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1 POLITICAL AND LEGAL CONTEXT

1.1 Context of initiative

The European Green Deal ('EGD') and the Climate law set the target for the EU to become climate neutral by 2050 in a manner that contributes to European competitiveness, growth and jobs. This, together with a 55% greenhouse gas emissions reduction target by 2030, requires an energy transition and significantly higher shares of renewable energy sources in an integrated energy system and acceptance and active participation of consumers in competitive markets, to benefit from affordable prices, good standards of service, and effective choice of offers mirroring technological developments.

On 14 July, the European Commission adopted[1] a first set of proposals to make the EU's climate, energy, transport and taxation policies fit for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels. The present initiative is equally part of the Fit-for-55 package[2]. It covers market design for gases. Whilst it will not deliver decarbonisation by itself, it will remove barriers for this to happen and create the conditions for this to take place in a more cost effective manner.

Electrification of demand sectors[3] will further increase as it is generally the most cost-effective and energy-efficient way to decarbonise final energy demand. Coupled with an increased contribution from renewables, energy efficiency and a circular economy, electrification delivers a substantial part of the emission reductions across the energy system.

Gaseous fuels (natural gas[4], biogas and biomethane[5], synthetic methane and hydrogen) will however continue playing an important role in the energy system. Their ability to store energy allows matching seasonal demand patterns and complements fluctuating supply of renewable electricity. For processes, which cannot easily be electrified for technical or economic reasons, gaseous fuels are likely to remain present in the EU's energy system. It is however clear, that these gases must be decarbonised on the way to 2050.

This document analyses how to adapt the current legal framework for the internal gas market (mainly the Gas Directive and the Gas Regulation) to facilitate the decarbonisation of gaseous fuels in a competitive manner at least economic costs whilst ensuring energy security and placing consumers at the heart of the energy markets. Two main pathways, are likely to emerge in parallel and expected to develop at different pace across the EU:

- A hydrogen-based infrastructure will progressively complement the network for methane gases;
- A methane-based infrastructure in which natural gas will progressively be replaced by other sources of methane (i.e. biomethane and synthetic methane, possibly occasionally blended with hydrogen).

Currently, some 300 Mtoe (350-400 bcm) of gaseous fuels are consumed in the EU per year, of which 95% is natural gas. They account for roughly 25% of total EU energy consumption, used for 20% of EU electricity production, and 39% of heat production. In line with the policy scenarios that underpin

[1] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

[2] https://eur-lex.europa.eu/resource.html?uri=cellar%3A91ce5c0f-12b6-11eb-9a54-01aa75ed71a1.0001.02/DOC_2&format=PDF

[3] Commission policy scenarios expect the share of electricity in final energy consumption to increase from currently 20% to about 32% in 2030 and 56% in 2050.

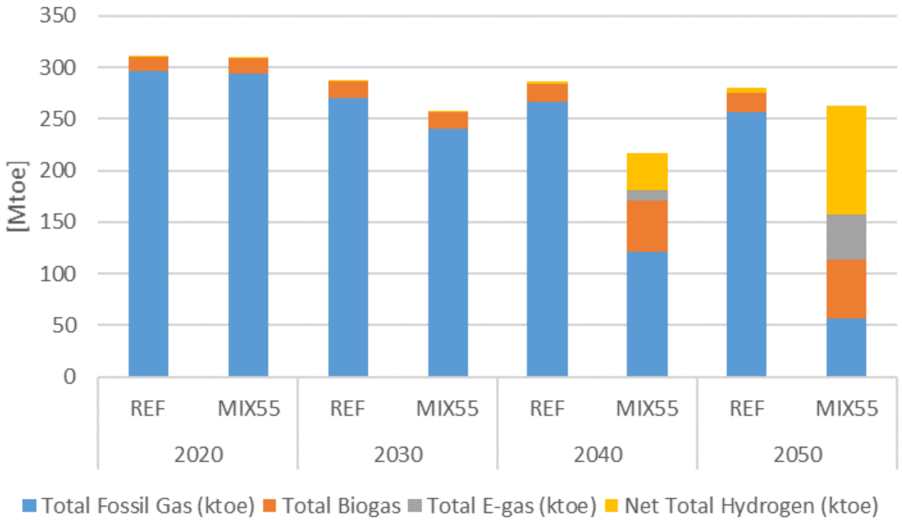
[4] In this document references to natural gas shall be understood as references to methane of fossil origin. Fossil gases include natural gas, hydrogen of fossil origin and synthetic methane produced from hydrogen of fossil origin.

[5] Biogas is a mixture of methane, CO2 and small quantities of other gases produced by anaerobic digestion; its precise composition depends on the type of feedstock and the production pathway. Biogas cannot be directly injected into the gas grid. Biomethane is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. Biomethane, subject to fulfilling specific gas quality standards, can be directly injected into the gas grid

the Fit for 55 initiative, biogas and biomethane, renewable and low-carbon hydrogen and synthetic fuels (E-gas) will gradually replace fossil gases and represent very significant shares of the gaseous fuels in the energy mix towards 2050. Conversely, the share of natural gas is projected to be significantly reduced and coupled with carbon capture usage and storage ('CCUS') technologies. Figure 1 shows the latest projections for consumption of gaseous fuels produced by the Commission with the PRIMES energy model. The projections also show that the energy carried by gaseous fuels would, after slightly decreasing between 2020 and 2030, stay in 2050 at about 85% of the current level.

Two scenarios are shown in the business as usual case (the Reference 2020 – REF) and in the Green Deal scenario (MIX).

Figure 1: Total consumption of gaseous fuels (Mtoe)[6]



Source: PRIMES

Under current framework conditions, biomethane, synthetic methane and hydrogen have significantly higher levelised costs of energy compared to natural gas[7]. This cost gap can be addressed by a much higher carbon price[8], by direct financial incentives in particular for renewable gases and by reducing the cost for access to the system for the gaseous fuels other than natural gas.

However, the renewable and low-carbon gases today face regulatory barriers for market and grid access that represent a comparative disadvantage versus natural gas. The differences in costs of production and potential of biomethane and hydrogen production between EU Member States are significant and are a strong argument for cross-border trade. Abolishing the regulatory barriers will enable renewable and low carbon sources of gases to compete in the EU gas market, bringing down costs of production, increasing cost efficiency and leading to less support measures and state aid. It will also enable supply of those gases to Member States, and end-consumers, that otherwise would not satisfy their demand[9].

1.2 Scope of initiative

The initiative aims to adapt the rules for the transmission, distribution, supply and storage of methane and hydrogen based gases. It lays down the rules relating to the organisation and functioning of these

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[6] Net total hydrogen consumption excludes hydrogen that is further processed to renewable fuels or liquids.
[7] Direct use of biogas for electricity/heat production may in several cases be less costly than converting it into biomethane.
[8] For instance, filling the gap between biomethane costs and natural gas prices by 2030 would require a carbon price of about 350 €/tCO2 (for a biomethane LCOE of 88 €/MWh).
[9] See in this regard also Annex 5

gas sectors, access to market and the operation of systems as well as rights of consumers of gases[10]. Where necessary, the rules for hydrogen and methane gases are differentiated to make them fit for purpose. Maintaining overall energy security is an underpinning factor.

1.3 Organisation and timing

The Commission has conducted a number of wide and targeted public consultations between 2019 and 2021[11] on the different problem areas covered by the present impact assessment. Given the cross-cutting nature of the planned impact assessment work, the Commission set up an inter-service steering group, which held regular meetings to discuss the policy options of the proposed initiatives and the preparation of the impact assessment. In parallel, the Commission has also conducted a number of studies for this impact assessment[12].

1.4 Links with other initiatives

The proposed initiative is focussing on enabling the markets to decarbonise gas consumption. It is strongly linked and complementary to the legislative proposals brought forward in the context of the Fit-for-55 package to implement the European Green Deal, including:

- The **revised Renewable Energy Directive** (‘RED II’), which is the main EU instrument dealing with the promotion of energy from renewable sources. It aims to incentivise the penetration of renewable energy, including renewable gases. Its proposed amendment[13] increases the target for renewable sources in the EU’s energy mix to 40% and promotes the uptake of renewable fuels, such as hydrogen in industry and transport, with additional targets. However, other low-carbon fuels (including low-carbon gases, such as low-carbon hydrogen) are not in the scope of RED and its revision. Such fuels can however also play a role in the transition, particularly in the short and medium term to rapidly reduce emissions of existing fuels, and support the uptake of renewable fuels such as renewable hydrogen. In order to fil in this gap and enable low-carbon fuels to be a viable solution for Member States in a transitional period, this Impact Assessment explores options for deploying a system of terminology and certification of non-renewable low-carbon fuels;
- The **Energy Efficiency Directive ('EED') and the related Energy Performance of Buildings Directive ('EPBD')** including the proposals for their amendment interact with the present initiative as they affect the level and structure of gas demand. Energy efficiency measures can alleviate energy poverty and reduce consumer vulnerability. As gaseous fuels are currently dominating in European heating and cooling supply and in the cogeneration plants, their efficient use stays at the core of the energy efficiency measures. The provisions previously contained in the energy efficiency legislation on demand response will be set out in the present initiative because these relate to incentivising flexibility in the market and participation of consumers in the market, both core subjects of the present initiative. The present initiative is coherent with the energy efficiency first principle: an open and competitive EU market with prices that reflect energy carriers’ production costs, carbon costs, and external costs and benefits would efficiently provide clean and safe hydrogen to end users who value it most.
- The **TEN-E Regulation**[14]**,** as proposed by the Commission in December 2020, aims to better support the modernisation of Europe's cross-border energy infrastructure for the EGD. It introduced hydrogen infrastructure as a new infrastructure category for European Network Development. The present initiative is complementary as it focuses on alignment of the national plans with the requirements of the European Network Development plan;

[10] See also Sector Integration Strategy
[11] For more information on the consultation and inter-service process, please refer to Annex 2.
[12] For the list of studies and a summary description, please refer to Annex 1.
[13] For an overview of the Commission’s proposals: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/delivering-european-green-deal_en#cleaning-our-energy-system
[14] COM(2020) 824 final

- As announced in the EU **strategy to reduce methane emissions,** the Commission will propose legislation to reduce methane emissions in the energy sector. The initiative will seek to improve information for all energy-related methane emissions. The present initiative seeks to facilitate the penetration of renewable and low-carbon gases, enabling a shift from natural gas;
- The **Emission Trading Scheme (´ETS´)** increases the price of using fossil fuels relative to renewable and low-carbon gases and, thus, fosters the demand of such gases and investments in related production technology. The Commission has proposed strengthening, including reinforcements in and extensions to the aviation sector, maritime and road transport, and buildings.

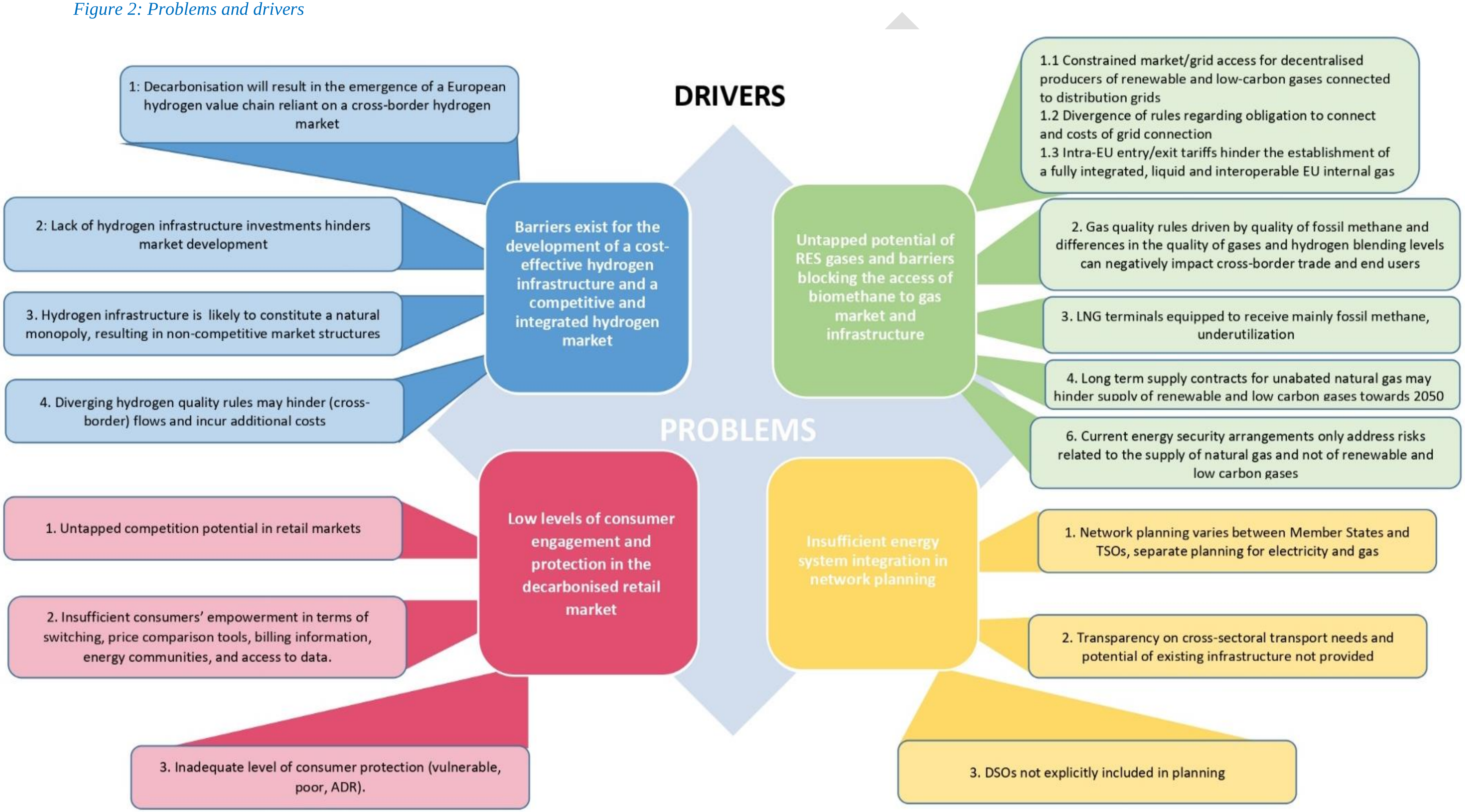
The present initiative is coherent and has clear synergies with these instruments and others (see also Annex 10).

1.5 Alignment with the FIT55 Impact Assessment

The quantitative assessments shown in this report build on the analysis performed for the Fit for 55 policy package. Consequently, all model-based analysis related to hydrogen and renewable and low carbon gases is aligned to the MIX H2 PRIMES scenario[15], which underpins the Impact Assessment supporting the proposal for a revised Renewable Energy Directive. The present assessment extends the analysis performed for the Fit for 55 initiative by exploring selected elements of the energy system in detail (e.g. options for different hydrogen pipeline deployment) while preserving the overall relationships between the energy supply and demand side. This ensures consistency with the underlying policies driving the transition to GHG neutrality as proposed in by the Fit for 55 initiative.

[15] The MIX-H2 scenario achieves the objectives of the EU hydrogen strategy. It is described in detail in the Impact Assessment accompanying the proposal for a revised Renewable Energy Directive.

Figure 2: Problems and drivers



2 PROBLEM DEFINITION

2.1 Problem area I: Hydrogen infrastructure[16] and hydrogen markets

Today, hydrogen represents a modest fraction of the European Union's energy mix. It is mainly used as industrial feedstock and is largely produced from fossil fuels[17] releasing CO2 emissions. Hydrogen is not yet a traded commodity and a hydrogen network is not yet an essential facility, as producers and consumers are not competing for access to a cross-border network for hydrogen transport[18]. Existing networks are privately owned and tailored for the point-to-point transport of hydrogen to industrial customers.

The Communication on a hydrogen strategy for a climate-neutral Europe[19] (the EU Hydrogen Strategy) published last year, as well as the hydrogen strategies of a number of Member States, define ambitions towards 2030 to prepare the offtake of renewable hydrogen (in particular hydrogen produced from water using renewable electricity through a process of electrolysis) (see Table 1). Next to renewable hydrogen, other forms of low-carbon hydrogen can play a role, primarily to rapidly reduce emissions from existing hydrogen production and to support the parallel and future uptake of renewable hydrogen.

Table 1: EU Hydrogen Strategy and national hydrogen strategies: envisaged developments towards 2030

	Today - 2024	2025 - 2030	2050
Electrolyser installed capacity	6 GW	40 GW	500 - 550 GW
Production RES H2	Up to 1 Mt	Up to 10 Mt	70 - 80 Mt
Infrastructure[20]	Infrastructure needs for transporting hydrogen over longer distance will remain limited.	Need for an EU-wide logistical infrastructure will emerge.	Fully developed EU hydrogen network in place (with connections to non-EU countries)
Electrolyser targets national hydrogen strategies (until June 2021)		27.5-28.5 GW	-

Source: EU Hydrogen strategy and national hydrogen strategies, PRIMES

The current regulatory framework for gaseous energy carriers does not address the deployment of hydrogen as an independent energy carrier via dedicated hydrogen networks or other infrastructure as an enabler of system integration. There are no rules on the operation of new hydrogen infrastructure or the repurposing of natural gas networks for the future transport of hydrogen. The security challenges of hydrogen deployment are also not addressed in the SoS Regulation[21] (see driver 5 under problem II).

The problem resides in the fact that barriers exist for the development of a cost-effective hydrogen infrastructure and integrated, competitive hydrogen market.

