirements and offering capacity to third parties, including on the short term. When stripping investments from TPA requirements, the pooling service reverts to a point-to-point transport service, with its long-term rights restored. Exemptions are sought to transport gas to demand points, so the TPA requirements that turn point-to-point transport into a pooling service are unnecessary.

[69] Article 36 of Directive 2009/73/EC establishes several requirements to grant exemptions, which must be approved individually by each Member State. The project should (a) enhance competition and security of supply; (b) would not be built without the exemption (investment risk); (c) is owned by a legally separate entity; (d) applies user charges without discrimination; (e) does not harm competition or the internal market; and (f) is notified to the Commission, which may amend or revoke the exemption.

[70] The list of exempted projects is published by the EC (https://energy.ec.europa.eu/topics/markets-and-consumers/wholesale-energy-market/access-infrastructure-exemptions-and-derogations_en) and includes the following projects: BBL (Netherlands–UK, 2004), OPAL (Germany, 2009), NEL (Germany 2013), TAP (Greece–Albania–Italy, 2013), Gazelle (Czech Republic, 2012). On OPAL, see Yafimava (2017).

5. Regulatory Design Options for EU Hydrogen Pipelines

This section applies the economic framework developed in Section 2 to the hydrogen transport sector, outlining two high-level regulatory design options for developing hydrogen pipeline infrastructure in the European Union. The Hydrogen and Decarbonised Gas Market package extends principles from the Third Energy Package for natural gas to the emerging hydrogen sector, introducing regulated third-party access (TPA) based on an entry-exit (E/E) network model.

Drawing on comparative insights from the regulation of natural gas markets in the United States (Section 3) and the European Union (Section 4), this section presents two alternative approaches to regulating hydrogen pipelines. The first option extends the EU gas network model, which regulates entire networks to facilitate market liquidity and standardisation. The second option proposes an alternative market design based on pipeline-level regulation and market-led coordination inspired by the US natural gas market framework.

These two approaches are illustrated in the German and French approaches to developing hydrogen infrastructure. The former is based on developing a core hydrogen network following the example of natural gas networks[71]. Regulated third-party access is applied to the core network, including infrastructure to supply domestic customers and import infrastructure (interconnection points). The approach requires developing network codes for offering TSO services (essentially for offering capacity, setting tariffs and balancing) before the market is developed.

The alternative approach is illustrated in the French hydrogen strategy[72], which foresees the creation of hydrogen valleys to gradually scale up production and demand. These clusters integrate various industrial and mobility applications within a specific region to achieve economies of scale and reduce costs.

It is essential to note that the structural conditions facing the hydrogen sector today differ significantly from those that characterised the EU gas sector at the time of liberalisation. Hydrogen markets remain at an early stage of development, with limited current demand, uncertain prospects for future growth, and only a nascent infrastructure base. These differences introduce specific challenges for applying the EU gas regulatory model to hydrogen, as discussed in Section 5.1.

Section 5.2 then outlines an alternative regulatory model, presenting the attributes and market conditions under which a lighter, more market-driven approach may be more appropriate for the hydrogen sector's development.

[71] See the German Decision on the setting of network tariffs to be charged for access to the hydrogen core network and on the establishment of a payback mechanism effective for a certain period, WANDA (link).

[72] See: Stratégie nationale de l'hydrogène décarboné, April 2025 (link).

5.1. Extension of the EU Gas Network Model to Hydrogen

The EU's Hydrogen and Decarbonised Gas Market package, comprising Directive (EU) 2024/1788 and Regulation (EU) 2024/1789, establishes comprehensive rules for third-party access (TPA) to hydrogen networks.

As of 1 January 2033, hydrogen network operators are required to provide regulated third-party access, as stipulated in Article 7 of Regulation (EU) 2024/1789. This comprises the use of an E/E model (Article 7(6) of Regulation (EU) 2024/1789) and the application of tariffs (Article 7(8) and 9 of Regulation (EU) 2024/1789), which can be removed at IPs. The negotiated TPA can be used until 31 December 2032 as a transitional measure before applying the regulated TPA, as stated in Article 35(4) of Directive (EU) 2024/1788.

Article 7(3) of Regulation (EU) 2024/1789 further limits the duration of contracts to 20 years for infrastructure completed before 1 January 2028 and 15 years for infrastructure completed on or after that date.

Regulation (EU) 2024/1789 foresees the possibility of derogating hydrogen infrastructure from TPA requirements for an indefinite period, subject to specific conditions, in the cases of existing hydrogen infrastructure,[73] with geographically confined hydrogen networks.[74] In addition, Regulation (EU) 2024/1789 foresees the possibility of applying exemptions to major new natural gas infrastructure (including IPs) from TPA rules subject to the EC's approval.

This regulatory framework reflects a conscious policy decision to extend the EU gas market model to hydrogen, embedding the core principles of unbundled infrastructure, regulated access, and network-based service provision into the hydrogen transport sector.

Despite the regulatory continuity with the gas sector, the early-stage nature of the hydrogen market introduces specific challenges regarding demand uncertainty, infrastructure investment risks, and cost recovery, which differ fundamentally from the context of EU gas market liberalisation. Unlike the gas sector, built on an already established and extensively amortised infrastructure base supported by long-term commodity contracts, the hydrogen sector must simultaneously stimulate commodity demand, finance new infrastructure, and manage significant uncertainties about future market growth.

The early stage of hydrogen infrastructure development faces the fundamental challenge of mitigating the volume risk. As discussed in this section, mitigating the price risk (i.e.,

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[73] According to Article 51 of Regulation (EU) 2024/1789, Member States may provide for regulatory authorities to grant a derogation from the TPA requirements in Articles 7 of Regulation (EU) 2024/1789 to hydrogen networks that belonged to a vertically integrated undertaking on 4 August 2024.

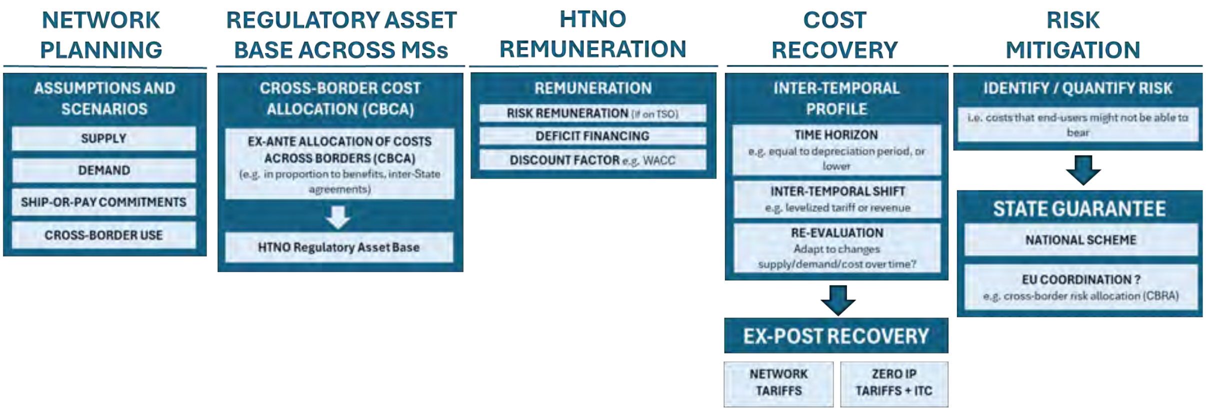
[74] According to Article 52 of Regulation (EU) 2024/1789, Member States may provide for regulatory authorities to grant a derogation from the TPA requirements in Articles 7 of Regulation (EU) 2024/1789 to hydrogen networks which transport hydrogen within a geographically confined, industrial or commercial area.

ensuring the competitiveness of the commodity) is a pre-condition for the market to mitigate the volume risk of the infrastructure.