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[16] The term 'hydrogen infrastructure' refers to hydrogen pipelines, large-scale hydrogen storage and hydrogen import terminals.

[17] According to FCH JU (2019) Hydrogen Roadmap Europe today's share is 2%. This includes the use of hydrogen as feedstock.

[18] Merchant hydrogen (hydrogen that is not captive/dedicated to specific clients) represented less than 15% of total hydrogen production capacity in 2018. Energy Transition Expertise Centre (ENTEC,2021), the role of hydrogen import and storage to scale up the deployment of renewable hydrogen.

[19] https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1594897267722&uri=CELEX:52020DC0301.

[20] Whilst not really comparable as not based on the MIX H2 PRIMES scenario, Guidehouse (July 2021) foresees the emergence by 2030 of an initial 11,600 km hydrogen pipeline network, connecting emerging hydrogen valleys. This compares with approximately 1600 km today. The hydrogen infrastructure can subsequently grow to become a pan-European network, with a length of 39,700 km by 2040. Further network development can be expected after 2040. (https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/).

[21] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, OJ L 280, p.1.

2.1.1.1 Driver 1: Decarbonisation will result in the emergence of a European hydrogen value chain reliant on a cross-border hydrogen market

With renewable energy resources being key but unevenly distributed over Member States[22] the availability of well-integrated, cross-border hydrogen markets will be key to support the EU's climate neutrality objectives and ensure its cost-effectiveness.

Hydrogen networks will allow the transport of hydrogen from regions with excess capacity of renewable energy to supply demand centres in (cross border) regions with lower hydrogen production capacity. Any trade barriers for hydrogen and a lack of transport capacity or could hamper the development of the hydrogen value chain and decarbonisation.

In view of the variability of renewable hydrogen production but the need to provide stable supply to users, storage infrastructure will be important assets on such a hydrogen market. It allows hydrogen producers to optimise their economic activities by utilizing electrolysers on the basis of (favourable) price variations for renewable electricity instead of tailoring the operation of electrolysers to consumption patterns. Currently, salt caverns are the only proven large-scale hydrogen storage option but, due to geological conditions this storage option is only available in certain Member States[23]. Accordingly, large-scale storage will be scarce (especially at the ramp-up stages) thereby underlining the need for (cross-border) markets.

EU hydrogen demand might be partially covered by imports from third countries. Alongside pipelines, hydrogen can be imported from (distant) third countries by ships that can use a range of different modes to transport hydrogen such as in liquid form or as ammonia. As the optimal import means will also depend on the envisaged end use of hydrogen it is not yet fully clear what means of hydrogen import will become predominant[24]. Also the potential for hydrogen imports and exports in terms of volumes is less certain, at least by 2030. In any event, investments and operation would equally be dependent on functioning commodity markets (and on the available transportation infrastructure to reach demand centers)**.**

Low-carbon hydrogen ('LCH') and low carbon fuels ('LCFs') have decarbonisation potential. However, they are not defined and it can be expected, at least in the short term, that Member States will use LCFs/ LCH due to the low market penetration of RES Hydrogen. Therefore, not certifying LCFs in a comprehensive and harmonised manner risks to jeopardise the integrity of the EU market and hamper cross-border trade since it would create uncertainty about the real GHG footprint of such solutions.

An efficient hydrogen market can increase welfare by exploiting comparative advantages whilst the price signals it produces will steer investment decisions and the operation of hydrogen assets. Whilst the development of a hydrogen market has clear benefits, no such integrated hydrogen market exists today.

[22] JRC (2018), Wind potentials for EU and neighbouring countries; http://publications.jrc.ec.europa.eu/repository/bitstream/JRC109698/kjna29083enn_1.pdf.. Similarly, see also EHB June 2021 "Analysing future demand, supply, and transport of hydrogen" https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.

[23] Only 9 MSs have any significant salt cavern storage potential (Germany, the Netherlands, Denmark, Poland, Portugal, Spain, Romania, France, and Greece), complemented by several non-EU countries (UK, Norway, Bosnia & Herzegovina, Albania). Guidehouse assistance to the impact assessment for designing a regulatory framework hydrogen, p. 76.

[24] Hydrogen Council (2021) Hydrogen insights, a perspective on hydrogen investment, market development and cost competitiveness

2.1.1.2 Driver 2: Lack of hydrogen infrastructure investments hinders market development.

The development of a hydrogen market requires infrastructure.

Pipeline transportation is highly likely to be the most cost-effective means of transporting hydrogen for distances compatible with the European territory[25], compared to other means such as road-based or marine transport or transportation through the electricity grid of electricity before its transformation into hydrogen. A lack of hydrogen networks may increase the carbon footprint of production and render hydrogen more expensive for consumers, as they have divert to less cost-effective (and sustainable) transportation means[26]. As production and consumption of hydrogen ramp up across the EU, cross-border hydrogen networks will be required to meet transport needs from favorable production locations to demand centres. The construction of a pan-European grid would require considerable capital investments.[27] Existing natural gas networks can be partially repurposed for the transport of hydrogen, with significant cost savings compared to new-build infrastructure[28]. The same applies to large scale storage and, likely to lesser extent, import terminals.

However, there is no clarity on the context in which infrastructure investments can take place and barriers to exploit repurposing opportunities exist. There is no transparency on what parts of the gas grid may become available for repurposing, no clear rules exist on how repurposing could be organised, how (new or repurposed) hydrogen infrastructure is financed and whether current arrangements applicable to gas pipes (e.g. permitting and land use rights) continue to be applicable once these pipes are used for hydrogen transportation.

2.1.1.3 Driver 3: Hydrogen infrastructure is likely to constitute a natural monopoly, resulting in non-competitive market structures.

As hydrogen markets develop, dedicated hydrogen networks and possible other types of infrastructure are likely to constitute natural monopolies or essential facilities on which hydrogen producers and consumers depend in order to transport, store and receive hydrogen. While existing hydrogen pipeline infrastructure is currently unlikely to constitute a natural monopoly as current hydrogen producers and sellers/buyers are not competing for access to hydrogen infrastructure, it is expected to happen in the future, based on the following elements:

- pipelines have a sub-additive investment cost curve. This means that the total cost of transport services are expected to be lower for one pipeline operated by a single firm than for two pipelines with an equal transport capacity that are operated by two firms;
- other transportation means (such as transportation by trucks) would not provide suitable or competitive alternatives for most uses[29];

[25] JRC (2021), Assessment of Hydrogen Delivery Options, jrc124206_assessment_of_hydrogen_delivery_options.pdf Similarly, see also EHB June 2021 “Analysing future demand, supply, and transport of hydrogen” https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.

[26] See also Artelys, Trinomics, Frauenhofer, JRC Artelys, Trinomics, Frauenhofer, JRC , Trinomics, Frauenhofer, JRC modelling results and Annex 5

[27] Whist not comparable as not based on the MIX H2 PRIMES scenario, Guidehouse (April 2021) estimates total investment costs of the envisaged 2040 European Hydrogen Backbone to be in the range of €43 to €81 billion, covering the full capital cost of building new hydrogen pipelines and repurposing pipelines. Repurposed pipelines represent 69% of the total length. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

[28] The share of repurposed pipelines in a future hydrogen network is currently estimated to be about 69% overall with the share varying between Member States in accordance with e.g. the current availability of gas networks and network typology. The median estimate for the CAPEX of repurposed pipelines is on average 19% of newly build pipelines with minimum and maximum estimates varying from 10% to 28%. https://gasforclimate2050.eu/wp-content/uploads/2021/04/European-Hydrogen-Backbone_April-2021_V2.pdf

[29] See for instance: JRC 124206_assessment_of_hydrogen_delivery_options.pdf (europa.eu)

- refurbishing natural gas pipelines to hydrogen operations will be less expensive than new-build pipelines, and will hence offer a competitive advantage to the owners/operators of existing natural gas networks[30]. As a result, the hydrogen pipeline/ network “inherits” the natural monopoly character from the natural gas pipeline/network;
- hydrogen is expected to become a traded commodity with a high number of producers/sellers and buyers competing for access to transport infrastructure. This would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the EU hydrogen Strategy.

Natural monopolies could lead to the foreclosure of upstream (hydrogen production) and downstream (supply of hydrogen to end-users) activities within the hydrogen value chain, which may in turn lead to hydrogen consumers being deprived from supply or being confronted with higher prices in the end also affecting the ability for hydrogen to decarbonise the EU economy.

However, no rules exist to ensure market access and protect competition against the risk of market foreclosure and non-competitive market structures, while taking into account the specificities of a nascent market.

2.1.1.4 Driver 4: Diverging hydrogen quality rules may hinder cross-border flows and incur additional costs

Gas quality for pure hydrogen networks has so far received little attention as current hydrogen supply is predominantly organised on a point-to-point basis. Once hydrogen is injected from different production processes and transported through a meshed network, including across-borders, issues around hydrogen quality (i.e. purity) may arise.

Different applications require different hydrogen purity levels and can have different tolerances for the composition of the impurities. Industrial grade purity is required at a minimum 99,9%[31] (e.g. in ammonia and steel production and in refineries), fuel cell uses require a purity above 99,97%[32] (e.g. in road and rail transport), while used for its thermal value hydrogen purity is a less important parameter e.g. in power plant turbines.

Different sources and production methodologies lead to different hydrogen purity levels[33] and the transport via pipeline also has an effect on the purity: Existing gas pipelines converted for hydrogen transport can respect a 98% purity[34], which can represent a significant issue with reusing existing gas infrastructure for hydrogen transport. To ensure that the level of hydrogen purity matches end-use requirements, purification might be necessary as an additional step at added cost in the production process or at a later stage, e.g. at end-use points.

Currently, only a few national level standards are applicable or under development, while the European Committee for Standardization (CEN) is investigating the tolerance of infrastructure elements and end-use applications to hydrogen[35]. As of today, there is limited availability of data on and experience with hydrogen purity and its implication on the operation of infrastructure and appliances.

The lack of harmonised rules on a minimum purity level for hydrogen transportation can pose a risk to the unhindered flow and use of hydrogen in the near future. Such issues are expected to become

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[30] Trinomics (2020), Sector integration – Regulatory framework for hydrogen Final Report, p. 37 and following.
[31] Hydrogen Europe: common industrial grade is generally set at 99,95%.
[32] With a list of impurities with specific thresholds set out in existing standards: ISO-14687, SAE-2719 and CEN-17124
[33] E.g. for renewable hydrogen produced via electrolyses from renewable electricity for hydrogen produced from different qualities of fossil fuels, e.g. natural gas.
[34] Reference to Trinomics study: Sector integration – Regulatory framework for hydrogen.
[35] TC 234, TC 109.

particularly pertinent when dedicated hydrogen networks connect Member States and divergent technical rules, including quality specifications, constitute a barrier to the cross-border flow of hydrogen.

Thus a need exists to assure that diverging hydrogen quality (hydrogen purity and contaminants) rules hinder cross-border flows.

2.1.2 How will the problem evolve?

Today, the share of hydrogen represents a negligible share of all gaseous fuels, predominantly produced and used within chemical production sites and refineries[36]. In the MIX H2 scenario, the production of renewable hydrogen will increase to more than 17 Mtoe (or 6 Mt of hydrogen) in 2030 and can be 230 Mtoe (80 Mt) in 2050. The share of hydrogen in the total consumption of gases increases to 4% in 2030 and up to 40% in 2050 [37.]

If the above issues remain unresolved, market integration will be hampered, infrastructure roll-out slowed down and non-competitive markets outcomes can be expected. Higher hydrogen prices and lower uptake of hydrogen and lower decarbonisation will be the result. Member States may take national initiatives based on national strategies, but these efforts are likely to be dispersed, resulting in uncoordinated and weaker cross-border integration and network development. As geographical and geological circumstances vary among Member States, some will have no or limited access to hydrogen storage and import facilitates.

These problems will not only pose risks to the objectives as set out by the EU Hydrogen Strategy by 2030, but even more so beyond 2030 in view of the very high growth in hydrogen consumption and production envisaged beyond 2030 towards 2050.

2.2 Problem area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

Today, renewable and low-carbon gases represent a minor role in the EU energy mix. Biogas is primarily used on-site to generate heat and electricity. Biomethane totalled around 20 TWh in 2019, which, was less than 1% of the EU's natural gas consumption of about 3850 TWh. Blending hydrogen[38] into natural gas grids and the production and injection of synthetic methane only exist at the scale of demonstration or pilot projects.

The production costs of biomethane vary from 36 €/MWh to 116 €/MWh[39]. The differences in production costs show an opportunity for trade. However, unlike natural gas, which is normally injected at the transmission level, about half of the biomethane production capacity is connected to the distribution grid. Injecting biomethane into distribution grids may, on the one hand be realised at lower operational costs, but on the other hand it deprives the biomethane producers access to the wholesale market which is organised around the transmission grid and the market dominated by natural gas.

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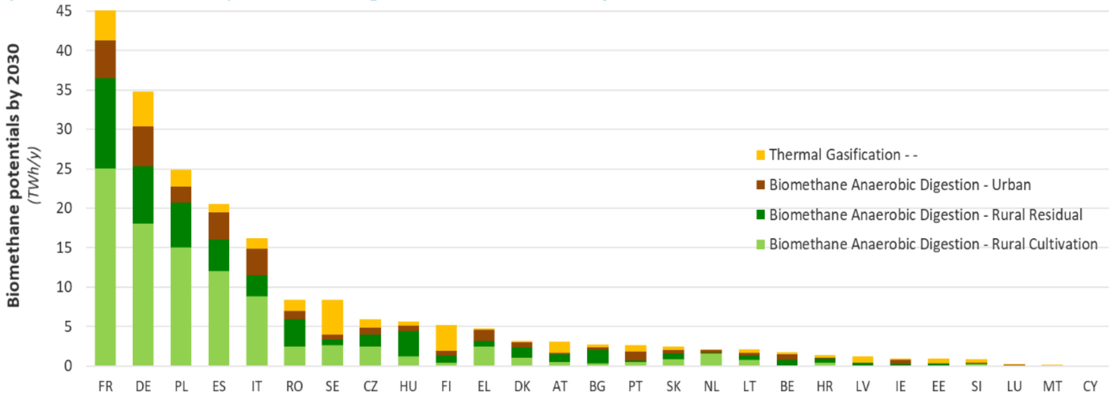
[36] Fuel Cells and Hydrogen Observatory (2020), https://fchobservatory.eu/observatory/technology-and-market/hydrogen-demand.

[37] See also table 1

[38] Blending means adding small quantities of hydrogen into the methane network. See for further details section 2.2.1.4

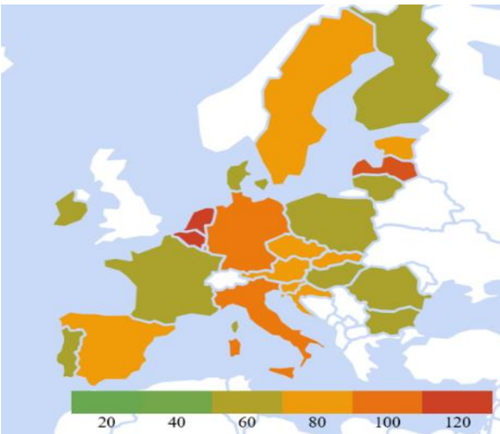
[39] Artelys, Trinomics, Frauenhofer, JRC (2021)

Figure 3: Estimation of biomethane potentials in 2030 – by MS[40]



Source: Fraunhofer

Figure 4: LCOE of biomethane in 2030 (€/MWh)[41]



This results in a problem that the potential to produce **biomethane remains untapped**. At the same time rules applicable to biomethane vary between Member States which **results in lack of level playing field between the producers of biomethane across the EU[42]**. Leaving biogas potentials from agricultural residues and waste (from sewage, municipal waste or landfills) unused represents a missed opportunity to make an additional step towards a circular economy as outlined under the CEAP[43]. Furthermore, the potential contribution of biomethane to the energy security is not considered in the current framework on energy security.

2.2.1.1 Driver 1.1: Constrained market and grid access for local producers of biomethane connected to the distribution grids

For efficient marketing of renewable and low carbon gases, **access to the gas wholesale market**, i.e. the virtual trading points (VTP), represents a key prerequisite. Yet, current market organisation and legislation in Member States does not necessarily foresee, in terms of market access, the integration of distribution systems in entry-exit zones[44] of TSOs and the participation of the distribution level injected gases in the wholesale market. Consequently, the tradability of locally produced gases at the VTPs is limited, blocking, in particular smaller facilities, from becoming active components of the energy system. Currently, entry-exit zones include, under various conditions, distribution grids injected gas in 10 countries (AT, BE, ES, DE, FR, CZ, PL, FI, IT, PT).

Biomethane plants connected to distribution grids may face another barrier in addition to the potentially restricted access to the VTP: physical injection at the distribution grid level may be capped

[40] Technical potential depend on time horizon as technology evolution can unlock additional potential.
[41] Source: Fraunhofer
[42] Similar situation may arise in the future as regards other renewable and low carbon gases when injected into the existing methane network
[43] COM(2020) 98 final, 11.3.2020;
[44] Please see for more details on entry/exit zones section 2.2.1.3

by the minimum demand levels in the local network as **gas flows are typically mono-directional** (from the transmission to the distribution level). Gas demand in distribution grids typically features a strong seasonal variation, notably where gas is used for space heating. Biomethane production on the other hand does not show a large seasonal variance[45]. Thus, the minimum demand typically occurring during summer represents the limiting factor for biomethane injection. Surplus gas injection may hence not be accommodated in the grid if no remedial action is undertaken. This may even lead to connection request denial. Besides connection to other distribution systems or local storage solutions (which may not always be available), reverse flow compressors from DSO to TSO level are the most effective infrastructure option. Only Austria, Spain and France appear to have such policies in place. In Italy, a pilot project is under way.

2.2.1.2 Driver 1.2: Divergence of rules regarding obligation to connect and costs of grid connection for renewable and low carbon gases

Biomethane plants may be connected to the transmission or the distribution grid, upon request to the TSO or DSO. Currently, a **connection obligation** exists in 16 Member States, while at least five countries do not have such a national obligation.

Table 2: Connection obligation for network operators across EU MS

Connection obligation exists	No connection obligation	No information available
AT, HR, CZ, DK, EE, FR, DE, HU, IE, IT, LV, LT, LU, NL, SI, ES	BE, PL, PT, SK, SE	BG, CY, FI, GR, MT, RO

Source: (ACER, 2020)

The allocation of **grid connection costs** between the network operator and the biomethane producer is handled quite heterogeneously across the EU:

- **Deep cost allocation** where producers pay all costs associated with the connection. This allocation is applied in Ireland, Italy and Spain;
- **Shallow cost allocation** where producers pay the cost for the physical grid connection and the system operator pays the necessary network reinforcement beyond the connection point. This allocation is applied in Austria, Belgium, Czechia, Denmark, Estonia, Finland and Sweden;
- **Super shallow cost allocation** where producers pay only partially or not at all for the physical grid connection, and system operators bear the majority of costs for the network reinforcement beyond the connection point and all/part of the physical connection. This allocation is applied in France, Germany and Lithuania.

When it comes to **grid injection tariffs**, in several Member States injection tariffs are lower for biomethane and hydrogen compared to tariffs for the injection of natural gas in transmission grids. This leads to a distorted level-playing field between biomethane and hydrogen producers in various Member States.

2.2.1.3 Driver 1.3: Intra-EU entry/exit tariffs hinder the establishment of a fully integrated, liquid and interoperable EU internal gas market

The current gas market model is organised around entry/exit zones in which TSOs transport two kinds of flows:

- **National flows** from an entry point (TSO, LNG terminal, storage, production) to an national exit point (DSOs, industrial consumers, gas-fired power plants);

[45] It is economically beneficial to maximise the utilisation of a biomethane plant (notably the fermenter) by opting for a minimal dimensioning of the plant.

- **Transit flows** from an entry point (TSO, LNG terminal, storage, domestic production) to one cross-border exit point.

The costs of transporting these flows are borne by the TSOs. They are recovered via grid tariffs taking into account the **allowed revenues** to remunerate their assets that are determined by the National Regulatory Authorities (NRAs). The methodology to define how allowed revenues are determined is not homogeneous among the Member States and it is not harmonised at EU level. Tariffs can be distinguished by three categories:

- The **exit tariffs at internal exit points**, which are paid only by the national consumers;
- The **exit tariffs at cross-border points**, which are paid by grid users other than national consumers;
- The **entry tariffs** paid by either national or non-national grid users (depending on where the flow crossing this point is destined).

The revenue repartition between these three kinds of tariffs is a complex matter[46].

The Network Code on tariff structures (NC TAR)[47] creates rules on which basis the allowed revenues can be collected, enhancing transparency of tariff setting, providing a framework based on cost-drivers and the principle of cost reflectivity. However, although being transparent and cost reflective, tariffs effectively render cross-border flows uneconomic in case the tariff of the needed capacity is higher than the price difference between markets, to the detriment of overall efficiency. The more borders are crossed, the higher the effect of adding tariff layer on tariff layer, which is called the 'pancaking' effect.

In the context of biomethane, pancaking may lead to a situation where the differences of production costs between Member States are not exploited. This may lower physical cross-border trade with renewable gases that might be compensated by higher natural gas imports.

2.2.1.4 Driver 2: Differences in gas quality and hydrogen blending levels can negatively impact cross-border flows and end- users, current gas quality rules not fit to deal with future developments

Today, gas quality is defined by CEN standards and at national level[48]. The EN 16726 standard on gas quality developed by CEN is not mandatory. Member States are setting the mandatory gas quality specifications, which can deviate from the CEN standard. In practice, the national specifications vary significantly between Member States[49] to take into account national specificities. Gas producers and suppliers are obliged to deliver the gas within quality ranges specified in commercial agreements between the network user and the system operator. In most Member States, system operators have either the obligation or the right to reject the injection of gases, which do not comply with the applicable gas quality specifications. In the cross-border context this means that TSOs at a cross-border point can reject gases of a quality not corresponding with the applicable (national) gas quality specification.

[46] Transit countries may have an interest in increasing their external entry and exit tariffs and decrease their internal exit tariffs to transfer the costs of transportation to other countries instead of their national consumers, but increasing too much these tariffs may result in shippers/traders choosing a different route. On the other hand, a country that would rely too much on internal exit tariffs may apply an unfair weight on its consumers, while the national services brought by the TSO also benefit other consumers.

[47] Commission Regulation (EU) 2017/460

[48] EN 16726 "Gas infrastructure – quality of gas – group H", published in OJEU in December 2015 provides a harmonised H-gas (natural gas) quality standard covering a number of relevant specifications.

[49] Study [Potentials of sector coupling for decarbonisation: Assessing regulatory barriers in linking the gas and electricity sectors in the EU | Energy (europa.eu).]

Beyond the quality standards, a cross-border coordination and dispute settlement framework for interconnection points (IPs) exists. The Interoperability and Data Exchange Network Code[50] obliges neighbouring TSOs to address gas quality aspects in their Interconnection Agreement for a given IP. Should the concerned TSOs fail to agree on a solution, the competent NRAs must adopt a coordinated decision. In the absence of such coordinated decisions, ACER can adopt an individual decision.

In practice, the injection of growing volumes of renewable and low-carbon gases, including biomethane and hydrogen, into the existing gas network is changing the parameters of gas consumed and transported in the EU, both at transmission and distribution levels. These changes in the quality of gases can have negative impacts on their cross-border flow and can cause problems and additional costs for system operators and end-users.

Biogas and biomethane have specific quality aspects to consider. In order to transport biogas in the existing gas network and use it in connected appliances it has to be upgraded to biomethane before injection.[51] Biomethane producing Member States developed their (differing) quality standards, and also CEN developed a biomethane quality standard for injection in the natural gas grid and for use in transport[52]. While biomethane can be used without the need for any changes in transport infrastructure and end-user equipment, quality related issues (e.g. due to differences in oxygen content) might still arise, including at cross-border IPs. Further, the lower and varying calorific value of the gas at high biomethane injection rates could lead to issues related to metering and billing to end-users, as flow meters could incorrectly measure the user's energy consumption.

Blending of hydrogen affects the operation of gas infrastructure, end-user applications, and interoperability of cross-border system. Hydrogen has a lower specific energy content which reduces the combustion properties of the gas mix, in particular the calorific value. This affects gas engines. Not all gas infrastructure components and gas consumers are able to cope with blended gases (see Figure 5).

Currently, allowed hydrogen blending rates are determined in some Member State and vary significantly. The interconnection agreements may not provide specifications regarding hydrogen concentrations. In addition, the future gas mix will lead to changes and more frequent fluctuations of the gas quality, making gas quality management in the existing gas network more complex and costly.

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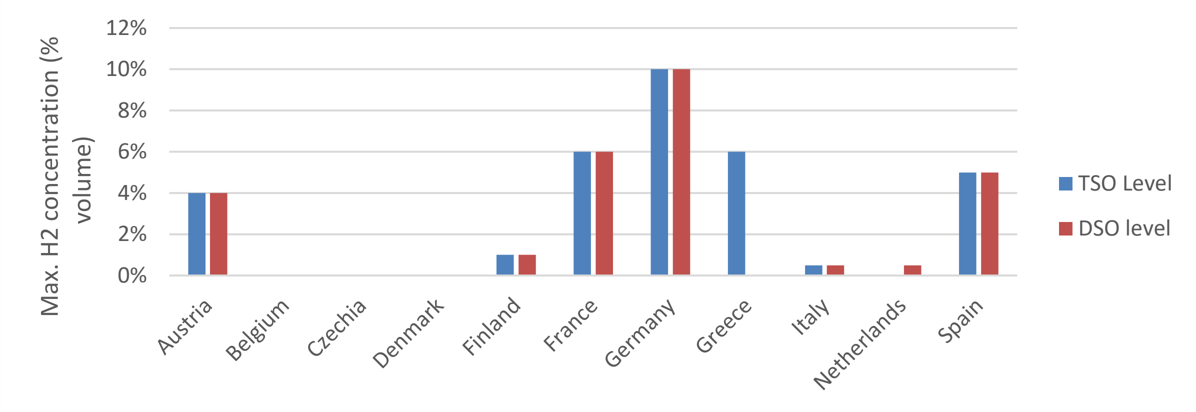
[50] Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules (Text with EEA relevance) EUR-Lex - 32015R0703 - EN - EUR-Lex (europa.eu).

[51]Biomethane can vary in characteristics such as Wobbe index; ENTSOG 2018.

[52] EN 16723-1: 2016 for the injection of biomethane in the natural gas grid and EN 16723-2: 2017 on natural gas and biomethane for use in transport.

Figure 5: Maximum hydrogen concentration regulation or objective



Source: (ACER, 2020), (FCHJU, 2021)

2.2.1.5 Driver 3: LNG terminals equipped to receive mainly natural gas, limited access for new gases to LNG terminals

The LNG market has significantly changed since the adoption of the Third Energy Package and rules applicable to LNG terminals in the EU. Efforts were made to utilize the LNG terminals to bigger extend, to move towards shorter-term capacity reservations and to enable small scale LNG and smaller players to develop. Some **barriers to access** LNG terminals persist, such as lack of transparency in tariff setting, capacity availability and allocation procedures.

Even if today's LNG facilities are primarily used for the import of natural gas from third countries, they could act in the future as facilitators for the import of renewable and low-carbon gases into EU. Biomethane, hydrogen and methanol can be liquefied and transported using LNG facilities provided some adaptations:

- In case the biomethane or synthetic methane meets the gas quality specifications, no changes are needed in LNG terminals;
- Regarding hydrogen, the physical and chemical differences between methane and hydrogen do not allow using existing LNG infrastructure as such and require its adaptation. Moreover, due to lower energy density of hydrogen the transport costs are likely to be higher;
- Hydrogen can be transformed to ammonia and methanol and LNG ships and terminals can be used to transport these energies. The associated costs for liquefaction, transport, storage and regasification stages are smaller.

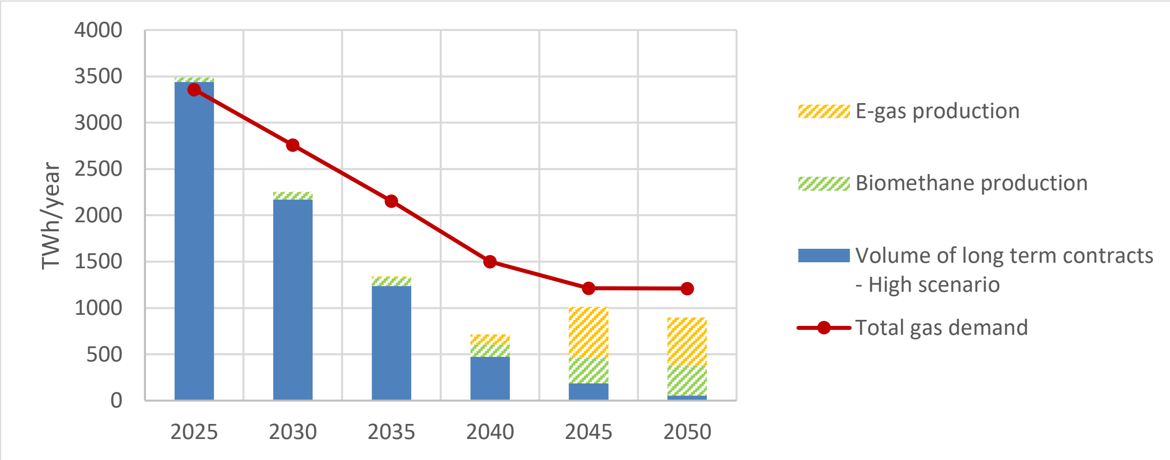
Addressing the residual barriers regarding access to LNG terminals could open the way to importing renewable and low carbon gases from abroad supporting the decarbonisation of the EU gas market.

2.2.1.6 Driver 4: Long term supply contracts for unabated natural gas may lock-in natural gas and hinder supply of renewable gases towards 2050

Long term contracts (LTC) for natural gas amount today to some 80% of the total supplies in the EU gas market. Some LTCs run as far as 2049.Long-term contracted volumes decrease over time (Cedigaz). While many of the current pipeline contracts date back to the 1990's, LNG contracts were in majority concluded after year 2000. As public information indicates, new LTCs could be signed, or the existing contracts could be prolonged, which may have a duration until 2050 and beyond. This will depend on the perception of market participants about EU achieving full net decarbonisation by 2050 and available technologies to reach this.

Natural gas supply contracts reduce the space left for biomethane and low-carbon synthetic methane. This may hinder the penetration of renewable and low-carbon gases as the market could be driven by imports of natural gas combined with contracts on the demand side, even in a situation where biomethane would be cost competitive (e.g., due to a significantly higher carbon price). Overall, the continued unconstrained existence of LTC's risks to lead to carbon lock-in. Consistency with the transition from today towards climate neutrality by 2050 could then only be ensured through large scale deployment of CCS technology.

Figure 6: Natural gas long term contracts overview



Source: Cedigaz database, calculations Artelys

2.2.1.7 Driver 5: Current energy security arrangements only address risks related to the supply of natural gas and not of renewable and low carbon gases.

The current framework on energy securityto prevent and manage possible disruptions are laid down in the SoS Regulation, which scope is limited to the risks related to the supply of natural gas only. Effects of repurposing or decommissioning of existing gas infrastructures are not explicitly addressed nor the positive impact or the specific risks of biomethane. Climate change induces risks impacting both infrastructure and production of renewable gas. Moreover the uses of smart grids, big data, artificial intelligence and automation enables a more efficient, resilient and lower-carbon operating model for the energy sector but increase the exposure to cyber threats. The current framework for ensuring energy security is not prepared for this change.

2.2.2 How will the problem evolve?

By 2030, a regulatory patchwork would still exist regarding access to wholesale markets, connection obligations and TSO-DSO coordination measures. Likewise, renewable and low-carbon gas producers will be facing different connection and injection costs across the EU, thereby resulting in an unequal playing field. Existing gas quality standards would remain non-binding and their application cross-border would not be aligned. Regarding biomethane, gas quality specifications would continue to be mainly defined by the quality parameters of natural gas. All these aspects are likely to lower cross-border trade of renewable gases that might be compensated by higher natural gas imports or higher support schemes. The utilisation of the terminals and imports could remain mainly for natural gas. With the increasing share of domestic production of gases and diversified suppliers, the current framework for ensuring energy security based on natural gas corridors, will become less effective. New cyber risks would become much more present, in a changing topology of the network.

2.3 Problem area III: Network planning

2.3.1 Problem: Insufficient energy system integration in network planning

As outlined in the European Commission's Energy System Integration Strategy, coordinated planning and operation of the entire EU energy system, across multiple energy carriers, infrastructures, and consumption sectors is a requisite to achieve the 2050 climate objectives. However, consideration of energy system integration in current network planning schemes and practices is deficient. Additionally, there are discrepancies between the EU-wide ten-year network development plan ('TYNDP') and national network development plans ('NDP') in relation to the requirement of e.g. joint scenario building between electricity and gas infrastructures or including a sustainability indicator for project assessment, which is all not required for NDPs. As a consequence, this may result in overestimating infrastructure needs in national plans, but also in the TYNDP as the TYNDP is based upon NDPs, and may hence negatively affect more efficient and coordinated infrastructure investments enabling a faster and better transition.

2.3.1.1 Driver 1: Network planning varies between Member States and TSOs, separate planning for electricity and gas

Member States are not required by EU law to develop a national network development plan, if the TSO is certified as ownership unbundled. Therefore, network plans do not exist in all Member States. The TYNDP covers in principle only cross-border infrastructure and is of lower granularity.

Additionally, in about 74% of Member States there is either a methane NDP or no NDP at all, while only in two cases a cross-sectoral approach is taken.[53] Planning on national level is hence based on sectoral needs, and, in contrast to the requirement of joint scenario building between gas and electricity at EU level, can be even based on different scenarios used for different energy vectors. Uncoordinated planning risks that synergies between different sectors are not exploited leading to inefficient investments.

2.3.1.2 Driver 2: No transparency on potential of existing infrastructure for repurposing or decommissioning.

While it is expected that demand for natural gas will decrease significantly, infrastructure of one sector, e.g. gas, may provide services for transporting energy to the benefit of another sector (e.g. electricity) and hence reduce overall infrastructure investments. Current development plans focus on the identification of additional investments, while neglecting information on which infrastructure may not be required anymore in the future. Additionally, without providing this information, the impact on energy security of Member States downstream of the Member State where infrastructure is planned to be used for another purpose or would be decommissioned could be negatively affected.

2.3.1.3 Driver 3: DSOs not explicitly included in TSO planning

Current planning practices and obligations on gas TSOs and DSOs to cooperate on network planning vary significantly across Member States leading to suboptimal information provision for planning purposes. Some Member States have obligations for the TSO(s) and DSO(s) to cooperate e.g. in order to define the most appropriate level for connection of new biomethane plants[54].