As discussed in Sections 3.2 and 4.2, the EU and US gas sectors were developed around vertical integration. Section 2.2 discusses how vertical integration and long-term contracts are necessary to limit the risk of opportunistic behaviour or hold-up and to mitigate the volume risk associated with the infrastructure, ensuring the recovery of the investment. In liberalised markets where unbundling applies to the transport segment, vertical integration is no longer possible, leaving long-term contracts and state guarantees as the primary options for developing infrastructure.

The overall planning of hydrogen infrastructure will require several steps, including network planning, establishing the hydrogen transmission network operators (HTNOs), including for projects across borders, setting the allowed revenue of HTNOS, and establishing the rules for cost recovery (typically network tariffs), as well as the instruments for risk mitigation. These elements are represented in Figure 8 below. The section focuses on the differences between cost recovery and risk mitigation in hydrogen networks compared to EU natural gas networks.

Figure 8: Hydrogen infrastructure: from network planning to cost recovery.



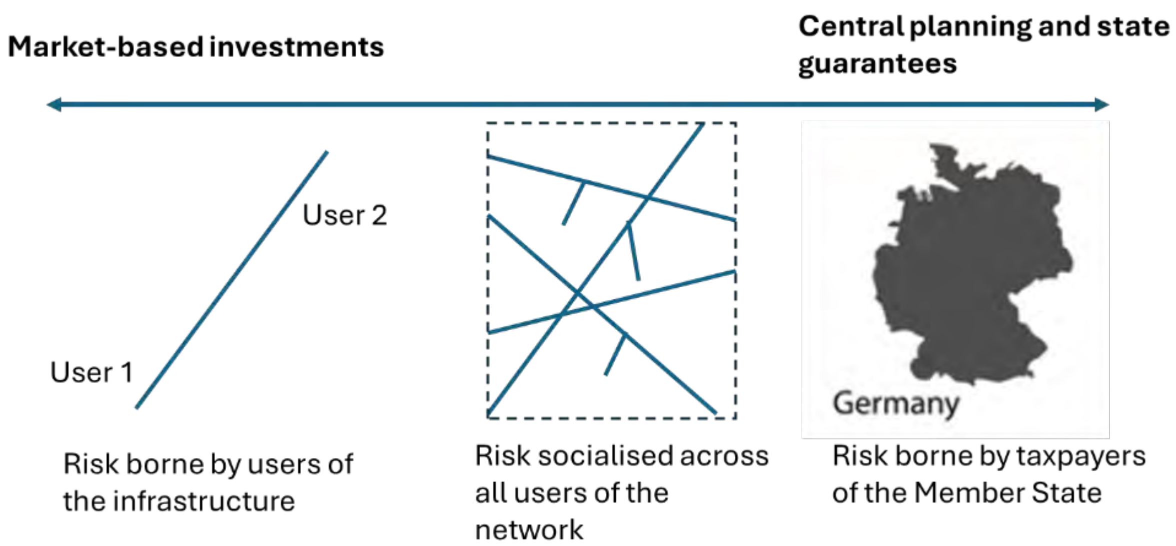
5.1.1. Cost recovery and risk mitigation in E/E networks

In the EU-regulated E/E gas networks, LTCs for the commodity, established at competitive price levels, support LTCs for the infrastructure capacity, guaranteeing the recovery of infrastructure costs. Following the introduction of the E/E networks, these guarantees for the recovery of infrastructure costs are provided by the allowed revenue of the hydrogen transmission network operators (HTNOs). NRAs establish a guarantee of revenue recovery for the network costs, which is ultimately provided by end-users of the network, as discussed in Section 4.4 above. This guarantee of repayment is sufficient for banks to provide credit to HTNOs to finance new infrastructure. In the case of Germany, it has been a standard practice for banks to provide credit for up to 100 per cent of the regulated asset base (RAB) of the TSO.[75] This assumes that existing users will underwrite the existing RAB and can absorb increases of up to 100 per cent of the RAB over time.

Given the uncertainty surrounding how demand could develop, this financing model is no longer valid for hydrogen. Anticipatory hydrogen investments built for future users face the risk that demand may not grow as forecasted, resulting in a smaller user base to recover infrastructure investment. As a result, infrastructure cannot be built by socialising the infrastructure risks to all network users, as it is currently done for gas. In this situation, the only possible guarantees for developing infrastructure can come from states or other financial institutions.[76] This requires expanding the user base to mitigate the risk of building infrastructure using state budget funds.

This results in the sequence in Figure 9 below, showing how a more extensive user base bears the infrastructure risk. The figure to the left shows investments where the infrastructure risk is borne by the individual users financing the incremental capacity; this is the case in the US gas market. The central figure represents the case of the EU gas market, where all network users bear the infrastructure risk. Finally, the figure to the right shows the case of hydrogen in the EU, where the state bears the infrastructure risk. The approach adopted in the early stages of the EU hydrogen market represents a move away from market-based instruments for infrastructure investments.

Figure 9: Spectrum of risk mitigation instruments. Market-based investment and central planning.



As discussed in Section 4.3, tariffs for E/E networks in the EU are used to recover the allowed revenue of the TSO. The NRA sets both the allowed revenue of the TSOs and the tariffs. In this context, tariffs for natural gas transmission networks serve two functions:

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[75] Reference provided by staff of a German bank taking part in financing activity with TSOs which has requested to remain confidential. The practice is, nevertheless, standard across Germany.
[76] Other options could be implemented following Article 5(4) of Regulation (EU) 2024/1789, such as cross-sector financial transfers between the electricity and gas sectors, on the one side, and the hydrogen sector, on the other. These tool could trigger opposition from users of natural gas and electricity not supportive of financing hydrogen networks.

first, they enable the recovery of network costs; second, they facilitate the extension of cost recovery until the full investment costs have been recouped. As the sector matures, the continued charging of tariffs is expected to recover the full costs of the network investments. End-users of the network ensure that the costs of the TSO are recovered, but in practice, this guarantee mitigates the risk associated with infrastructure investments by implementing transmission tariffs.

In the context of hydrogen, there is a decoupling of these two functions: tariffs can serve to recover network costs, but they no longer ensure the full recovery of network investments. This is because there is an insufficient user base that can guarantee a sufficient level of utilisation to recover the entire investment of the TSO.