ACER and CEER (Council of European Energy Regulators) note that while TSOs generally provide or publish information on the network and DSOs on connections, the level of information sharing varies per country and usually there is no obligation for the TSO to take the information from DSOs into consideration. In some countries combined transmission and distribution system operators exist,

[53] ACER OPINION No 09/2020, Annex I

[54] This includes France, where the French NRA deliberation N° 2019-242 defines the procedures for assuring the 'right to connect' established by law 2018-938. The deliberation 242 requires French gas TSOs and DSOs to cooperate in order to establish a zoning program for the connection of biomethane projects. Candidate biomethane producers must register in a capacity management register, which triggers the development of detailed (for the distribution level) or feasibility (for the transmission level) studies. Based on the estimated costs and the cost allocation rules defined in deliberation 242, the preliminary connection agreement can be signed (with the producer eventually paying for part of the connection and reinforcement costs).

such as in Denmark (Energinet) and Luxembourg (Creos)[55]. However, most EU Member States have separate operators for gas transmission and distribution networks.

2.3.2 How will the problem evolve?

Electricity and gas are already interlinked mainly by gas to power assets. However, with power to gas assets, such as electrolysers, the interlinkages between electricity and gases including hydrogen is expected to become more integrated. The TEN-E proposal already includes the requirement of joint scenario building as well as hydrogen as new infrastructure category. Although hydrogen infrastructure is part of the TYNDP, the TEN-E proposal does not require the inclusion in the national plans. Without reflecting a higher degree of integration and coordination, the problem of different approaches to network planning and little information on planned decommissioning or repurposing entails the risk of leading to more inefficiencies, both in terms of sector integration, but also for the integration of renewables gases in the methane-based infrastructure.

2.4 Problem area IV: Low level of customer engagement and protection in the green gas retail market

2.4.1 Problem: Insufficient customer protection, lack of participation and rigid competition make the green methane gases difficult to access the retail market

For new gases[56] to play a full role in the energy transition, the retail market rules should empower customers to make low carbon choices. This is not currently the case. Retail gas markets exhibit market concentration and low levels of new entry and innovation. This prevents customers[57] from benefiting from competition by making low carbon choices.

2.4.1.1 Driver 1: Untapped competition potential in retail markets

Limited competition in many Member States explains poor customer satisfaction and engagement in the gas market, as well as slow uptake of new gases. In spite of falling prices in wholesale markets, gas prices for household customers rose between 2010 and 2019.[58] Industrial customers pay, in general, two to three times less for their gas than household consumers.[59]

Non-targeted **price regulation** still exists in 15 out of 27 gas household markets[60] and in the non-household market in France, Portugal, Denmark, Slovakia, Hungary and Bulgaria.[61] Price regulation – particularly with low or negative mark-ups - hinders entry by suppliers of new products, notably green gases, and can result in consumer disengagement. Low mark-ups may even lead to market foreclosure in Hungary, Lithuania, Romania, Bulgaria, Slovakia and Cyprus.[62]

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[55] Luxembourg is exempted based on Art. 49 (6) of Directive 2009/73/EC from applying Art. 9 (ownership unbundling) of the same Directive.
[56] This section concerns gases which are injected in the network covered by problem area II.
[57] This section uses the term customer to denote both household and/or non-household customer that purchases electricity. The term 'consumer', as defined in Article 2 (a) of Unfair Commercial Practices Directive, is used interchangeably with 'household customer'.
[58] See figure 18 in annex 9 on Household prices in 2019.
[59] Energy Prices and Costs SWD, 2020, p. 66.
[60] ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 47. An up-date on the number of Member States with regulated price may be available when the next ACER report will be published (foreseen in September 2021). Note that in context of **supplier of last resort schemes**, all but seven out of 23 screened member states intervene in the price setting in some fashion. See ACER Market Monitoring Report 2018 – Consumer Empowerment Volume, p. 12.
[61] Retail market barrier study, final report, p. 50; ACER market monitoring report 2019, Energy Retail and Consumer Protection Volume, p. 50.
[62] Retail market barrier study, final report, p. 50. See also figure 19 in annex 9 on Average annual mark-up in retail gas markets for household consumers.

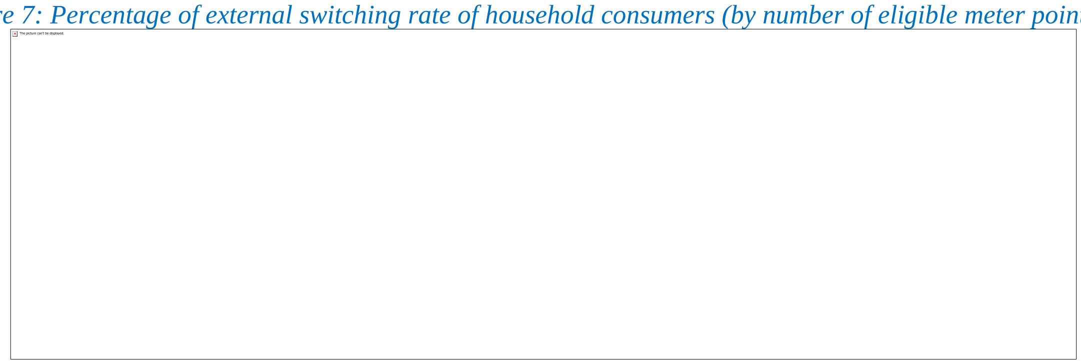
Household gas markets continue to be more concentrated than industrial and commercial markets[63] indicating high entry barriers for new suppliers particularly of renewable and low carbon gases.[64] While consumer choice has widened in recent years, a closer inspection reveals that variety of offers in Member States are mainly fixed offers. The offer and uptake of other, more innovative products, remains limited.[65] In 2019, **"green" gas offers were available in only seven out of 25 screened Member States**.[66] However, countries with a more liberalised retail market tend to have a higher percentage of "green" offers.[67]

2.4.1.2 Driver 2: Insufficient customer empowerment in terms of switching, price comparison tools, billing information, energy communities, and access to data.

To be able to make sustainable energy choices, customers need sufficient **information on their energy consumption and origin**, as well **efficient tools to participat**e in the market. Today customers are not sufficiently engaged in the gas market, which still lags behind on consumer protection compared to the electricity sector, especially with regards to **bills and billing information**, **switching** and **price comparison tools.** Consumers face particular issues in understanding the basic information in their energy bill.[68] There is a high divergence in particular in the internal market regarding information on sources of energy and historical consumption.[69]

Switching is an important indicator. Without this pressure, there is no incentive for suppliers to compete for customers, notably by offering renewable or low carbon options. Switching rates **in some countries are still below 1%**, which may be attributed to consumer inertia and aggravated by further price increases due to decarbonisation.[70,71] Consumers often encounter difficulties to understand the terms and conditions of their **energy contracts**, especially with regard to termination,[72] **as exit and termination fees** discourage consumers switching.[73]

Figure 7: Percentage of external switching rate of household consumers (by number of eligible meter points)



Source: (CEER, 2018)[74]

[63] See 2019 ACER Market Monitoring Report – Energy Retail and Consumer Protection Volume, pp. 20-23. See also Annex 9 for more information.
[64] ACER Market Monitoring Report 2019 – Energy Retail and Consumer Protection Volume, p. 42.
[65] ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 55.
[66] ACER market monitoring report 2019, Energy Retail and Consumer Protection Volume, p. 55.
[67] ACER Market Monitoring Report 2015, Electricity and Gas Retail Markets, p. 18.
[68] *Investigating the benefits of aligning EU consumer protection and information rules in the gas and electricity sectors*, VVA study p. 51-52
[69] See Evaluation section 7.1.2.
[70] European Barriers in Retail Energy Markets Project: Final Report; European Commission, 2021, p.59.
[71] Consumer study on precontractual information and billing in the energy market, final report, p. 91 https://ec.europa.eu/info/sites/default/files/final_report_2_july_2018.pdf.
[72] BEUC, 2017, Stalling the switch, 5 barriers when consumers change energy suppliers
[73] See Evaluation section 7.1.2.
[74] CEER Monitoring Report on the Performance of European Retail Markets 2018, p.31..

Price comparison tools (PCTs) facilitating consumer engagement are inconsistently developed among Member States and customers.[75] Even where available, comparison may only be possible based on price rather than renewable credentials. Malpractices (e.g. default offers, misleading language) prevent consumers from access to clear, independent, and free of charge information about their gas supply.

In several Member States, the creation of **energy communities[76]** has been a solution to enhance public acceptance of renewable gas installations.[77] However, energy communities still struggle to operate on the green gas market,[78] despite their potential to contribute to the uptake of renewable energy.[79] This may be attributed to a series of institutional barriers.[80,81] The enabling framework for 'renewable energy communities' (REC) in the Renewable Energy Directive 2018/2001/EU does not facilitate consumers distant from production sites (e.g. in cities) buying renewable and low-carbon gases and do not fully tap community potential for bringing more volume or less costly[82] renewable and low-carbon gas to the system.[83,84]

Limited access to smart metering and **to data** can also contribute to low engagement by consumers. Smart metering help customers manage energy consumption and supports energy efficiency. It also improves billing accuracy - one of the largest sources of consumer complaints[85]. Currently, the business case for gas smart metering[86] remains more challenging than that for electricity, and as a result, its deployment is limited and is progressing at a slow pace across the EU[87]. Existing legislation

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[75] Consumer study on precontractual information and billing in the energy market, final report, p. 91 https://ec.europa.eu/info/sites/default/files/final_report_2_july_2018.pdf. See Evaluation, section 7.1.2.

[76] As defined in glossary.

[77] Public resistance is derived from increased vehicle traffic in the area (linked to biogas or biomethane transport), odour associated with biogas production, concerns over impact of biogas production on local air quality and pollution, as well as safety concerns around local biogas and biomethane production. See Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 5; T. Bauwens and P. Devine-Wright, 'Positive energies? An empirical study of community energy participation and attitudes to renewable energy' (2018) Energy policy 118; https://www.biogaschannel.com/en/video/biomethane/7/acceptance-biogas-how-biomethane/1378/; and GRDF, 'Méthanisation Agricole Retour d'expérience sur l'appropriation locale des sites en injection', 2016.

[78] The increase in energy communities in 2019 was primarily in the electricity sector. Out of the 642 members of REScoop in 2021, only an estimated 3% are active in the gas sector. See Frontier study, 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 10.

[79] By 2050, 45% of renewable energy production could come from citizens and 37% of that production could come through from collective projects, such as energy communities. See Joint Research Centre (2020), 'Energy communities: an overview of energy and social innovation.

[80] Benjamin Huybrechts and Sybille Mertens, 'The relevance of the cooperative model in the field of renewable energy [2014] Annals of Public and Cooperative Economics, pp. 199-201; Binod Prasad Koirala, 'integrated community energy systems' (DPhilthesis, Delf University of Technology 2017, p.1; Stakeholder interview with Cormac Walsh from Energy Cooperatives Ireland, 12th of June 2021; Frontier et al's report (2019), 'Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU - Final report', p. 49.

[81] One of the drivers for the heterogeneous picture of energy communities across Member States have been the varying national legislative frameworks in place for energy communities. See Frontiers, 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', pp. 8-9; Ronne, A., and F.G. Nielsen, 'Consumer (Co-)Ownership in Denmark', Energy Transition - Financing Consumer Co-Ownership in Renewables, Palgrave Macmillan, Cham, 2019.

82 Due to the value over profit mentality of energy communities, lower profitability is needed for projects. Financing the projects with citizen results in lower rate of return requirements and lower overall costs. See Artelys study (2021).

[83] Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 11.

[84] For more information on energy communities see Annex 9.

[85] The 9th ACER/CEER Market Monitoring Report – Energy Retail and Consumer Protection Volume (2020), shows (in its figure 55) that the biggest average share of complaints regarding gas suppliers concerns invoicing/billing and debt collection (40%).

[86] For more information on smart metering see Annex 9.

[87] See also Evaluation Report, section 7.1.2.

lacks rules[88] on data management to govern processes by which data is sourced, validated, stored, protected and processed and by which data can be accessed by suppliers or customers[89]. This is market entry barrier for new entrants. The necessity to adapt to **different data management models** for each national market has an impact on the resources of potential market newcomers. The fact that not all countries have rolled out smart meters yet also creates **significant differences in the availability and accessibility of data**.

2.4.1.3 Driver 3: Inadequate consumer protection in particular for vulnerable and energy poor

The EU's increased climate ambition will result in low income households across the EU bearing a relatively higher burden in terms of heating fuel expenses compared to wealthier households[90][91]. In 2019, natural gas accounted for 32% of the EU final energy consumption in households, the highest energy source[92]. 64% of energy use by households was for home heating where demand is prices inelastic. Gas decarbonisation is likely to result in further price increases.

There is currently a mismatch of energy poverty and vulnerable customers coverage across internal energy market legislation. This results in a lack of coherence with other EU interventions in the wider energy and climate domain.

Protection of gas consumers also relies on the availability of effective means of dispute settlement. All Member States, except Cyprus, have implemented an ADR mechanism for both electricity and gas, in most cases free of charge for final household customers. However, there are still varying levels of available mechanisms and information on how to access such mechanisms –for example legal maximum processing times vary substantially across MSs and can reach up to six months[93].

2.4.2 How will the problem evolve?

The identified gaps in all customer empowerment and protection areas, including switching fees, market-based prices, basic contractual rights, vulnerable consumers, and energy communities are likely to worsen if not properly addressed. Both the legal framework and energy policies should, thus, be improved where needed to constantly protect and empower customers, namely households. This should be pursued still in a flexible way to adapt to the changing energy landscape and technologies, while respecting national features, where suitable.

3 WHY SHOULD THE EU ACT?

3.1 Legal basis

The planned measures of the present initiative seek to advance the four objectives set out in Article 194 TFEU, while at the same time contributing to the decarbonisation of the EU's economy. The planned measures are to be adopted on the basis of Article 194 (2) TFEU together with Article 114 (1) TFEU. In the field of energy, the EU has a shared competence pursuant to Article 4 (2) (i) TFEU.

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[88] Current provisions regarding smart metering: Articles 3(8) and Annex I.2 of the Gas Directive 2009/73/EC; also complementing provisions can be found in Articles 9(2); 10(2); 12(2b) of the Energy Efficiency Directive (EED) 2012/27/EU; provisions regarding access to data: Article 41(1)(q), Article 45(first paragraph), and Annex I (1h) of the Gas Directive 2009/73/EC.

[89] Adapted from: CEER Report "Benchmarking report on removing barriers to entry for energy suppliers in EU retail energy markets" (2016) p. 19; See also VaasaETT, "Market Entrant Processes, Hurdles and Ideas for Change in the Nordic Energy Market", p.22, (2014).

[90] The introduction of a carbon price would increase end-consumer prices for fossil fuels (household heating and cooling expenditure and gasoline for vehicles) to a different degree depending on the carbon price levels and on the underlying relative level of existing other taxes on fossil fuels. [to be removed if ETS extension is not proposed]

[91] Draft ETS IA

[92] Electricity for 25%, renewables for 20% and petroleum products for 12%. Eurostat

[93] ACER Market Monitoring Report 2018 –Consumer Empowerment Volume.

3.2 Subsidiarity: Necessity of EU action

To achieve EU decarbonisation goals it will be necessary to gradually replace natural gas by decarbonised energy carriers including electricity, renewable heat and decarbonised gases. The speed and scope of this transition, including how much of which gaseous fuels will be part of the energy mix, will depend on the chosen decarbonisation pathway and the deployment of other policy instruments. However, the current regulatory framework for gas focuses on natural gas and does not anticipate the emergence of alternative methane gases, such as bio-methane, or other gaseous fuels, such as hydrogen.

Currently, there are no rules at EU-level regulating dedicated hydrogen networks or markets and LCH and LCFs. In view of the current efforts at EU and national level to promote use of renewable hydrogen as a replacement for fossil fuels, Member States would be incentivised to adopt rules on the transport of hydrogen dedicated infrastructure at national level. This creates the risk of a fragmented regulatory landscape across the EU, which could hamper the integration of national hydrogen networks and markets, thereby preventing or deterring cross-border trade in hydrogen. Harmonising rules for hydrogen infrastructure at a later stage (i.e. after national legislation is in place) would lead to increased administrative burden for Member States and higher regulatory costs and uncertainty for companies, especially where long-term investments in hydrogen production and transport infrastructure are concerned.

When it comes to biomethane, without an initiative at EU level, it is likely that by 2030 a regulatory patchwork would still exist regarding access to wholesale markets, connection obligations and TSO-DSO coordination measures. Likewise, without some harmonisation at the EU level, renewable and low-carbon gas producers will be facing vastly different connection and injection costs across the EU, resulting in an unequal playing field.

Without further legislation at the EU level Member States would continue to define gas quality specifications based on the quality parameters of natural gas. Therefore, biomethane producers would also in the future need to adapt to this quality at additional cost. The rules on hydrogen blending would be left to the Member States without the definition of allowed hydrogen blending levels at cross-border interconnection points.

All these aspects are likely to lower cross-border trade with renewable gases that might be compensated by higher natural gas imports. The utilisation of the LNG terminals and imports could remain restricted to natural gas, despite that no adaptation of LNG terminals would be necessary in case competitive biomethane or synthetic methane from non-EU sources were available.

Without adjusting the national planning provisions, there is a risk that NDPs and the TYNDP (which builds on NDPs) become inconsistent. Member States may decide to adapt their national plans, but without EU's action it cannot be ensured that all NDPs follow the same basic framework. Ensuring consistency between EU and national network development planning is of Union relevance as it cannot be achieved in an efficient way only on the basis of the European plan due to a lack of more detailed information on network level. Close interaction and informed decisions based on local circumstances are required. It is therefore necessary that the methodology and overall framework for the European planning process and the national planning is consistent with each other.

Moreover, an EU-wide framework for introducing competition on methane retail markets and enabling consumers' choice is beneficial for providing level playing field for energy producers and suppliers as well as to benefit the consumers. Harmonised approach to metering and billing as well as consumer protection provisions safeguard the level playing field for suppliers and provide equal rights for energy consumers. It also facilitates providing cross-border services.

The current framework for ensuring gas supply security will not be adequate for the needs and threats of the future decarbonised gas system. Uncoordinated national emergency preparedness for the new gases risks undermining their effectiveness in case of disruptions. The EUCJ ruling of 15 July 2021 (Case C-848/19) confirmed the need to consider security of supply and energy solidarity in Commission's initiatives.

3.3 Subsidiarity: Added value of EU action

The initiative aims at modifying existing EU legislation and creating a new framework for an internal hydrogen market, which is key to achieve a cost efficient clean hydrogen economy.

The challenges cannot be addressed as efficiently by individual Member States as fostering more efficient and integrated EU markets for gases requires harmonised and coordinated approaches by all Member States; which can only be achieved by EU action. The initiative is also aimed at avoiding the distortive effects of uncoordinated, fragmented policy initiatives as many Member States develop national approaches e.g. with regard to hydrogen deployment. EU action has significant added-value by ensuring a coherent approach across all Member States and towards third countries, as achieving the decarbonisation objectives of the EU may require imports of renewable and low carbon gases from third countries.

The initiative on decarbonised gases also contributes to achieving binding EU-level objectives. The EU has already committed to achieving a share of at least 32 % of renewable energy sources in total energy consumption by 2030 and has issued an ambitious strategy for the deployment of hydrogen to reach 40GW of installed electrolyser capacity by 2030. The European Commission has recently proposed to cut net greenhouse gas emissions even further by at least 55% compared to 1990 levels by 2030, up from the current target for 2030 of at least 40%. The greenhouse gas emissions reduction target of 55% is assessed to lead to a share of renewables of between 38% and 40 %. Gaseous fuels will continue to provide an important share of the energy mix also by 2050, requiring the decarbonisation of the gas sector via a forward-looking design for competitive decarbonised gas markets.

Consequently, the objectives of this initiative cannot be achieved only by Member States themselves and this is where action at EU-level provides an added value.

As regards hydrogen, the creation of regulatory framework at EU-level for dedicated hydrogen networks and markets would foster the integration and interconnection of national hydrogen markets and networks. EU-level rules on the planning, financing and operation of such dedicated hydrogen networks would create long-term predictability for potential investors in this type of long-term infrastructure, in particular for cross-border interconnections (which might otherwise be subject to different and potentially divergent national laws).

EU coordinated emergency preparedness for the current gas sector has proven to be more efficient than action only at national level.

4 OBJECTIVES; WHAT IS TO BE ACHIEVED?

4.1 General objectives

Table 3: General policy objective

General policy objective
Contribute to the EU's decarbonisation in a cost-effective manner by facilitating the creation of a European hydrogen market and the gradual decarbonisation of gaseous fuels markets

4.2 Specific objectives

Table 4: Specific objectives

Objective	Sub-objectives
Facilitate the	- Enable the emergence of an efficient, integrated EU hydrogen market

emergence of an open and competitive EU hydrogen value market	- Remove barriers and ensure incentives to invest in hydrogen infrastructure - Address risk that the natural monopoly character of hydrogen infrastructure gives rise to non-competitive market structures. - Ensure cross –border integration, unhindered hydrogen (cross-border) flows and required quality for end-users
Ensure access of renewable and low carbon gases to the existing methane networks and markets and their security of supply	- Facilitating access of local production of biomethane to the gas markets across EU - Facilitating connection rules and injection - Ensuring access to LNG terminals for RES&LC gases - Ensure unhindered cross-border flows for RES&LC gases - Tackle risk of negative impact on end-users in terms of gas quality - Avoid lock-in into LTCs for natural unabated gas - Improve the resilience to relevant threats of the future gas system integrating renewable and low carbon gases.
Ensure transparent and inclusive infrastructure planning	- Provide transparency for repurposing existing gas networks - Enable cost efficient planning on the basis of scenarios that are in line with the climate target objectives
Give consumers tools to choose the cheapest decarbonisation options	- Increase competition in retail renewable and low carbon gas markets by also addressing price regulation - Strengthening consumer engagement in such market. - Ensure an adequate level of consumer protection

5 AVAILABLE POLICY OPTIONS

5.1 Options in the problem area I: Hydrogen infrastructure and markets

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5.1.1 Baseline for problem area I: hydrogen infrastructure and markets.

The baseline represents the early and unregulated stage of the nascent EU hydrogen market. Today, about 1600 km of hydrogen transportation infrastructure exists. It is fragmented with few cross-border connections. The conditions under which these networks have been built, sized and are used are negotiated between hydrogen producers and, mostly, industrial consumers. Other infrastructure, such as large scale storage and import terminals for liquefied hydrogen do currently not exist within the EU.

In the base line, the assumption is that adopted and planned policy initiatives under the Fit for 55 package will contribute to the development of renewable hydrogen demand and, consequently, its production but will not include a common EU terminology and certification system for LCFs/ LCH. The projection of these and other variables are used in the base-line scenario for this impact assessment, called here the MIX H2 scenario[94] that is coherent with the fit for 55 policy package.

This development will progressively increase the need for transportation means as locations for cost-effective and high volume renewable hydrogen production are unlikely to be located next to existing demand centres. The same will happen for storage infrastructure and, possibly, import infrastructure. The proposed funding of hydrogen infrastructure as well as its integration in infrastructure planning under the TEN-E regulation will promote (cross-border) hydrogen infrastructure development.

[94] These projections have been obtained using the PRIMES energy system model and are documented in detail in the Impact Assessment accompanying the proposal for a revised Renewable Energy Directive

However, in the base-line there are no additional rules to accommodate this need for infrastructure or rules for its operation.

Whilst Member States will likely take initiatives based on national strategies and approaches, these efforts will be dispersed, resulting in uncoordinated and weak cross-border integration and transportation infrastructure development. As geological and geographical circumstances vary among Member States, some will have no or limited access to large-scale hydrogen storage and import facilitates.

5.1.2 Description of policy options

In order to address the problem and its drivers as set out in Chapter 2 and in view of the objectives as defined above in Chapter 4, different packages of policy options are considered. Each of these packages reflect different sets of more detailed measures that seek to address the problem and its underlying drivers. The detailed measures considered to be part (or not) of a given policy option are summarised in Annex 6. In the same annex, more detailed descriptions of each of these main regulatory principles and their specific advantages and disadvantages are provided. Please note that certain hydrogen related issues are also dealt with under Problem Area 2 and 3, in particular on cross-cutting issues as SoS and network planning.

5.1.2.1 Option 0: Business as Usual ('BAU')/Non regulatory approach

In BAU, there are no rules or restrictions at EU level on the ownership or operation of infrastructure, or its financing. Infrastructure is operated by unregulated companies that can combine hydrogen production and supply activities with the operation of hydrogen infrastructure without rules on potential market foreclosure. They can set conditions (if any) for the operation of and access to infrastructure freely and guided solely by the business interests as perceived by the companies concerned. LCH and LCFs are not defined or certified.

Hydrogen infrastructure and its operation is currently not subject to any EU energy market regulation and stronger enforcement of existing rules is thus not a viable option. During the earlier stages of natural gas market liberalisation, ACER, in collaboration with NRAs and stakeholders developed a 'Gas Target Model' that represented a shared vision on gas market design and that provided a 'certain' guidance to foster regulatory convergence where discretion existed in EU rules in the absence of more prescriptive ones. It played a complementary role next to legislation. However, such voluntary cooperation is not conducive to remove barriers, to provide for appropriate levels of harmonisation or certainty to the market and legislation is needed to address the identified problems in a consistent way.

Stakeholders' opinions: In the public consultation a large majority of respondents support the introduction of regulation to foster a well-functioning and competitive hydrogen market and hydrogen infrastructure. None of the respondents stated that there is no need for regulation at all. Whist stakeholders had diverging views on how this should be done, a majority takes the view that LCH and LCFs should be defined and that the claims about their contribution towards decarbonisation should be verified.

5.1.2.2 Option 1: Rights for network operation tendered

As under BAU, there are no rules or restrictions at EU level on the ownership or operation of infrastructure, or its financing. However, under this option Member States would tender the rights for investments in and the operation and ownership of future hydrogen networks to market participants (including existing gas TSOs). The successful bidder would be granted a regional monopoly position, e.g. on national level or for a local network within Member States or, possibly even, for a specific pipeline or other type of infrastructure, under which the bidder could build and operate it and supply hydrogen customers or, if it chooses to do so, offer infrastructure usage to third parties. The tendering may include conditions or principles set *at national level* to reflect certain public interests. However, these will not be harmonised by EU rules.

This option thus represents a form of ‘competition for the market’. Concession holders may or may not have interests to foster cross-border interconnection and interoperability, including e.g. ensuring that acceptable and required hydrogen purity levels are addressed[95] , to the extent this is compatible with their business interests, which can include upstream and downstream business.

Stakeholders' opinions: In the public consultation, only a minority of respondents supported this option. Respondents who supported the introduction of regulation for hydrogen markets and networks, stated that a suitable regulatory model should be developed at EU level rather than at national level.

5.1.2.3 Option 2: Main regulatory principles

This option entails the introduction of main regulatory principles that are inspired by those that are applicable to the natural gas (and electricity) markets. Option 2 in essence represents a choice for a ‘competition in the market’ approach (as opposed to a ‘competition for the market’ under BAU and Option 1), but regulation does not have the same depth and scope of the market design of the mature natural gas market. Option 2 reflects a more modest, first step approach.

Under this option, the natural monopoly character of hydrogen networks is countered through rules that impose constraints on its owners. These include the unbundling of transportation from supply and production activities (vertical unbundling) and rules that govern access for third parties (TPA). Cross-border integration is fostered by communality of main regulatory principles but also specific ones, such as rules on the quality of hydrogen at cross-border points or a rules on common EU terminology and certification system for LCFs/ LCH). Similarly, repurposing infrastructure is facilitated to a degree by EU rules. Hydrogen infrastructure can be developed by both private investors and regulated entities, like todays TSOs.

The main regulatory principles would necessitate corresponding powers and competences of national regulatory authorities (and, where appropriate, of ACER) to ensure adequate implementation and monitoring at national level.

Stakeholders' opinions: A large majority of respondents supports the ‘competition in the market’ approach and believe that a common approach is needed to define key regulatory principles (such as neutrality of network operation, third party access, cost reflective and market compatible network tariffs, treatment of private networks) as networks can represent a natural monopoly, even if stakeholders have different views on the depth and scope of the rules needed. A step-wise approach is largely supported.

Under Option 2: two sub options are distinguished that both share the characteristics set out above but are different with regards to the requirement they impose on market participants and the degree in which they provide guidance or define a longer term perspective on the regulatory framework for hydrogen infrastructure and markets. I.e. they represent different manifestations of a step-wise approach based on main regulatory principles.

5.1.2.4 Option 2a: Main regulatory principles only

Whilst inspired by the rules for the natural gas sector, under option 2a the main regulatory principles are adapted to the specificities of a developing hydrogen value chain. Under sub-option 2a, **existing**

[95] E.g. in agreements for the cross-border hydrogen transport.

natural gas TSOs are relatively unconstrained in being involved in and build out a hydrogen network, including through repurposing the natural gas assets they currently manage.

In order to ensure the emergence of a competitive market structure, **negotiated TPA to hydrogen networks and large scale hydrogen storage** is introduced**.** Negotiated TPA provides flexibility in infrastructure financing options (relative to regulated TPA). **No TPA at all is required for hydrogen import terminals** to reflect the fact that, as the means by which hydrogen and its derivatives can be imported are wider in scope than for today's natural gas terminals, it is more likely that import terminal operators will be subjected to effective competition and less need for regulation exists. Large volumes of imports do not exist yet by 2030 under the scenarios used. Gas TSOs can operate hydrogen networks under the same rules for **vertical unbundling** as in the natural gas sector.

Some measures are taken to **facilitate investments in *existing* infrastructure** by stimulating the grandfathering of existing rights and permits of methane infrastructure when repurposed to hydrogen infrastructure. Gas TSOs can finance and de-risk hydrogen infrastructure investments by using (regulated) revenues from the natural gas side of their business (including revenues collected through cross-border tariffs from network users in other Member States) without constraints (**joint-RAB**). **Private parties** can invest and operate hydrogen infrastructure under exemptions. Such investments can take place without specific measures that ensure a future convergence on a single regulated regime within a progressively inter-connected hydrogen network.

Cross-border operation, in particular **hydrogen quality**, is assured by the same rules as those that exist today for natural gas, including a dispute settlement procedure with the involvement of the concerned regulatory bodies. For **LCH and LCF**s, a common EU terminology and a light GOs based certification system for LCFs/ LCH) would be introduced

There are **no specific consumer protection rules** beyond the main regulatory principles (such as TPA) reflecting that early users of hydrogen are larger, more sophisticated consumers, unlike the more varied customer base for natural gas (that also includes SMEs and households).

Stakeholders' opinions: A significant majority of stakeholders consider it very important that **TPA** to dedicated **hydrogen network** is set at an early stage (but their preference is for regulated TPA). Most stakeholders consider that, appropriate measures are now required on imports and a significant majority supports **rules for access to hydrogen import terminals**. A large majority of respondents consider it important or very important to define market **rules for access to storage for (pure) hydrogen** at an early stage and it should entail a choice between negotiated and regulated access. The vast majority of stakeholders consider it important or very important to set rules at an early stage to ensure the neutrality of hydrogen network operations (i.e. **vertical unbundling**) and that network operations should be in a distinct legal entity (coherent with the current Independent Transmission Operator ('ITO') unbundling model) or ownership unbundled. With regard to **repurposing**, a majority of respondents consider it necessary to clarify whether rights of land use, private easements as well as the validity of public permits that have been granted for the construction and operation of methane gas pipelines continue to be valid when these are used for hydrogen

Respondents are divided on whether cross-subsidies between hydrogen and natural gas transport activities should be allowed (**separate versus joint RAB**). Half of the respondents (mainly incumbent natural gas TSOs, DSOs and industrial energy consumers) are in favour of (partial) cross-subsidisation to ensure the development of dedicated hydrogen networks.

Most respondents considered it important or very important to define early the role **of private parties** in developing hydrogen infrastructure. However, few supported that this should be done unconditionally and without ensuring regulatory convergence. A quarter of respondents specifically support establishing **hydrogen quality (purity)** standards at Member State level with EU-level cross-border coordination rules. There is strong support for establishing rules on roles, responsibilities and cost-allocation for the management of hydrogen quality at EU-level.

With regard to **LCHs and LCFs**, answering to a poll during the first stakeholder workshop, 38% of the respondents took the view that the RED II certification scheme should be extended to LCH and LCFs. 23% of the respondents think that GOs should become the only verification of a compliance system.

Very few stakeholders support the view that the main regulatory principles by themselves provide sufficient **consumer protection**.

5.1.2.5 Option 2b: Main regulatory principles with a vision

Option 2b is similar to 2a in that it is built on the main regulatory principles governing the current natural gas market. However, it seeks to provide more guidance as to the direction into which the regulatory framework will develop in the future whilst retaining flexibility in the transition in order to take account of the emergent nature of the hydrogen value chain today and the uncertainties surrounding its development. It also takes better account of some of the lessons learnt from the liberalisation of the gas and electricity sectors and takes advantage of the fact that it is possible to take a 'greenfield' approach to regulation, in which choices aimed at creating a competitive market can still be made unconstrained by an entrenched factual or regulatory situation (unlike when liberalising the than already mature gas and electricity markets). Thus, while still representing a light regulatory regime based on the main regulatory principles as the natural gas market, Option 2b takes the adaption to the characteristics of the hydrogen value chain a step further and provides more guidance as to its future in comparison with Option 2a and represents a real step-wise approach.

Like under Option 2a, under option 2b the natural monopoly character of hydrogen transportation infrastructure is countered through rules that impose constraints on infrastructure owners. With regard to **TPA** to hydrogen networks (including cross-border interconnectors and interconnections with third countries) a stepwise approach is envisaged where negotiated TPA remains possible during a transition phase to provide flexibility (like under Option 2a) but where regulated TPA and tariffs would be phased-in later. Learning from the past, it seeks to avoid the 'pancaking effect' that currently characterizes the natural gas system by prohibiting cross-border tariffs, thereby setting the stage for an EU hydrogen market with a true level playing field later. For **large-scale storage**, Option 2b entails a relatively strict regime of regulated TPA from the start. In view of the intermittency of renewable hydrogen production but the need to provide stable supply to (industrial) users, access to storage will be commercially crucial for hydrogen producers. However, large-scale storage will be scarce (especially at the ramp-up stages) and available only in certain Member States, due to geological conditions. **Import terminals** will under Option 2b not be left fully unregulated (like under Option 2a) but subject to a relatively light regime of negotiated TPA. To benefit from the 'greenfield' nature of hydrogen infrastructure regulation and the fact that vertical integration today is rare, a stepwise but relatively strict approach is taken under Option 2b with regard to **vertical unbundling** of networks. In the transition phase, the ITO model can still be used by the current natural gas TSOs that want to repurpose their assets for hydrogen transport. However, after this transition phase, hydrogen network operators are either ownership unbundled or the networks of vertically integrated operators are governed by an independent system operator (ISO)[96], which can already be made available in the transition phase but is than not yet obligatory.