5.1.2. Risk mitigation for hydrogen infrastructure

The development of hydrogen infrastructure in the early stages of the sector requires instruments beyond the traditional regulatory tools used to mitigate the risk associated with the full recovery of investment costs (i.e. network tariffs). In 2024 and 2025, Germany and Denmark approved tools for this purpose, with several other Members States discussing additional options.

The mechanisms designed for this purpose fall under Article 5 of Regulation (EU) 2024/1789, which foresees the implementation of inter-temporal cost allocation mechanisms to decrease network tariffs in the early stages of the sector and mitigate the risk associated with recovering the infrastructure costs.[77]

In the case of Germany, an amortisation account was approved in October 2024,[78] allowing for the financing of revenue recovery in the early stages with debt that is repaid over time. The hydrogen network is expected to costs €18.9bn and is expected to be build by between 2032 and 2037 depending on the evolution of demand. In the case that infrastructure users do not recover the full investment costs by 2055, the German State guarantees 76 per cent of the costs not recovered by that date, with the remaining 24 per cent of the risk being borne by HTNOs. In return, HTNOs receive a 6.69 per cent rate of return, which can be revised by 2028. Under this mechanism, cost recovery is minimised in the early phase by postponing the revenue recovery to later stages where demand is expected to be higher. For this purpose, a debt instrument implemented by the public development bank KfW is used, which partially subsidises the costs of debt as no margins are made on the interest rate. Finally, the amortisation account has been assessed in various reports which look at the risk associated with different parameters, such as the repayment time, the demand development pace and the development of

[77] See Recital 10 of Regulation (EU) 2024/1789.

[78] Determination proceedings by the Grand Ruling Chamber for Energy on "Provisions for calculating the network tariffs chargeable for access to the hydrogen core network and for establishing a payback mechanism effective for a certain period (WANDA)" [GBK-24-01-2#1]. For more information see BNetzA's website (link). See also the Document Accompanying the determination for the financing of the hydrogen core network, WANDA (link).

hydrogen production costs (Fraunhofer IEG et al., 2024; Fraunhofer IEG & Fraunhofer ISI, 2025).

In the case of Denmark, the Danish Parliament passed legislation on 6 February 2025 to support the development of the hydrogen network with a budget of DKK 8.3 billion (approximately € 1.1 billion) over a period of 30 years.[79] This support requires a minimum of 0.5 GWh of ship-or-pay yearly bookings from the market for at least 10 years, with the capacity expected to be offered in an open season planned in 2026. The provision of state support for the development of the network will complement and inter-temporal cost-allocation mechanism which shifts a part of the revenue recovery to future users. This mechanism is planned for 30 years allowing for the adaptation of the different parameters over time to adapt to the demand development pace and other factors.

In general, these mechanisms serve two distinct purposes, first they allow reducing the costs for users in the early development phase, and second, they allow recovering the full investment costs (i.e. mitigating the volume risk). Regarding the first objective, the reduction of cost-recovery (hence, tariffs), in the early stages can be achieved through various instruments.

The first option is the provision of **direct support**, which reduces the costs borne by network users, hence the tariffs. Support can be provided during the initial phase or across the full life of the assets. Figure 10 shows how direct support can reduce the share of the RAB to be recovered. In the figure, the reduction is applied across the lifetime of the assets. Figure 11 depict the impact on tariffs which are reduced as a result of the lower cost to recover.

A second option is based on the **depreciation profile**. Instead of the standard straight-line depreciation used for natural gas infrastructure, hydrogen projects can be based on accelerated depreciation, which adapts the recovery of costs to the increasing demand forecast, delaying cost recovery. Figure 12 provides the same demand curve that increases over time. Figure 13 represents a straight line and an accelerated depreciation, the latter postponing the recovery of costs. Finally, Figure 14 represents the impact on tariffs of both, a straight line and an accelerated depreciation. Importantly, the latter allows to postpone the recovery of costs.

A third option can achieve the same result, although using an **amortisation account**. The RAB is depreciated using straight-line depreciation, which allows the TSO to recover the yearly allowed revenue based on a standard depreciation profile. Tariffs, however, only recover a part of the costs, with the remaining revenue being transferred to debt instrument or amortisation account. There are different approaches to recover this debt.

- One option is to establish a **fixed tariff or affordable tariff over time**. Such tariff will be lower than the corresponding tariff in the early phase, but higher than the

[79] See the *Hydrogen Infrastructure to Germany: Enabling the "Seven" (Syvtallet) Follow-up on the 1st partial agreement on ownership and operation of pipeline-based hydrogen infrastructure, as well as the 2nd partial agreement on the economic framework conditions for hydrogen infrastructure* [link].

corresponding tariffs resulting from higher demand levels. This is represented in Figure 16, which shows in orange the fixed tariff or affordable tariff. Figure 17 shows the resulting deficit in the early phase (blue area) and the accumulated debt (curve in green). During the second phase (orange area), the over-recovery is used to repay the accumulated debt.

- An alternative mechanism can be implemented as a **capacity mechanism.** Tariff can be calculated based on optimal utilisation levels of the network, which will only be achieved in the future. The lower capacity bookings in the early stage of the market development can be registered into an amortisation account to be repaid by future users (see Figure 19, Figure 20 and Figure 21 below). Alternatively, these costs can be subsidised by government support. Both the fixed tariff and the capacity mechanism serve to achieve the same purpose, however, they do it using a different instrument. On the one case, revenue recovery is calculated on the basis of a fixed tariff levels over time, while on the other revenue recovery is calculated on the basis of capacity sales. These alternative approaches are possible as the revenue is ultimately the result of capacity sales based on the applicable tariff.

Options two and three are equivalent and only differ in the party responsible for financing the non-recovered revenue. Under option two, debt is financed by the market (i.e. by HTNOs) by applying an accelerated depreciation. Under option three, the initial under-recovery can be financed publicly.

Figure 10: Direct support to RAB (EUR) and increasing demand forecast (TWh/year)

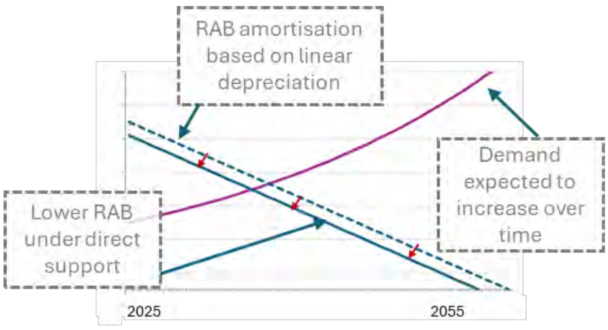


Figure 11: Tariffs resulting from direct support to RAB (€/MWh/d/Y) and increasing demand forecast (TWh/year)

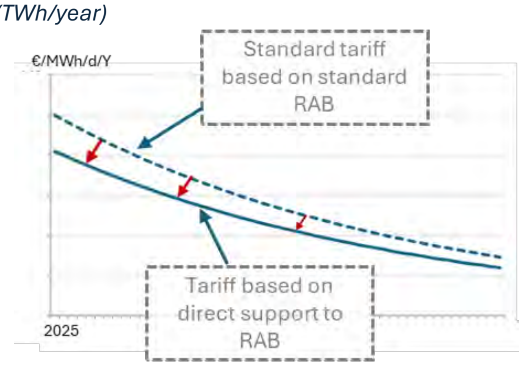


Figure 12: Increasing demand forecast (TWh/year)

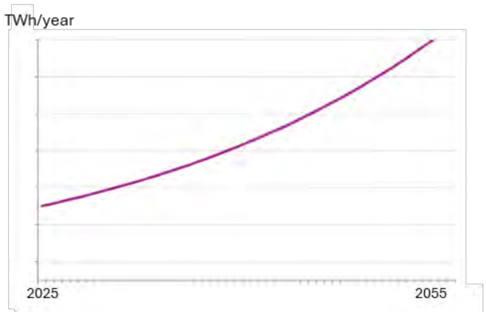


Figure 13: Straight line depreciation and accelerated depreciation, in percentage.

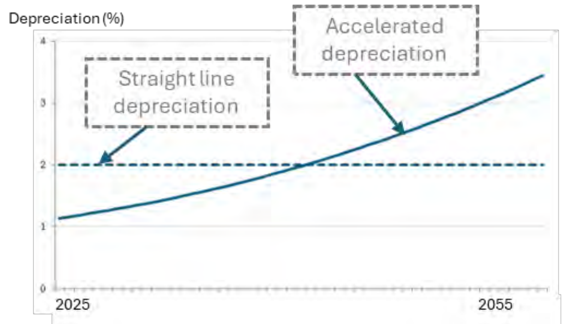
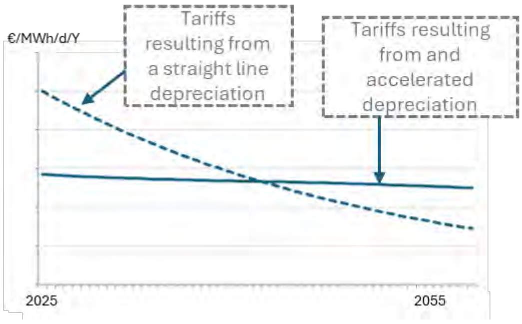


Figure 14: Tariffs resulting from straight line depreciation and accelerated depreciation (TWh/year)



The second distinct feature enabled by the inter-temporal cost allocation mechanisms is the **recovery of the full investment**. This function can be implemented using two different approaches.

- A **guarantee on the allowed revenue of the TSO can be implemented at the end of a period**. For example, if the investment costs of a network have not been recovered by the time the investments have been fully depreciated, a guarantee by the state can be actioned to recover these costs.
- A **guarantee on the capacity offered by the TSO can be implemented year-on-year**. This instrument is similar to the capacity mechanisms described above. When used over a limited period of time, it can reduce the revenue recovery (hence the resulting tariffs) over the early development phase. However, if used continuously until the end full depreciation of the network assets, the instrument ensures the repayment of all the capacity offered. This allows to recover the full allowed revenue of the HTNO.

These instruments can be combined. The German amortisation account is used to shift costs across time while guaranteeing cost recovery by 2055. The functioning is summarised in Figure 15, Figure 16, Figure 17. The German state provides a guarantee of cost recovery applicable in 2055 for the revenue that has not been recovered by that date. In the initial phase, standard tariffs would have very high levels resulting from the high investment costs and low demand (see Figure 15). The resulting tariff levels are represented in blue in Figure 16. The German inter-temporal mechanism proposes an alternative 'affordable' tariff at lower levels (represented in orange in Figure 16), which would result in an under-recovery in the early stages (blue area represented in Figure 17), which is compensated with an over-recovery in the later stages (the orange area represented in Figure 17). This initial under-recovery is financed with debt and is repaid with the later over-recovery.

Figure 15: Allowed revenue (EUR) and forecasted increasing demand (TWh/year)

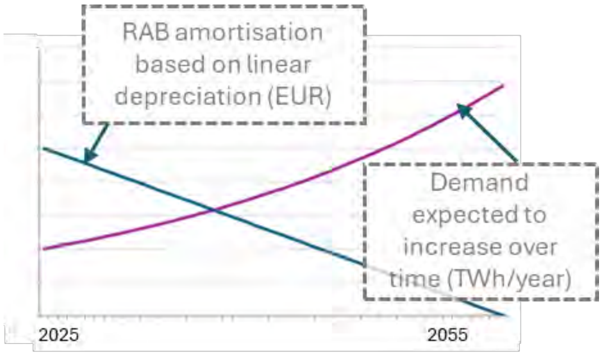


Figure 16: Tariffs resulting from standard allowed revenue and affordable tariffs (€/MWh/d/Y).

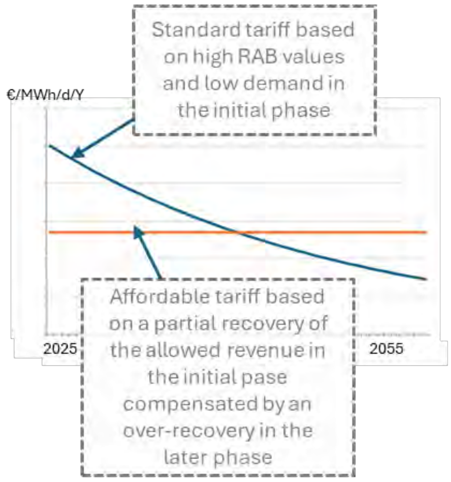


Figure 17: Under-recovery in the initial stages, over-recovery in the later stages and deficit repayment (EUR).

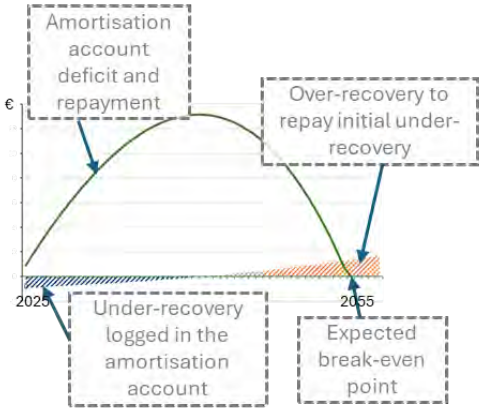
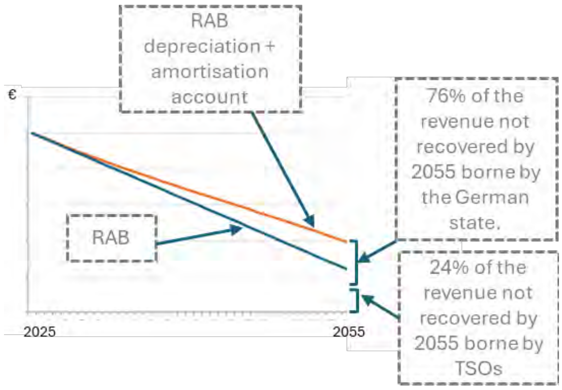


Figure 18: Risk sharing for the German amortisation account by 2055 (EUR and percentages)



The accumulated under-recovery and its payment are represented as a green line in Figure 17 and Figure 18. The green line in Figure 17 shows how the debt increases in the early phases until it is completely paid off when the green line crosses the x-axis. In comparison, Figure 18 provides an example of where the accumulated debt has not been fully recovered.