Like under Option 2a, **private investors** can invest and operate infrastructure. However, guarantees are built in to foster convergence and avoid the persistence of divergent regulatory regimes within the later inter-connected network. Existing private networks can also opt-in into the regulated system.

[96] The ISO model could be available already for vertically integrated companies in the transition phase, but will than not yet be obligatory in the transition

Facilitating networks development will not only be done by facilitating the **repurposing of *existing* infrastructure** (like under Option 2a), but also by ensuring that permitting and land-use rights for ***new* infrastructure** at national level are at least equivalent to those applicable for natural gas infrastructure. This to avoid bias in the feasibility of infrastructure projects and lock-in. With regard to the asset base of regulated entities, the default rule is a separation of hydrogen and gas network asset bases **(separate RABs)** and cost-reflective tariff setting**.** However, flexibility is provided by an option of (temporary) financial transfers between the natural gas and hydrogen asset base (financed by domestic natural gas network users only and subject to conditions). This allows cost-reflective tariffs setting but also hydrogen network operators to stabilise tariffs for hydrogen network users in the ramp-up phases of a hydrogen network whilst avoiding that this is paid for by network users in other Member states. This approach implies the need for (at least) **horizontal accounts unbundling** between natural gas and hydrogen network activities..

Using the green field nature of hydrogen infrastructure regulation and the fact that technical standards already exist for hydrogen end-applications, Option 2b establishes an **EU-wide acceptable purity level** for cross-border points in order to foster cross-border interoperability. Further, this option would include cross-border dispute settlement tools and increased transparency as under option 2a. With regard to LCH and LCFs, this option also provide a common terminology but (unlike Option 2a) certification will be based on life-cycle analyses and a mass-balance approach through voluntary schemes.

A **light regime of consumer protection** rules will exist, reflecting the fact that early users of hydrogen are likely more sophisticated and need less protection. It will be aligned with those valid for the natural gas system in order to make sure that switching decisions are made on the basis of economic opportunity as opposed to regulatory bias.

Stakeholder's opinions: A large majority of respondents supports the principle of regulated **TPA** to networks. EU legislation ensure non-discriminatory access to network users on the basis of published terms and conditions, including approved or set tariffs by the national regulator. A significant majority of respondents considers the current structure of cross-border gas transmission tariff system suitable for the hydrogen market. A large majority of respondents consider that rules for dedicated **hydrogen storage** are necessary to the same degree as for methane storage. A significant majority of stakeholder supports rules for access to hydrogen **import terminals**. About half of the respondents in favour of requiring **vertical unbundling** think that ownership unbundling should be applied at EU level from the start. A large majority of respondents takes the view that network operators should never own or operate power to gas installations or only under very strict conditions[97].

Few respondents consider that <u>existing</u> **private network operators** should remain fully unregulated. A large majority of respondents consider that they may be exempted from certain regulatory requirements, but only temporary. Some take the view that private operators should be given a unilateral possibility to 'opt-in' into an existing regulated system. Few consider that <u>future</u> private networks should be left unregulated. A large share of respondents considers that the default rule should be that they are regulated but that exemptions can be considered under conditions.

The vast majority of respondents considers that **rights and permitting requirements for new hydrogen infrastructure** should be similar to those applicable to methane gas pipelines today. Respondents are divided on the allowance of cross-subsidies between hydrogen and natural gas transport activities (**separate versus joint RAB**). Half of the respondents, mainly representing NRAs,

[97] For example, only if this is necessary to guarantee network operations and if no other market party is willing to carry out the investment. Clear and limited conditions should be defined (e.g. limitations in scope, scale and time), after it has been proven that the market is not willing to invest in such installations and foreseeing a procedure to transfer such installations back to a market-based regime once the derogation expires) or that this choice should be left to Member States

some consumer organisations, NGOs and some industrial energy consumer and stakeholder associations want rules ensuring that hydrogen pipelines are being financed by network users only.

Half of the respondents support establishing an EU-level binding **hydrogen quality standard**.

With regard to **LCHs and LCF,** 38% of the respondents took the view that the RED II certification scheme should be extended to LCH and LCFs. The panelists acknowledged the necessity to have a certification system, including for LCH and LCFs, across the life cycle and indicated the importance of the REDII certification system to cover all fuels, including LCH and LCFs.

Half of respondents consider it important that typical first users of a hydrogen network (from the industrial and transport sector) have the same **consumer protection rights** as if they would be connected to the methane gas grid in order to ensure a level playing field[98].

5.1.3 Option 3: Big Bang

Option 3 is designed to reflect a situation where a separate regulatory regime for hydrogen would exist and which would be similar (including the role of NRAs and ACER) to the one currently applicable to the natural gas sector, based on 'competition in the market', without much need for a transition. Adaptations are however made to the characteristics of the hydrogen value chain, to exploit lessons learned from the liberalisation of the gas and electricity markets and 'green field' opportunities. This option reflects a preference for immediate clarity or 'big bang'.

Stakeholder opinions: Whilst a large majority of respondents want a regulatory framework that reflects 'competition in the market' approach, most of them prefer a stepwise approach (as embodied in Options 2 and 2b). Only a minority favours regulation with detailed EU rules (implementing regulatory principles and technical rules) from the very start.

5.1.3.1 Sub-option 3a: Hydrogen rules by Big Bang

Sub-option 3a reflects a roll-out of a regulatory framework closest to the current gas-market regulatory framework for gas, but largely separately. Gas TSOs would be able to operate as hydrogen TSOs but these would need to be operated as businesses that are both financially (separate **RABs**) and organisationally (legal and functional **horizontal unbundling**) fully separate. Activities in downstream and upstream hydrogen (and other) activities would be excluded by **ownership unbundling**.

Existing **private** hydrogen network operators would not be able to continue their current business model but would need to be ownership unbundled. Only *new* **private** infrastructure may be exempted (like under the current gas directive) and thus not be possible for already *existing* networks.

Importantly, to foster market integration, option 3a would include (**detailed, technical) rules** on capacity allocation and congestion management at cross-border interconnection points in hydrogen networks and balancing and cross-border operability and tariff setting currently at least partially contained in the technical rules (so-called network codes) for the natural gas market.

Repurposing and the building of existing new infrastructure would be facilitated but through more decisive steps i.e. by harmonising at EU level permitting and land-use rights.

Consumer rights for hydrogen will be fully aligned with this in the gas and electricity sectors, including for SMEs and households.

[98] According to a large majority of respondents, such rights should include consumption data, billing information, supplied hydrogen quality, CO2 content of hydrogen supply, switching rights and dispute settlement.

Like under Option 2b, cross-border tariffs are rendered impossible to avoid pancaking, an EU-wide acceptable **hydrogen quality** for cross-border points is set. **Access rules for large-scale storage and import terminals and terminology** and **certification of LCH and LCF** are also the same as under Option 2b.

Stakeholders' opinions: Half of the respondents supports the requirement of vertical **unbundling** and state that ownership unbundling should be applied from the start. Whilst only a minority favour **detailed technical** EU rules from the very start, a large majority[99] of stakeholders consider important to have these at an early stage. Only a small minority thinks that existing **private infrastructure** should *not* have a special treatment and that main regulatory principles should apply to all networks immediately. About half of the respondents prefer **consumer rights** fully aligned with those for natural gas consumers, regardless their size (i.e. households) and use of hydrogen.

5.1.3.2 Sub-option 3b: Hydrogen rules by Big Bang plus

Option 3a and 3b are rather similar but Option 3b introduces also the creation of an EU hydrogen TSO tasked with operating and developing an EU hydrogen network whilst the actual ownership of the pipelines remains with the national TSOs (**EU ISO model**). In this regard it takes a yet more extreme option by replacing, in operational terms at least, national TSOs and create an EU network operator. It would addresses conflicts of interests resulting from vertical and horizontal integration. On the other hand, it offers an opportunity to avoid full ownership unbundling (like under Option 3a) for vertically integrated companies. It can also have synergies with some options for other main regulatory principles.

Stakeholders' opinions: A majority of the respondents are against the introduction of an **EU TSO (ISO model)** for hydrogen because the coordination of infrastructure can be managed by integrated network planning and the model would be disproportionate to establish a well-functioning hydrogen market.

5.1.4 Options discarded at an early stage

The **option 0+ of stronger enforcement and voluntary collaboration** was not further assessed as it would not provide appropriate levels of harmonisation or certainty to the market. Stronger enforcement is impossible as currently no rules exist, let alone rules that can be enforced stronger. It was initially considered to develop options to amend the **electricity market rules** to ensure that electrolysers, which are present at the demand side of the electricity markets, can fully participate therein. However, no clear needs to modify the Electricity Directive and Regulation were identified. Certain stakeholders have suggested a form of '**dynamic regulation'**. National Regulatory Authorities ('NRAs') should decide when possible regulation of hydrogen networks should kick-in based on periodic market monitoring focused on an assessment of the market circumstances that increase the risk of abuse of dominant position by hydrogen network owners. Intervention, if and when required, should be based on pre-defined EU-wide regulatory principles. This option was assessed but eventually discarded due to the expected disadvantages of the proposed approach of *ex post* regulation, in particular the lack of legal certainty for the required investments in hydrogen facilities and infrastructures with long life cycles and depreciation periods. Moreover, the resulting risk of regulatory fragmentation across different Member States may have a detrimental effect on network interconnectivity and the integration of national hydrogen markets and thereby on cross-border trade and market development.

[99] With the exception of technical rules on tariff setting, which was only supported by approximately half the respondents.

Stakeholders' opinions: The option of 'dynamic regulation' as supported by a small and diverse minority of respondents. The large majority of respondents preferred clear ex-ante rules (even if they had different opinions on the depth of such ex-ante rules).

5.2 Options in the problem area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

The options in this section area address the problem in area II, namely the untapped potential of renewable gases and barriers in the existing framework. Each of the options addressees all the drivers described in section 2.2 of this Impact Assessment with increasing depth of the intervention.

5.2.1 Baseline

While in the baseline no further legislative measures at the EU level would be adopted, new developments would arise from the measures foreseen in the 3rd energy package, from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels.

In the baseline, **access of renewable and low carbon gases** to the markets and infrastructure might remain hindered and a patchwork of various provisions will persist among the Member States. TSO-DSO coordination rules on connection requests are absent in around half of the Member States at least. Access to wholesale markets for biomethane producers may remain restricted in some Member States. Moreover, even in countries where entry-exit or balancing zones include the DSO level, the lack of reverse flow capacity will most likely constrain production and trade of biomethane. Tariffs at intra-EU interconnection points would still be applied to the transport of biomethane, in the current range of 0.15-2 EUR/MWh (commodity-based equivalent tariffs)[100], except in integrated balancing zones. Such zones exist currently at regional level (FI-EE-LV, DK-SE and BE-LU markets). By 2030, additional mergers could occur, but tariffs would still be in place for most intra-EU interconnection points.

Cross-border management of **gas quality** and information sharing would rely on existing procedures defined in the interoperability and data exchange network code. The CEN standard for H-gas (*natural gas*), EN 16726, would be revised to include the Wobbe Index[101]. Other EN standards for hydrogen and hydrogen blends in the network and in end-use would be developed.[102] However, these standards would remain non-binding and their application cross-border would not be aligned. In addition, gas quality specifications would continue to be mainly defined by the quality parameters of natural gas. Rules on **hydrogen blending** levels would remain national, without any cross-border alignment. However, voluntary cooperation between adjacent TSOs across Member State borders could take place on blending thresholds.

LNG terminals operations would depend on the decisions of the national authorities and the development of the LNG market. It can be expected that voluntary initiatives by the LNG sector would address some of the identified problems. The possibility to provide network entry tariffs

[100] The tariffs are based on the data from the 2020 TYNDP, which assumes a 100% utilisation of the IPs for converting any capacity-based tariffs into commodity-equivalents. Therefore, actual equivalent tariffs may be higher, as e.g. a 50% utilisation would mean the actual commodity-equivalent of a purely capacity-based tariff is twice as high. Moreover, for shippers with booked capacity, the tariffs are actually sunk costs. Therefore, capacity already booked should not influence shipper's decisions.
[101] The Wobbe Index is an indicator of the interchangeability of natural gas and is frequently defined in the gas quality specifications for e.g. injection or transportation of natural gas. It is used to compare the combustion energy output of different composition gases used in an appliance (e.g. turbine, boiler).
[102] (CEN – CENELEC 2019)

discounts to LNG terminals would remain, and thus existing discounts to terminals would in principle also remain. In the baseline however, LNG imports could remain restricted to natural gas.

Long-term contracts may continue to be prolonged or signed for periods exceeding 20 years. The climate policies, in particular the increase of the price of ETS certificates may diminish the incentives for importers to sign such contracts. However it is not excluded that a situation of stranded long-term contracts may occur. Companies holding such contracts may engage in practices to lower the price of natural gas, increasing the need for higher support of renewable alternatives.

The current framework on energy security result from the Regulation on security of gas supply[103] , which aims at guaranteeing the secure supply of natural gas. There would be no Union emergency mechanism to deal with the specific needs and threats of the decarbonised gas sector.

5.2.2 Description of the policy options

This section describes four policy options, each composed of a combination of individual policy measures and addressing the problems identified in Chapter 2 to different extents.

5.2.2.1 Option 0: Business as Usual (BAU)/No regulation

In the baseline, none of the EU-level policy measures for the Problem areas are in place. New developments would arise from the measures foreseen in the 3rd energy package and Regulation on gas energy security, from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels.

Stakeholders' opinions: Stakeholders in the public consultations agree on a need to revise current regulatory framework (Gas Directive and Gas Regulation) to help to achieve decarbonisation objectives, and on the need to align the SoS Regulation.

5.2.2.2 Option 1: Allow renewable and low carbon gases full market access

Option 1 includes policy measures that provide **access to markets and infrastructure** for renewable and low-carbon gases injected at the distribution or transmission level, and promoting cooperation between Member States. The detailed measures include requirements to including the distribution level into the definition of the entry-exit zones and requiring network operators to ensure physical reverse flow capabilities. Establishing a gas specific DSO coordination as part of the DSO-entity from electricity sector may help to facilitate coordination between TSOs and DSOs in this option.

As regards the **gas quality regulatory framework**, this option provides for a reinforced cross-border coordination between Member States on gas quality issues, building on the existing cross-border dispute settlement process (Interoperability Network Code). It strengthens the role of the National Regulatory Authorities and, where relevant of ACER, for cross-border issues related to gas quality and for monitoring related developments to increase transparency.

As regards **hydrogen blends**, this option includes an obligation on Member States to define a national acceptable hydrogen blending level. While under this option Member States would still have the possibility to define the acceptable blending levels as zero (as current practice in some Member States), this would provide for a clear overview and increased transparency of the applicable specifications across the EU.

Voluntary (e.g. industry-led) initiatives to improve transparency for **LNG terminals** would be encouraged without however a legal obligation.

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The Commission would issue one or several recommendations to Member States and stakeholders on **extending the scope of the energy security tools** to new gases and risks and the minimum cybersecurity requirements for the gas sector.

Stakeholders' opinions: A majority of stakeholders in the public consultation consider it important to ensure full market access and facilitate the injection of RES&LC gases into the existing gas grid. A majority supports as well the improvement of the transparency framework for LNG terminals. There is also a strong support for the harmonised application of gas quality standards across the EU, for reinforced cross-border coordination and increased transparency. Respondents are more divided on hydrogen blending. The majority agree that it provides a cost efficient and fast first step to energy system decarbonisation. However, a quarter of respondents underline that blending prevents the direct use of pure hydrogen in applications where its value in terms of GHG-emission reductions is higher and that it creates technical problems and additional costs at injection and end-users points. Over a third of the respondents support setting national hydrogen blending levels in a standardised way. Some stakeholders advocate to create an EU DSO for gases similarly to the single EU DSO established in the electricity sector.

5.2.2.3 Option 2: Promote market access and security of renewable and low carbon gases

Compared to option 1, option 2 would add an obligation for network operators to **connect renewable and low-carbon gas** producers (with a firm capacity assurance), and introduce a reduction or exemption of injection charges to those producers in order to reflect the system benefits (i.e. avoided network costs) and climate benefits.

As regards the **rules on gas quality**, this option includes in addition to option 1, setting EU rules for processes, roles, responsibilities, cost recovery and cost allocation of gas quality management as well as for reinforced regulatory oversight. This could either be set on the basis of high-level EU principles defining the different aspects of gas quality management – and thereby allowing Member States more flexibility when developing national implementation – or through concrete and detailed EU rules.

As regards **hydrogen blending**, this option defines an EU-wide allowed cap at cross-border interconnection points, meaning that TSOs would be obliged to accept blending levels that are below the cap at interconnection points. They might accept higher blends on a voluntary basis, but there would be no obligation to do so. The rules would not propose mandatory blending and leave the flexibility to Member States to set blending rules if they wish so for the domestic network.

As regards **LNG terminals**, this option includes a binding legal framework at EU level for transparency, congestion and access rules (secondary capacity).