The intertemporal cost-allocation mechanism, which shifts costs to future users of the networks, can be combined with direct support from the state, which lowers tariff levels.

An alternative approach to using guarantees to recover the allowed revenue are capacity guarantees or capacity commitments. Under this approach, the state can guarantee the capacity offered by the TSO, ensuring that it falls between the minimum capacity requirement established for the market and the total capacity bookings that enable the full recovery of the annual TSO-allowed revenue. This is represented in Figure 19 below, which shows the minimum capacity requirements for the market and the capacity levels guaranteed by the state. As demand increases over time, market bookings are expected to rise, as shown in Figure 20 below. Figure 21 below illustrates how the increase in network utilisation over time enables market bookings to rise (light blue area) above the established minimum ship-or-pay commitments (dark blue area). This allows the state's capacity commitments to be reduced over time (light orange area).

Figure 19: Technical capacity and minimum ship-or-pay commitments from the market (MWh/d/Y).

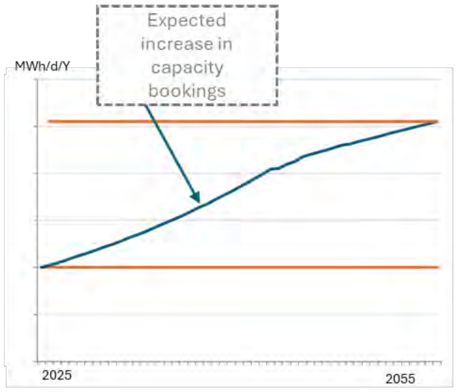


Figure 20: Technical capacity, minimum ship-or-pay capacity and increasing capacity utilisation (MWh/d/Y)

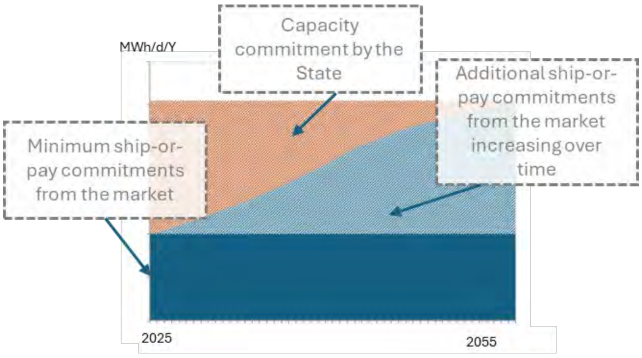


Figure 21: Capacity mechanism / guarantee (MWh/d/Y).

While these mechanisms address the volume risk of the infrastructure, it should be noted that mitigating the volume risk, also known as the hold-up risk or opportunistic behaviour, requires, first and foremost, mitigating the price risk of the commodity, that is, ensuring the competitiveness of the commodity. As discussed in Section 4.1, the European long-term contracts (LTCs) for the commodity had two risk mitigation instruments addressing price and volume risk. Ultimately, the volume risk of natural gas pipelines was only mitigated because the commodity remained competitive based on netback oil indexation. Mitigating price risk is a precondition for mitigating volume risk. Without a competitive commodity, off-takers will not be willing to support long-term ship-or-pay contracts to mitigate the volume risk. In these circumstances, state infrastructure financing and subsidising the commodity remains the only option in the immature phase of hydrogen market development. Furthermore, there are instruments, such as subsidies through European Hydrogen Bank auctions and H2Global, that aim to de-risk (green) hydrogen and its derivatives, including ammonia, methanol, and sustainable aviation fuel.

5.1.3. Cross-border cost and risk allocation

The mechanisms discussed above are based on the provision of state guarantees or state support at a national level. However, hydrogen infrastructure development could include pipelines crossing Member States, such as natural gas pipelines transporting gas across the EU. These pipelines would face similar risks when recovering the investment costs described above. However, in addition to the risk associated with the development of demand, these routes would face competition with other routes that could emerge. Given that these pipelines are intended to supply specific markets across the EU (e.g., Germany), there is an open question about mitigating the risk associated with infrastructure crossing multiple Member States.

Without cross-border guarantees, each network would have to bear the risk associated with the relevant section of the project. However, each Member State along the project path might not be willing to guarantee the costs intended to supply a third country. Mitigating the risk associated with cross-border infrastructure will likely require inter-governmental coordination to establish guarantees across borders. The EU toolbox includes the cross-border cost allocation mechanism (CBCA), referred to in Section 4.4.1 above. However, this tool is intended to allocate costs later recovered via tariffs. The CBCA is not intended to provide state guarantees for investments. The CBCA, nevertheless, provides a model that can be useful for developing cross-border guarantees. The CBCA is designed to distribute the costs of a cross-border project across different networks in proportion to the benefits they receive. Where a network benefits from a cross-border project, the share of costs the network bears should be proportional to these benefits. The allocation is based on cross-border risk allocation mechanisms (CBRA), which distribute the risk of cross-border projects across multiple Member States.

Figure 22, Figure 23 and Figure 24 illustrate how cross-border guarantees could be established for infrastructure crossing multiple networks. Figure 22 represents an example of a pipeline crossing three networks, expanding from network A, where production is located, to network C, where 70 per cent of the hydrogen is transported. Network B is a transit network with a 30 per cent offtake.

The guarantees for this simple example can be established based on capacity or allowed revenue commitments. The former is illustrated in Figure 23. The capacity commitments in Figure 21 are borne by a single state (orange area) or can be shared between two states in Figure 23. This can be done in proportion to the benefits, following the CBCA logic, or in proportion to another indicator, such as the expected use of capacity for transit purposes. The area in orange represents a capacity commitment for 70 per cent of the capacity above the market ship-or-pay commitments.

Figure 24 illustrates a similar instrument implemented based on allowed revenue commitments, in line with Figure 15, Figure 16, Figure 17 and Figure 18. The allowed revenue associated with the transit segment across network C is guaranteed by networks B (for 70 per cent of the costs) and C (for 30 per cent of the costs).

Figure 22: Example of an infrastructure corridor connecting three different Member States

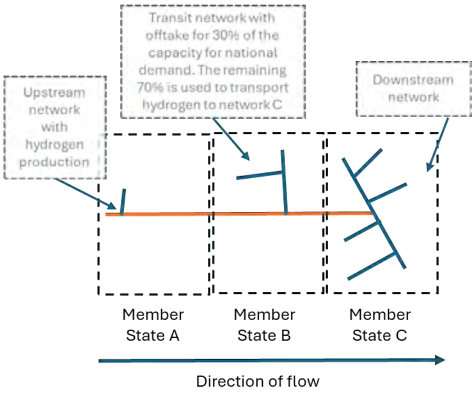


Figure 23: Example of capacity commitments for the pipeline capacity in network B, provided by Member States B and C (MWh/d/Y)

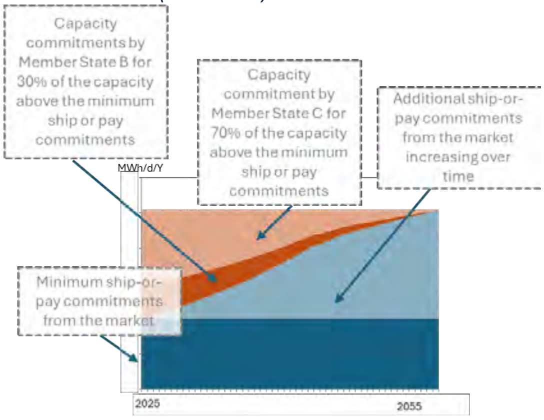
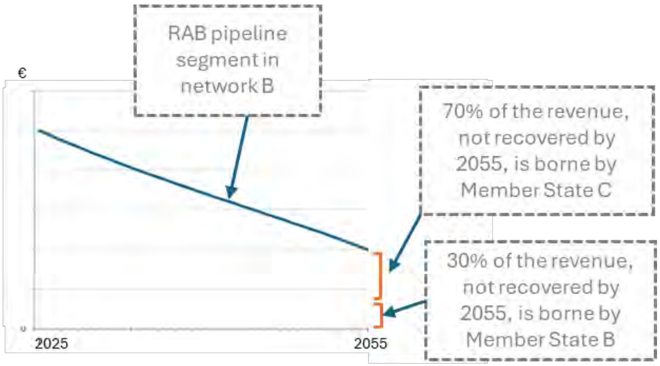


Figure 24: Example of revenue guarantees for the pipeline segment in network B provided by Member State B and C by 2055 (EUR).



5.2. Alternative Market Design Option

As outlined in Section 5.1, the regulatory framework for hydrogen transport in the European Union is largely based on extending principles from the natural gas market, including the use of regulated third-party access (TPA) and an entry-exit (E/E) model. However, the structural conditions shaping the hydrogen sector differ significantly from those that characterised the gas sector at the time of liberalisation. These differences suggest that an alternative regulatory approach – based on pipeline-level regulation, negotiated access, and decentralised market coordination – may be more appropriate in the longer term.

Inspired by the United States natural gas sector, this alternative market design emphasises contractual arrangements, infrastructure development driven by market signals, and minimal centralised intervention. Under this model, individual pipelines negotiate access terms with users, investments are supported through long-term capacity bookings, and market platforms enable capacity trading, offering greater flexibility and responsiveness to evolving market needs.

The appropriateness of extending the EU model or transitioning towards a US-inspired model depends critically on the evolution of specific market attributes. Table 5 summarises the key factors influencing the regulatory choice between these two approaches. The subsequent sections examine each attribute in greater detail.

Table 5: Attributes Influencing the Choice Between Hydrogen Pipeline Regulatory Models

	Factors supporting the extension of a EU Model based on regulated TPA and network-wide regulation	Factors supporting convergence towards the US Model natural gas market design based on pipeline-level regulation and market coordination
Geographical distribution of production	Concentrated production sites	Decentralised, geographically dispersed production
Market concentration in production	High concentration (risk of foreclosure)	Low concentration (competitive production landscape)
Importance of retail competition	High retail competition (need for liquidity and standardisation)	Predominantly large customers with bilateral contracting
Liquidity barriers	High (high market concentration, barriers to access)	Low (low market concentration, limited barriers to access)
Network planning	Mature, non-expanding demand, credible off-take commitments, where investment needs are limited.	Greenfields, increasing but uncertain demand, early-stage market where locational signals are relevant.
Expected role of hydrogen in the energy system	Widespread use across sectors (residential, industrial, power generation)	Niche applications, limited sectoral penetration

5.2.1. Concentration in hydrogen markets

The EU natural gas sector was developed based on national monopolies and long-term contracts with limited suppliers outside the EU. Contracts for the commodity required the development of dedicated upstream projects and using long-distance pipelines, resulting in significant fixed costs. At the time of liberalisation, this structure proved persistent, possibly leading to market foreclosure and market abuse. This situation was seen as justifying the application of regulated TPA at the network level.

In comparison, the production of green hydrogen is not limited to specific locations and is subject to significantly lower fixed costs. Both elements limit the possibility of upstream concentration and the formation of monopolies. In the case of electrolysers, fixed costs represent a much lower share of the total costs, with electricity production accounting for the remaining costs (IRENA, 2020). The renewable electricity generation required to produce green hydrogen does not support a highly concentrated hydrogen production market.

Regulating networks as essential facilities necessary for the development of competition may be less critical in the absence of the expected concentration levels. This was the basis for the application in the EU gas market. The Bronner case in US case law argued that "*the most economic route should not be considered as an essential facility where other routes exist, though less economic*" (Talus, 2011). From this perspective, the US natural gas market offers an alternative model that is more closely aligned with the mature green hydrogen market in the EU. These assets can compete across routes to connect supply and demand centres by applying a negotiated TPA regime to individual hydrogen pipelines. This is, in essence, the US market model.

5.2.2. Locational distribution of hydrogen production

The geographical distribution of hydrogen production is another critical attribute influencing the appropriate regulatory model. In the natural gas sector, upstream production was typically concentrated around a few major suppliers, with Europe's gas imports largely dependent on limited external sources and dedicated long-distance pipelines. This concentration justified the development of extensive regulated networks to ensure access and prevent monopolistic bottlenecks.

By contrast, the production of green hydrogen is expected to exhibit significantly greater locational flexibility. Optimal hydrogen production sites will depend mainly on the availability of low-cost renewable electricity, particularly locations with high annual operating hours for solar and wind energy generation. This technological characteristic enables producers to site electrolysers across a wide geographical area, depending on resource availability, land use constraints, and proximity to demand centres.

This decentralised pattern of hydrogen production supports a market model in which multiple supply nodes compete to serve diverse demand locations. Pipelines in this setting would compete to transport hydrogen from a distributed production landscape to end users. The resulting market structure resembles the upstream segment of the US natural gas market, where production and demand points are distributed across vast territories, and pipeline competition is a critical feature of market coordination.

Such a configuration reduces the likelihood that any single pipeline or network would attain bottleneck control over the market. Multiple routes and suppliers provide natural redundancy and competitive pressures, undermining the case for classifying pipelines as essential facilities requiring comprehensively regulated access obligations. Applying a lighter regulatory regime based on negotiated TPA at the pipeline level, as in the US model, would better support efficient market development by enabling producers and users to align infrastructure access terms with specific market needs.