This option would also include **energy security** rules ensuring that risks and needs related to renewable and low carbon gases are duly taken into account in the energy security Regulation, in particular concerning (a) the compliance with the infrastructure standard; (b) the risk assessments (to accommodate relevant new risks incl. climate change), (c) the national plans and the bilateral solidarity arrangements between Member States (to clarify the applicable technical and financial conditions of solidarity gas) and (d) adopting harmonised cybersecurity rules specific for the gas sector. The future gas sector would be integrated in the broader stepwise development of the EU policies on the protection of critical energy infrastructure. Cybersecurity and physical protection would converge, by improving communication, coordination and collaboration.

Stakeholders' opinions: Many stakeholders advocate an obligation for network operators to connect RES&LC producer and introduction of an injection charge reduction. Few stakeholders ask for stronger promotion measures such as targets or quotas for RES&LC[104]. A quarter of respondents support setting a harmonised EU-wide allowed cap for hydrogen blends, which TSOs must accept at cross-border interconnection points. One third is supporting national blending rules. The majority of respondents support establishing EU-level principles for rules on roles and responsibilities for gas quality management for the Member States. Stakeholders agreed on the relevance of the energy security challenge in the context of the gas decarbonisation. Majority of the respondents consider gas specific cyber-security measures as important.

5.2.2.4 Option 3: Allow and promote renewable and low carbon gases full market access, and security, and tackle issue of long term supply natural gas contracts

In addition to option 2, **option 3** would remove privileges (derogations) for **new long term natural gas contracts** and limit duration of such contracts to 2049.

The **pancaking effect** (see section 2.1.3.3 for explanation) would be addressed **for renewable and low carbon gases only** abolishing cross-border tariffs on all interconnection points as in option 4. This tariff discount may be conditioned upon their carbon footprint. Rules enhancing transparency of allowed revenues and costs benchmarking will address the existing outliers of cross-border tariffs. Regional cooperation will be supported by a Commission guidance. Measures to increase **access to LNG terminals** and gas storages for renewable and low-carbon gases, including through improvements in the legal framework for transparency and third-party access rules. Long-term contracts for natural unabated gas will be forbidden as of 2050.

Stakeholders' opinions: Some stakeholders argued for measures that dis-incentivise the use of unabated fossil gases. Moreover, a few did directly highlighted that long-term contracts can foreclose the market.[105] Other stakeholders do not see the abolishment of special treatment for natural gas LTCs as important.[106]

5.2.2.5 Option 4: Allow and promote full renewable and low carbon gases market access, and security, tackle issue of long term supply natural gas contracts, remove border tariffs and set EU gas quality standard

In addition to option 3, in **option 4,** all intra-EU cross-border tariffs for uncongested interconnection points are eliminated.[107] Internal entry tariffs for renewable and biomethane gases would also be set to zero, as well as tariffs from/to storage. Pipeline tariffs would be determined based on the capacity-weighed distance to a point in the centre of Europe, with entry tariffs for LNG terminals being set to zero (as a variant, non-zero tariffs to LNG terminals could be determined with the same method as for extra-EU interconnection points). The missing money arising from setting intra-EU cross-border and some internal tariffs to zero would be recovered from internal exit tariffs to end-consumers, possible increases at EU-external tariffs, possible revenues from congested points and an inter-TSO compensation mechanism set-up in order to re-allocate revenues.

[104] See for example the Public Consultation answers of Eurogas.
[105] See for example the Public Consultation answers of EEX.
[106] See for example the Public Consultation answers of CEER.
[107] For storage, tariffs are considered to remain unaltered. Biomethane is supposed to rely on public support and being produced in any case (and at any cost including tariff) in all scenarios. Other renewable gases are not explicitly considered.

As regards **long-term contracts,** additional steps would be introduced limiting duration of the contracts well before 2049. For instance, contracts for supply of unabated gas signed as of 2030 could not exceed 10 years duration, unless abatement takes place.

Regarding **gas quality**, this option entails EU-level harmonisation of the technical gas quality standards applicable at cross-border interconnection points. This would mean a continuation of using the quality specifications of natural gas as a basis to define quality standards for the whole EU gas network (e.g. by codifying the CEN standards for H-gas in EU legislation). A variant under this option is to harmonise gas quality standards at EU-level based on the quality specifications for biomethane applicable at cross-border interconnection points. In addition, this option cumulates relevant elements of option 1 and 2 for gas quality, namely reinforced cross-border coordination, rules for processes, roles, responsibilities, cost recovery and cost allocation of gas quality management as well as for reinforced regulatory oversight and increased transparency.

As regards **hydrogen blends**, this option sets a harmonised EU-wide allowed cap and a higher maximum threshold for hydrogen blends at cross-border points. This would mean that TSOs would be obliged to accept blends that are below the lower cap at cross-border points and would not be allowed to accept blends that exceed the maximum allowed threshold. This would avoid, that the costs of one Member State's blending pathway have to be covered by adjacent Member States (cost of adapting their infrastructure and end-use appliances to higher blending levels).

Stakeholders' opinions: Few stakeholders in the public consultation supported an option to remove intra-EU cross-border tariffs. Many respondents were, however, sceptical about such solution arguing that that current cross-border tariff setting is satisfactory and does not require fundamental design change. While there is no majority for defining an EU-level binding gas quality standard, even those supporting this option are divided. A third of them support such a standard based on the quality standard for natural gas, while another third support a standard taking fully into account renewable and low-carbon gases.

5.2.3 Options discarded at an early stage

An additional option considered would not aim at facilitating or promoting access of renewable gases to the internal gas market. Instead, in the expectation of increasing importance of locally produced biomethane in the EU, this option would contain measures merely focusing on incentivising the injection of local renewable and low-carbon gases at the distribution level. The wholesale market and transmission level would remain dominated by natural gas, until its use diminishes.

Measures included in this option would include the obligation for network operators to provide a connection with associated firm capacity to producers, and for Member States to provide exemptions or reductions of injection charges for renewable and low-carbon gases – as in options 1-4 above. Moreover, specifically for this option, measures facilitating energy communities would be in place, particularly allowing them to supply and trade gas locally. Gas quality measures would be limited to reinforced cross-border coordination and transparency on gas quality and on national hydrogen blending rates, similarly to option 1. Likewise, measures for LNG terminals and storage would be limited. An option for Member States opting for a negotiated access to the LNG terminals could be introduced (as currently is possible for gas storages).

This option **is discarded** as it is difficult to reconcile with the main objectives of the initiative i.e. facilitating decarbonisation of the gas market, at all levels, and adapting regulatory framework so that decarbonisation takes place on the basis of competitive, integrated market. It would also run against the recommendations of the Hydrogen Strategy and Sector Integration Strategy which set out how the energy markets could contribute to achieving the goals of the European Green Deal. Biomethane development at the distribution level would be driven exclusively by energy communities and local production, promoted by specific policy measures.

In this option the biomethane production levels would be lower than in the MIX-H2 scenario, even if specific Member States may achieve or exceed those levels in 2030. New biomethane plants would be connected mainly at the DSO level without however access to the wholesale market and transmission grid. The drivers and problems identified in section 2 would therefore not be addressed. The lack of reverse capacity between DSO and TSO, may restrict the capacity of biomethane that can be connected to distribution networks with low local gas demand.

The aggregated biomethane production levels are lower than in the MIX-H2 scenario. Nevertheless, some elements of this option, such as in particular the energy communities will be further considered for the legislative process to enable adjustment of the supply of biomethane to the local needs and conditions and facilitate consumer’s choice for renewable gases. This would allow to tackle problems identified in area IV

Stakeholders' opinions: A vast majority of stakeholders was not in favour of this particular option in the public consultation pointing out inter alia that decarbonisation shall take place on the basis of competitive and integrated market, not solely a local one. Regarding the more specific measure associated in this option, some stakeholders strongly support the adaptation of energy communities to gas to align it to the electricity framework.

5.3 Options in the problem area III: Network planning

Integrated planning practices at all levels will be needed in order to ensure the achievement of energy and climate policy objectives at the lowest cost, while maintaining security of energy supply. The below options include measures to increase the level of planning integration. The options build up on each other, i.e. the elements described in option 1 are also part of option 2 and those of option 2 are part of option 3. Guaranteeing coherence with the relevant provisions of the SoS Regulation (e.g. Union wide simulation of disruption scenarios, national/regional risk assessments) is a common element to all options.

5.3.1 What is the baseline from which options are assessed?

No further EU-level legislation would be developed regarding **integrated network planning.** National plans are to be developed only in Member States where ITO and ISO certified TSOs are operating. While most Member States that have a single gas NDP within which gas TSOs cooperate, there is still limited cross-sector cooperation.

5.3.2 Description of the policy options

5.3.2.1 Option 0: Business as Usual (BAU)

In the BAU option, there would be no change to the current situation.. Some Member States, national regulators and/or network operators may adopt additional measures.

Stakeholders' opinions: A big majority of stakeholders support the measures that are contained in any of the options below. Only a few stakeholders do not see a need for alignment or any other measure supporting sector integration.

5.3.2.2 Option 1: National Planning

This option requires a consolidated network plan including storages, LNG Terminals and production per Member State, irrespective of the unbundling model chosen and the number of gas TSOs in the country. Member State may also opt to develop a joint regional plan instead. The national network development plan needs to be drawn up every two years to align it with the TYNDP timing. The network plan remains binding only for ISO and ITO certified TSOs, which means no change to what is required by the current Gas Directive.

The NDP should include information to what extent and from what point in time certain methane infrastructure is not required anymore and could be used for other purposes. A sustainability indicator to be developed under the guidance of the NRA, should lead to preferring investments that allow gases with low or no carbon impact to be transported in the network.

Stakeholders' opinions: A good majority of stakeholders indicate support to align the timing of the NDPs with the TYNDP and require a single plan irrespective of the unbundling model chosen.

5.3.2.3 Option 2: National Planning based on European Scenarios

This option extends option 1 by requiring a joint scenario, built on the gas and electricity development plans and including the distribution system level. At least one scenario used for the national plan needs to be in line with the European Union climate targets and energy efficiency and renewable energy 2030 and 2050 targets. This can also be ensured linking it to the relevant National Energy and Climate Plan, which is required to be in line with the climate goals. Building joint electricity and gas scenarios would ensure that indirect interlinkages are treated in a consistent way in subsequent processes by TSOs, and that investment decisions are taken with a common vision of the future. The way direct interlinkages are taken into account can have an impact on the assessment of projects. This latter point is treated in Option 3.

Establishing joint scenarios at the Member State level would mirror the EU-level situation where ENTSO-E and ENTSOG are, since 2018, developing TYNDP scenario jointly. Although there would be still sector specific plans for project identification, the process leading up to the plans could be based on a conceptual integrated plan, or the draft plan should be cross-checked between the sectorson the consistency between the gas and electricity NDPs. This process will build on the collaboration between the electricity and gas TSOs that has to be established to build scenarios. The role of these sanity checks is to examine the potential inconsistencies resulting from the assumptions made by TSOs regarding technologies that are at the interface between the gas and electricity sectors (gas-to-power, power-to-gas, hybrid consumption technologies).

As regards hydrogen development planning, the NRA is empowered to require to perform a market test establishing the actual need for hydrogen pipelines. This can be done in a more flexible way also outside the bi-annual NDP to cater for a situation of an emergent market.

Several governance options are compatible with Option 2. They range from the production of a consolidated and integrated network planning document to the publication of sectorial NDPs produced using a concerted process.

Stakeholders' opinions: A significant majority of stakeholders support a joint electricity and gas scenario. Support was even stronger than for the elements contained in Option 1. Only a few stakeholders are against a joint scenario building. A significant number of stakeholders ask for the inclusion of hydrogen projects in the NDP. Stakeholders most preferred choice as regards the role of Distribution System Operators was to provide and share information. While several stakeholders also support that DSOs provide their own plan including system optimisation across different sectors.

5.3.2.4 Option 3: European Planning

This option would require the creation of a single system-wide network development plan at European level, covering all relevant energy carriers (electricity, methane gas, and hydrogen) per Member State. This system-wide TYNDP would furthermore need to consider investments and investment plans for unregulated energy infrastructures, such as district heating networks. This requires, inter alia, that the system operators provide their complete network information to ENTSOG to enable that the TYNDP can identify and assess projects on the basis of hydraulic modelling, while at the same time integrating and assessing the electricity side, both on TSO and DSO level.

Stakeholders' opinions: Asked about whether stakeholders prefer a joint scenario, but still separate plans, there was slightly more support for a joint plan than those supporting joint scenarios but separate plans. Several stakeholders pointed out that a joint methane and hydrogen plan, keeping a separate electricity plan would be the preferred option, while this was not being asked explicitly in the consultation.

5.4 Options in Problem area IV: Low level of customer engagement and protection in the green gas retail market

Each policy option consists of a package of measures that addresses the problem drivers in section 2.2 of this Impact Assessment with increasing depth of the intervention. They aim to tackle the existing competition and technical barriers to the emergence of new services, better levels of service, and lower consumer prices, whilst ensuring the protection of energy poor and vulnerable consumers.

5.4.1 What is the baseline from which options are assessed?

In the current scenario, the development of the decarbonised gas markets and its impact on consumer rights and protection is based on enforcing current rules to address the limited competition of the green gases retail market, linked to high levels of market concentration and other rigidities, and low levels of innovation.

5.4.2 Description of the policy options

In the summary table 45 of Annex 9, a complete overview of the policy options is provided.

5.4.2.1 Option 0): Baseline Scenario: Enforcement measures to better apply current rules

This option assumes that the future situation improves through enforcement measures following the development of the decarbonised gas market without further legislation. The Commission promotes better enforcement by tackling cases of the non-transposition or incorrect application of existing legislation, reinforced administrative cooperation with and between national authorities, capacity building and guidance such as interpretative notes on the existing provisions in the Gas Directive (e.g. on switching-related fees). Enforcement action is taken should Member States' interventions in price setting be either disproportionate or unjustified by the general economic interest or not compliant with the current EU acquis,[108] [109]

Stakeholders' opinions: a vast majority of respondents consider that there is a need to be more ambitious when it comes to a citizen and/or consumer focus in the legislation than what is currently encompassed. Only a small number of respondents believe there is no need to further upgrade.

5.4.2.2 Option 1): Non-regulatory approach to address competition and customer engagement through strengthened enforcement and soft legislation

The number of gas users and volumes of gas consumed will be falling over the next 10-15 years. In such a shrinking sector, both public and private actors may struggle to implement new measures. Under this option, the problem drivers are addressed without resorting to new legislation, while implementation and enforcement measures are topped up by intense consultations with Member States and issuing Commission recommendations on **price regulation** or billing information. Support to the EU Energy Poverty Advisory Hub is enhanced and as such the role of networks of expert organisations is strengthened to deliver better energy poverty solutions at local level. Similarly, the Commission strives to make the most out of the current framework for **'renewable energy communities'**. All **smart metering** provisions are placed in one single legislative act and **data management arrangements** remain with Member States.

[108] Article 3(2) of the Electricity Directive and of the Gas Directive.
[109] Section 7.1.1 of the Evaluation argues that the regulation of gas prices limits consumer choice, restricts competition, and discourages investment.

Stakeholders' opinions: There are no respondents who explicitly stated their preference for the non-regulatory approach. To an extent stakeholders on price comparison tools, information on switching possibilities and identified the need of the deployment of smart meters which could potentially be addressed without additional legislation.

5.4.2.3 Option 2: Flexible legislation addressing all problem drivers

Under this option, all problem drivers are addressed through new legislation mostly mirroring the provisions in the electricity sector.

The framework for **price regulation** is better defined and limited to household customers (including vulnerable and energy poor households) and micro-enterprises. With regard to the higher protection of vulnerable customers and energy poor households, the recast EED definitions and requirements are cross-referenced, as the EED becomes the reference framework for this area. This will result in a framework that is streamlined with the revision of the ETS and extension to buildings and transport and its accompanying Social Climate Fund, where the main focus is on structural investments while direct income support is allowed, but not favoured and will need to be temporary and lead to results.

The Social Climate Fund shall be directed to reduce the reliance on fossil fuels through increased energy efficiency of buildings, and particularly synchronised with the revised gas legislation as it directs investments towards decarbonisation of heating and cooling of buildings, including the integration of energy from renewable sources, to the benefit of vulnerable households, vulnerable micro-enterprises and vulnerable transport users. Decarbonisation targets will be further supported by the directing funding to ensure improved access to zero- and low-emission mobility and transport. Key principles and **data management rules** are put in place to mirror, where relevant, the respective provisions for electricity. This could include enhanced **smart metering** rollout *(Option 2b)* or even a deployment target. Customers would also be entitled to request a smart meter at their expense. Minimum requirements for **contractual conditions** are established in particular **contract termination fees** would be **restricted**. Other areas which would be mirrored include faster and free-of-charge switching and the enabling framework for **citizen energy communities**.

Stakeholders' opinions: the vast majority of the stakeholders support the introduction of new legislation mirroring provisions in the electricity market. Some emphasize mirroring of billing information and energy poverty provisions to ensure consumers are not paying the cost of switching to clean gas based options. Some consumer organisations would keep regulated prices for energy poor and vulnerable consumers. Almost half of all respondents want provisions on comparability of offers and accessibility of data, transparency, smart metering systems, and switching to be reinforced.