However, it is crucial to recognise that the spatial economics of hydrogen production are likely to evolve. In the early phases of green hydrogen development, regulatory requirements imposed by the Renewable Fuels of Non-Biological Origin (RFNBO) delegated act – specifically, the pillars of hourly matching, additionality, and geographical correlation – necessitate an islanded production model. Under this framework, electrolysers must be closely co-located with dedicated renewable generation assets, reinforcing strong locational signals and supporting a decentralised production structure. These conditions align closely with the assumptions underpinning a pipeline-level regulatory model based on negotiated third-party access.

However, as the European electricity grid decarbonises and green hydrogen production technologies mature, these facilities are increasingly expected to be connected directly to the transmission grid. In this future phase, the spatial differentiation in electricity prices across large bidding zones will weaken, reducing the strength of locational signals for siting hydrogen production. Consequently, the decentralised and competitive production structure observed in the early market phases may give way to a more homogenised supply landscape. This potential evolution reinforces the need for regulatory flexibility, allowing the market design to adapt dynamically to changing technological and market conditions over time.

5.2.3. Relevance of retail competition

In the early phases of the sector, infrastructure can be developed with state guarantees. Still, in the mature phase, it can rely on long-term contracts (LTCs) developed for the commodity, which support pipeline infrastructure development.

Compared to the EU natural gas sector, retail competition is expected to have lower relevance in the hydrogen sector, where most demand comes from industry. To transition to green hydrogen, industrial end-consumers must invest in CAPEX-intensive and site-specific assets. According to transaction costs economics, these investments require long-term contracts which can underpin the commodity and support infrastructure development. In the case of the EU, implementing competition at the retail level has significantly limited suppliers' ability to enter into long-term contracts with producers that would support the financing of incremental capacity. For this reason, the socialisation of investments in the context of regulated networks was a response to the introduction of retail competition. As in the US gas market, demand for infrastructure can be aggregated to support the financing of dedicated supply infrastructure.

This characterisation approximates the EU hydrogen market to the US market, where some consumers are held captive by regulated retail suppliers. This model has enabled competition between producers to supply regulated customers and competition between pipelines to enable access to these markets. In the case of the EU hydrogen market, the highly specific investments of industrial consumers and the lower specificity of hydrogen generation support a market design where producers and pipelines compete to gain access to hydrogen end-users under long-term contracts.

5.2.4. Barriers to liquidity

Liquidity barriers represent another essential dimension in assessing the suitability of alternative regulatory frameworks for hydrogen infrastructure. In liberalising the European natural gas sector, concerns about limited market liquidity justified the adoption of extensive regulatory measures, including creating virtual trading hubs and socialising infrastructure costs across wide network areas. These interventions were necessary because natural gas production was highly capital-intensive, associated with significant sunk costs, and geographically concentrated. New entrants faced high barriers to accessing upstream production and transportation infrastructure, justifying regulatory efforts to foster liquidity through extensive third-party access (TPA) obligations at the network level.

In the case of green hydrogen, however, the production landscape differs fundamentally. The capital requirements for deploying electrolysers are considerably lower than those for developing upstream gas production projects, and renewable electricity – the primary input into green hydrogen production – is increasingly decentralised. These factors significantly reduce entry barriers for new hydrogen producers, lowering the threshold for market participation.

With lower fixed costs and a broader base of potential entrants, the need for extensive network-level liquidity facilitation measures is diminished. While liquidity remains an essential consideration for market development, particularly in ensuring price discovery and efficient matching of supply and demand, the fundamental barriers to liquidity in the hydrogen sector are likely lower than in the historical gas sector.

Moreover, applying a highly regulated, network-wide model similar to that used in the gas sector could introduce inefficiencies in the hydrogen market. Infrastructure developed on a pre-emptive, network-wide basis would involve significant capital expenditures, which must be recovered through network tariffs. In a sector where achieving commodity price competitiveness is a critical objective for market growth, imposing additional infrastructure costs on early users could undermine the commercial viability of green hydrogen.

From this perspective, a light-touch regulation at the level of individual pipelines, rather than across entire networks, may be preferable. Such an approach would allow for more efficient allocation of infrastructure costs, directly linking investment decisions to actual market demand and reducing unnecessary capital expenditures. By aligning cost recovery more closely with infrastructure usage, a pipeline-level regulatory model would support liquidity growth organically as the market expands while preserving cost efficiency and minimising barriers to early adoption.

5.2.5. Network planning

The approach to network planning constitutes another critical factor in evaluating the appropriate regulatory framework for hydrogen transport infrastructure. In the European natural gas sector, the introduction of regulated entry-exit (E/E) networks and the development of liquid virtual hubs facilitated market liberalisation by creating large, standardised trading zones. Uniform transport tariffs were applied within these zones, and network planning responsibilities were centralised to ensure coordinated infrastructure expansion. While effective in promoting short-term competition and liquidity, this model dampened locational investment signals and weakened the link between infrastructure usage and cost causality.

In the hydrogen sector, the stakes associated with network planning are even higher. Infrastructure development will be central in determining the pace and direction of hydrogen market expansion. In contrast to the liberalisation phase of the gas sector, where networks were already largely built, hydrogen infrastructure must be developed from scratch. Accordingly, the quality of investment signals and the efficiency of network development are of even greater importance in avoiding stranded assets and supporting the sector's growth.

While facilitating liquidity and non-discriminatory access, a market design based on regulated networks risks impairing dynamic efficiency by socialising investment decisions across vast areas and weakening the incentives for incremental, market-driven infrastructure development. In particular, uniform tariffs across large zones may obscure the real cost differentials of transporting hydrogen across varying distances and geographies, thereby misallocating investment and operational costs.

This concern is particularly relevant given the competitive pressures hydrogen will face from alternative decarbonisation vectors such as direct electrification and renewable gases. Without granular investment signals reflecting network expansion and operation costs, hydrogen infrastructure may struggle to compete efficiently against other low-carbon energy solutions. Misaligned price signals could lead to overinvestment, underutilisation, and inefficient allocation of capital, ultimately undermining the economic competitiveness of hydrogen as an energy carrier.

Applying regulation at the level of individual assets - pipelines, storage facilities, and import terminals – rather than across entire networks could mitigate these risks. A pipeline-level regulatory approach would preserve more accurate investment signals, closely tying infrastructure development to actual market needs. It would also complement long-term commodity contracts to underpin infrastructure financing, aligning infrastructure expansion with genuine demand growth rather than administrative projections.

In this respect, the regulatory model employed in the US natural gas market offers a valuable reference. The US model has maintained a higher degree of dynamic efficiency by regulating infrastructure at the asset level and allowing market participants to coordinate investments through long-term contractual arrangements. Such an approach may be particularly well-suited to the hydrogen sector, where infrastructure needs are still highly uncertain, and the flexibility to adapt to evolving market conditions is essential.

5.3. Expected Role of Hydrogen in the Energy System

The expected role of hydrogen within the broader energy system represents a final critical factor influencing the appropriate regulatory model. The scope and nature of hydrogen demand will fundamentally shape infrastructure development needs, investment risks, and the trade-offs between different forms of regulatory intervention.

Based on current market expectations (as discussed in Sections 5.2.1 – 5.2.5), hydrogen will likely remain concentrated in niche applications in the medium term. Demand is expected to originate primarily from industrial uses such as high-temperature processes, chemical feedstocks, and specific transport segments rather than achieving widespread penetration across residential, commercial, and power generation sectors. In this context, developing an extensive, integrated hydrogen network ahead of demand would entail significant investment risks, with a high likelihood of stranded assets and underutilised infrastructure. A regulatory model based on negotiated third-party access (TPA) at the pipeline level, aligned with the US approach, offers a more appropriate framework under these conditions. It allows infrastructure development to respond incrementally to actual market signals, preserves dynamic efficiency, and minimises public exposure to investment risks.

Moreover, the early phase of green hydrogen development is characterised by strong locational signals due to regulatory requirements on additionality, hourly matching, and geographical correlation under the Renewable Fuels of Non-Biological Origin (RFNBO) delegated act. These conditions reinforce decentralised production and align naturally with a market-driven, asset-level regulatory approach.

Notably, the EU's Hydrogen and Decarbonised Gas Market package allows for negotiated TPA as a transitional arrangement until the end of 2032, implicitly recognising that a market-led, contractual approach is appropriate for the early stages of hydrogen market development. However, as discussed in Section 5.1, emerging regulatory and investment practices at the Member State level tend towards pre-emptive large-scale infrastructure development supported by substantial public guarantees. While such anticipatory investments may seek to catalyse hydrogen market growth, they also introduce significant risks of overbuilding and stranded assets.

Given these risks, starting with a negotiated TPA model – aligned with the US regulatory approach – represents a no-regret option. It allows infrastructure development to be more closely tied to actual market needs, preserves optionality for future regulatory evolution, and mitigates the risk of dynamic inefficiencies associated with premature network construction. Should market foreclosure and barriers to liquidity develop, the regulatory framework can adopt measures based on observed market conditions rather than ex-ante assumptions, which may include network-wide coordination.

Nonetheless, the long-term evolution of the hydrogen sector remains uncertain. Should hydrogen unexpectedly expand into widespread use across residential heating, power generation, and commercial sectors – becoming a dominant energy carrier comparable to the role of natural gas in the twentieth century – the regulatory framework can consider adaptations. In such a scenario, broader network-wide regulation could be considered to enhance liquidity, facilitate non-discriminatory access, and support large-scale market expansion. It should be noted that the US regulatory framework allows serving natural gas demand for a multiplicity of users. Hence, the application of negotiated TPA is not limited to niche markets.

Maintaining early regulatory flexibility is, therefore, essential. Starting with a decentralised, market-coordinated approach provides a pragmatic strategy: it preserves the option to evolve toward network-wide coordination if justified by future market developments while mitigating the immediate risks associated with premature, large-scale infrastructure investment.

Prematurely mandating network-wide regulated access risks institutional lock-in, making future adaptation difficult. Institutional economics highlights how early regulatory choices can shape long-term market structures through path dependency (North, 1990; Pierson, 2000). Once regulatory institutions, administrative procedures, and financial frameworks – particularly around network-wide regulated TPA – are established, they tend to create powerful vested interests resistant to change (Levi-Faur, 2005).

As capital becomes committed to a regulated model and supporting institutions grow around it, the financial and political costs of transitioning to a more flexible, market-oriented regime rise over time. These dynamics reflect increasing returns and self-reinforcing mechanisms that narrow the range of viable policy alternatives (Mahoney, 2000). Therefore, early choices regarding the regulatory model have long-term consequences, underscoring the importance of a careful and forward-looking design during the formative phase of the hydrogen market.

To conclude, the structural attributes of the emerging hydrogen market – including the expected low concentration of production, the decentralised nature of supply, the limited relevance of retail competition, lower liquidity barriers, the critical importance of dynamic investment signals, and the likely niche role of hydrogen in the medium term – strongly support the adoption of a pipeline-level, market-driven regulatory framework. A decentralised approach based on negotiated third-party access offers the greatest flexibility to align infrastructure development with evolving market needs while minimising risks associated with premature large-scale investment. Nevertheless, the regulatory framework must remain adaptable. Should market conditions shift substantially, regulatory structures can evolve to accommodate broader network coordination if necessary. Maintaining flexibility, avoiding early institutional lock-in, and carefully aligning regulatory intervention with market realities will be crucial to supporting the efficient and sustainable growth of the hydrogen economy.

6. Conclusions

This paper develops an economic framework for evaluating the appropriate market design of pipeline infrastructure, focusing on regulating natural gas and hydrogen transport networks. The analysis begins by identifying two key characteristics of pipeline infrastructure: natural monopoly features, which create a potential for market power, and the high asset specificity of investments, which necessitates mechanisms to guarantee cost recovery. Notably, the paper argues that the appropriate scope of regulation cannot be derived solely from the cost function of infrastructure but must also consider broader market structure considerations.

Two additional conditions are critical in shaping the need for regulation: market concentration at the commodity level and the impact of regulatory design on market liquidity. In sectors with significant upstream concentration, there is a heightened risk of market foreclosure, justifying stronger regulatory intervention. Moreover, regulating entire networks can enhance liquidity by standardising access conditions and facilitating trading.

This framework is applied to two case studies – the US and EU natural gas markets – illustrating different regulatory approaches shaped by distinct market structures. Drawing on these insights, the paper assesses the regulatory design proposed for hydrogen transport infrastructure in the European Union.

The analysis concludes that the case for directly replicating the EU gas market design for the hydrogen sector is weak under current market conditions. The structural attributes of the emerging hydrogen economy – low expected concentration of production, decentralised supply, limited relevance of retail competition, lower liquidity barriers, and the critical importance of preserving investment signals – favour a more decentralised, asset-level regulatory approach. A model based on negotiated third-party access, allowing for pipeline-level regulation and long-term contracting, would better support dynamic efficiency and infrastructure development aligned with current market needs. Inspired by the US experience, such a model would also maintain the flexibility to adapt regulatory structures over time as the hydrogen market evolves.

Accordingly, this paper recommends a review of the current EU regulatory framework for hydrogen transport infrastructure to enable the application of regulation at the level of individual pipelines rather than entire networks. Light-touch regulation based on negotiated TPA, supported by robust long-term contracting frameworks, could play a central role in enabling efficient investment and fostering competition. Ensuring secure and predictable infrastructure access rights will be essential to financing incremental capacity expansions.

While today's market characteristics point towards a pipeline-level, market-led regulatory model, the framework developed in this paper underscores the importance of maintaining regulatory flexibility. Should the hydrogen economy expand beyond current projections to become a widespread, cross-sectoral energy carrier, broader network-wide regulation could be reconsidered. Regulatory design should, therefore, remain responsive to market evolution, avoiding early institutional lock-in and preserving the ability to adapt to the dynamic development of the hydrogen economy.

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