5.4.2.4 Option 3: EU Harmonization and extensive safeguards for customer addressing all problem drivers

One of the key conclusions in relation to addressing Problem Area 2 is that there is significant benefits from ensuring that the market for Renewable and Low Carbon Gases is “European” from the beginning. A European wholesale market should be complemented by a European retail market. Under this option, all problem drivers are addressed through new legislation that aims to provide extensive harmonisation throughout the EU. To improve competition, Member States phase out **price regulation** for non-vulnerable customers and energy poor households.[110] With regard to the higher

[110] However, similar to option 2, exemptions to price regulation are defined at the EU level for vulnerable customers and energy poor consumers, allowing a case-by-case assessment of the proportionality of exemptions to price regulation.

protection of vulnerable customers and energy poor households, option 2 is enhanced by additional gas specific provisions and stronger restrictions on disconnections[111].

Other notable elements include a standard consumer **data handling** model with standardised formats. The rollout of gas **smart metering** becomes mandatory throughout the EU. **Switching**-related fees are banned, including contract termination fees and the format and content of **energy bills** is significantly harmonised – notably on the renewable and low carbon gases. Gas **citizen energy communities** would be harmonised with a supporting framework similar to Article 22 of the Renewable Energy Directive.

Stakeholders' opinions: respondents did not explicitly discuss the harmonisation of the consumers' provisions and safeguards on the EU level. However, some stakeholders support the strengthening and harmonization of gas quality standards that would ultimately enable better and more accurate information for the consumers. Furthermore, certain stakeholders have mentioned that responsibility for data handling would adequately correspond to TSOs when it comes to establishing blending rules.

6 WHAT ARE THE IMPACTS OF THE OPTIONS?

6.1 Assessment of options for Problem area I: Hydrogen infrastructure and markets

6.1.1 Methodological approach

The assessment of the policy options combines **qualitative with quantitative elements**. The focus is set on 2030 and the assumption that a transport network will exist in light of the expected increase of hydrogen production and consumption in the MIX H2 scenario.

Firstly, a holistic, qualitative assessment is carried out primarily by drawing on lessons from the existing (and regulated) gas and electricity market. The impact of the policy options on the **future hydrogen market structure**, the level of **cross-border market integration**, on **investment incentives in hydrogen networks** and **aligned hydrogen quality is assessed**. These assessment criteria thus correspond to the drivers identified in section 2.1, which relate to the need to accommodate cross-border trade, the need for investment in infrastructure, the risks this may result in non-competitive market structures and hydrogen quality related issues. The administrative impact on business and public authorities is also assessed under economic impacts (and further detailed in Annex 3).

In view of the uncertainty on the actual development of the hydrogen value chain, the expected **environmental impact** of the policy packages is described in more general terms.

Secondly, the different policy options have been **translated into scenarios for the energy system** in order to model their quantitative impact. The quantitative assessment is performed in the METIS model. The scenarios are based on **the expected effect the policy packages will have on the development of (cross border) hydrogen transport capacity (network infrastructure) and costs**. The effect of different policy options on the development of (cross border) hydrogen transport capacity can only be identified **in terms of direction**, i.e. different regulatory measures that are part of the policy options can increase or decrease the likelihood that (cross-border) hydrogen infrastructure gets built. Quantitative indicators are then calculated for all scenarios. The key quantitative indicators calculated for each of the scenarios are **the effect on costs of hydrogen delivered and the full costs of hydrogen, which include the change in total energy system cost due to the deployment of hydrogen.** Cost of hydrogen delivered reflect the total cost for hydrogen production (renewable energy sources, electrolysers) and hydrogen infrastructure (storage and

[111] Including: i) before a disconnection from the first unpaid bill; ii) notice by competent authorities to customers at least two months information on sources of support; iii) and the possibility to delay payments or restructure their debts.

network). Total energy system costs cover all cost components of the energy system consisting of gas and hydrogen supply and electricity generation. Interpreting the results and the expected impact of the policy options thus requires a reflection on both the qualitative and quantitative assessment.

6.1.2 Qualitative assessment

Each option exists as a package of more detailed measures. For each of these detailed measures, advantages and disadvantages are also provided in the tables in Annex 6.

6.1.3 Impacts of 0: BAU/no regulation at EU level

6.1.3.1 Economic impacts

Without regulation, companies can invest in hydrogen pipelines and operate these pipelines with a large degree of commercial freedom. Accordingly, hydrogen producers may enter into long-term supply contracts with (industrial) hydrogen consumers (or groups of companies) and offer the whole service of hydrogen production, transport, and structuring/storage/balancing (no vertical unbundling rules). The partners could agree freely on commercial terms (no tariff regulation) and the vertically integrated company could act as the sole user of the pipeline (no TPA).

(Cross-border) market integration: Without regulation, pipeline networks will be developed in a bottom-up approach, which is likely to result in dispersed, uncoordinated network development across the EU. Unregulated (private) investors will build pipelines where this is most profitable and not primarily where (cross-border) hydrogen needs are most urgent in light of decarbonisation efforts. No regulation is assumed to lead to less cross-border integration of hydrogen transport infrastructure than in the case of cross border harmonisation of rules. Accordingly, cross-border integration cannot contribute to a reduction in hydrogen costs by reallocating renewable hydrogen production to the most favourable production sites. The lack of EU approach on terminology and certification system hampers cross-border trade in LCH and LCF.

Investment incentives (new and repurposed infrastructure): The commercial freedom to enter into long-term agreements and secure investments at bilaterally agreed-upon terms may facilitate investments in an early phase of hydrogen market development, where there is not a solid customer base to socialise high initial costs. This holds for investments in new pipelines and investments required to repurpose natural gas pipelines for hydrogen.

Market structure: Under Option 0, owners of infrastructure having the characteristics of a natural monopoly are unconstrained and no regulation avoids the risk of charging monopolistic priced network tariffs and/or conduct resulting in market foreclosure. Market foreclosure of upstream (hydrogen producers) and downstream (hydrogen consumers) markets can easily result in monopolistic prices being passed-on down the entire hydrogen value chain with negative implications for hydrogen uptake and ultimately the achievement of decarbonisation targets. Additional consumers will only be connected if that is commercially attractive for the network owner. It is likely to require ex-post regulatory measures to remedy the downsides of these monopolistic tendencies. .

Aligned hydrogen quality: The lack of an aligned cross-border approach with regard to hydrogen quality specifications would raise the risk of cross-border flow restrictions and market segmentation.

6.1.4 Impacts of option 1: Rights for network operation tendered

An in-depth assessment **of Option 1** was not performed.

Like in the BAU-scenario, this option entails a ‘competition for the market’ model. It differs from BAU in several aspects e.g. it can be expected that some of the monopoly rents of unregulated networks would accrue to the Member State through tendering revenues. However, monopolistic conduct will still negatively affect network users and tender revenues mainly represent a distributional effect. Relative to BAU, the building of parallel networks would be avoided and, depending on tender designs adopted at national level, it may be somewhat more conducive in comparison to BAU to (cross-border) market integration provided that a level of coordination between Member States takes place. Moreover, creating appropriate repurposing investments is challenging in a tendering approach as private parties and TSOs (which may be allowed to participate) would not participate in such a tender on equal terms[112]. However, these differences still means that the impacts of Option 1 are unlikely to be materially different from BAU. It is thus highly unlikely that Option 1 would be retained as a preferred option (as opposed to Option 2 and 3) once BAU is rejected as the preferred option whereas the benefits of BAU could also be analysed in comparison with Options 2 and 3.

6.1.5 Impacts of option 2.a: Main regulatory principles only

6.1.5.1 Economic impacts

(Cross-border) market integration: As negotiated TPA implies the absence of tariff regulation, divergent (national) TPA-regimes can accordingly develop which may impede the development of interconnections between EU member states and thereby cross-border trade. A limited degree of cross-border market integration affects the ability of operators in certain Member States to have access to large scale storage and imports. Whilst defining LCFs and having a light GO system in place addresses to a certain extent cross-border issues, this solution may lead to a duplication of regulatory structures and incoherencies and would put RES based hydrogen and fuels at a disadvantage compared to LCH and LCF.

Investment incentives (new and repurposed infrastructure): The limitation of full commercial flexibility following the introduction of regulation under this option might hamper investments, but the introduction of negotiated TPA provides ample room for network operators to enter into long-term transport agreements to finance (initial) network investments. The option to operate gas and hydrogen networks in a joint asset base (common RAB allowed/no horizontal unbundling) is likely to facilitate repurposing as network operators have the option to finance and de-risk networks across users of both natural gas and hydrogen infrastructure. This could be relevant during the hydrogen market ramp-up phase over the coming decade, where utilisation of hydrogen pipelines is likely to be low relative to capacity, and hydrogen network tariffs can be expected to be high otherwise. A common RAB approach will enable operators to spread these costs to the larger group of network users thereby enable them to offer more attractive tariffs to early hydrogen network users neutralising investment risks. The option of a common RAB does however entail the risk of overinvestments in repurposing pipelines, also because it does not address the externality/risk that gas-TSOs will finance the domestic hydrogen network with revenues collected from natural gas network users in other Member States through cross-border tariffs. The lack of any regulation on import terminals means that investments incentives are not affected by EU rules. Storage operators would lose some of their commercial freedom, but remain relatively free to choose their contract partners and structure investments.

Market structure: The introduction of vertical unbundling in combination with the requirement of TPA ensures that network operators do not have the incentive to discriminate against users of their network, and it enables access of all parties to hydrogen networks (no market foreclosure). This enables the emerging hydrogen market to become a competitive market that is characterised by a higher uptake of (renewable) hydrogen and lower prices than in the absence of regulation. A joint RAB and absence of horizontal unbundling could distort the level playing field between incumbent gas network operators that want to repurpose their assets for hydrogen transport and other (private) parties that have an interest in investing in and operating hydrogen networks. The latter group does not have the option to finance the development of pipeline infrastructure from (regulated) revenues obtained from the operation of natural gas networks. With a joint RAB, hydrogen and natural gas network tariffs would no longer be cost reflective as natural gas users could end up financing the

[112] See also Guidehouse (2021) page 44.

hydrogen network. Accordingly, a distributional effect of hydrogen network costs is expected under the absence of horizontal unbundling as hydrogen and gas consumer groups may differ substantially in an early phase. (Initially hydrogen is expected to be largely used by industrial consumers while natural gas consumers also include smaller (e.g. household) consumers. Whist such risk may be low, in view of the potential competition from other forms if imports, potential market power by terminal owners is not contained in any way. Negotiated access to large scale storage would ensure a minimum degree of non-discriminatory third-party use of hydrogen-ready underground storage but is more prone to abuse, especially when commercially important and rare especially at early stages of market development.

Aligned hydrogen quality: The obligation on Member States to agree on cross-border hydrogen quality aspects would limit the risk of cross-border disputes and market segmentation. However, the lack of a harmonised EU approach still represents a risk to cross-border flows and to hydrogen end-users, which can be only partially remedied by establishing a cross-border dispute settlement tool. At the same time this options leaves flexibility to the Member States on hydrogen quality standards in the domestic network without interference with national specificities of hydrogen production and qualities.

6.1.6 Impacts of option 2.b: Main regulatory principles with a vision

6.1.6.1 Economic impacts

Market integration: The introduction of strengthened regulation under this option is expected to further facilitate cross-border integration. Regulated TPA and tariff regulation means policymakers and NRAs to require certain forms of top-down cross-border coordination and creates more uniform market conditions. The introduction of regulated TPA at EU level ensures non-discriminatory access to cross-border infrastructure (including for interconnections with third countries), whereas transparent and uniform tariffs at EU level ensure better conditions for integrating the hydrogen network. The common terminology and a harmonized certification system for LCH and LCFs will ensure that all related GHG emissions are correctly accounted for in a life cycle analyses approach and enable Member States and economic operators alike to effectively compare their carbon footprint solutions. This will foster cross-border trade in LCH and LCFs. Such communality of main principles avoids regulatory divergence and barriers.

Investment incentives (new and repurposed infrastructure): The combination of regulated TPA and tariff regulation under this option is expected to reduce revenue risks which may facilitate investments once a secure and vast customer base for the hydrogen transport network has developed. Restricting commercial leeway with the introduction of regulated TPA and tariff regulation may render initial investments in the hydrogen network less attractive. This effect will however be eased by allowing negotiated TPA in the market-ramp up phase towards 2030 under this option. Temporarily allowing the cross-subsidisation of hydrogen networks via revenues obtained with gas network activities is expected to accommodate investments in repurposing pipelines for hydrogen transport whilst the externality that these are financed by natural gas network users in other Member States is addressed. (This risk of overinvestments is also contained by the requirement for a market test, a measure developed under Problem Area 3). The grandfathering of existing rights and permits of methane infrastructure when used as hydrogen infrastructure as well as guidance in this regard for new build pipelines will take away a potential barrier for investments in hydrogen infrastructure and improve investment incentives by avoiding regulatory bias between investment projects. The introduction of a regulated access regime for storage is expected to be conducive to investment incentives as both renewable hydrogen producers and consumers are dependent on the intermittent character of renewables to optimise their economic activities. In addition in the ramp-up phase storage is one of the few means available to cover energy security risks. Typical early consumers of hydrogen and natural gas will have equivalent rights assuring that choices between these energy carriers are made on the basis economic considerations as opposed to regulatory arbitrage.

Market structure: Alongside the vertical unbundling requirement, regulated TPA further improves the rights for (potential) third party network users and increases transparency, which facilitates the market entry of upstream (hydrogen producers) or downstream (hydrogen consumers) market parties. This is expected to be beneficial for renewable hydrogen producers that require network connection or suppliers that want to supply consumers with hydrogen. Tariff regulation for transportation and large scale storage sets an upper limit for profits and helps address the adverse impacts of market power in a natural monopoly as firms cannot charge excessive prices. These are to be cost-reflective and set under regulatory control. It will also have the benefit of containing the distortions of the level playing field between gas network operators that want to repurpose their pipelines for hydrogen transport and other parties interested in investing and operating hydrogen networks.

Aligned hydrogen quality: Setting an EU-wide acceptable hydrogen quality (purity) level for cross-border points ensures a harmonised approach across the EU and thereby eliminates the risk of cross-border disputes on hydrogen quality issues and provides clarity to investors, operators and users on acceptable quality. This option also ensures a harmonised approach across the EU on quality management but retains flexibility for Member States to define the acceptable hydrogen quality levels for their domestic networks, i.e. respecting the specificities of domestic hydrogen production technologies.

6.1.7 Impacts of option 3a: Hydrogen rules by Big-Bang

6.1.7.1 Economic impacts

Market integration: Vertically integrated firms that are not unbundled are expected to have fewer incentives to develop integrated (cross border) markets as this could lead to higher competition in the integrated firm's (domestic) market threatening profits in associated upstream and downstream markets Ownership unbundling is expected to target this potential negative effect on market integration[113]. Trade in LCH and LCFs is facilitated like under Option 2b.

Investment incentives: The introduction of the strictest form of vertical unbundling in combination with the requirement of separate RABs and legal horizontal unbundling considerably reduces the commercial freedom to invest in (repurposing) hydrogen pipelines. It entails a stronger disruption of gas TSO operating under an ITO model and vertically integrated private operators. The immediate introduction of regulated TPA and tariffs can secure investments but puts constraints on projects that seeks a more project based finance model in the transition phase. An EU system of permitting and land-use rights for hydrogen pipelines may provide a better level playing field for investments (but will come at high costs). Like under Option 2b, a regulated access regime for storage is expected to be conducive to investment incentives by hydrogen producers and consumers.

Market structure: The introduction of regulated TPA with the strictest form of vertical unbundling creates optimal conditions for a competitive market with non-discriminative market entry. The separation of RABs combined with the requirement of stronger horizontal unbundling prevents that network operators that pursue both hydrogen and gas network activities can redistribute the (high) costs for initial hydrogen network users to remaining users of the natural gas grid. Like under Option 2b, a proportional response exists to the potential threat of market power by large scale storage operators and import terminals.

Aligned hydrogen quality: The same impacts are expected as under option 2b as the same approach is taken under option 3a for hydrogen quality.

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[113] *The Impact Assessment on Gas* (European Commission, 2007) showed that fully unbundled TSOs reinvest a higher share of their congestion revenue in new capacity. According to the EC, this is because "vertically integrated companies have an interest to protect their supply business in their home market by limiting cross-border capacity" (European Commission, 2007, S. 34). Ownership unbundling increases incentives for network operators to integrate markets by removing.

6.1.8 *Impacts of option 3.b: Hydrogen rules by Big Bang plus*

6.1.8.1 Economic impacts:

As option 3b builds further upon option 3a, the economic impacts of option 3b are expected to be similar to the economic impacts of option 3a. However, as it provides an alternative to ownership unbundling (as under Option 3a) for currently vertically integrated network operators, it have lower implementation costs and is less disruptive. Moreover, the creation of an EU TSO tasked with operating and developing an EU hydrogen network under this option is expected to profoundly accommodate **cross-border market integration** as it internalises the coordination of the development of the (regulated) cross-border hydrogen network within the EU. It also has synergies with other main regulatory principles, for instance, it can facilitate setting up the ITC mechanism (that may be required in view of the prospect of avoiding cross-border tariffs) and network planning.

6.1.9 *Who would be affected and how*

Whilst regulatory burden and administrative costs vary between options, they are expected to be easily outweighed by the economic benefits under all options[114]. The concrete effects on specific parties is further described in Annex 3

Table 5. Who is affected and how by the options in problem area I (in terms of administrative and economic costs) 0 = neutral, -= negative effect on costs +=positive effect on costs

Problem Area I	**BAU**	**Option 1**	**Option 2**		**Option 3**	
			Option 2a	*Option 2b*	*Option 3*	*Option 3b*
Hydrogen producers	0	-	**-**	-	**--**	**--**
Hydrogen consumers	0	-	**+**	++	**++**	**++**
ACER	0	0	**-**	**--**	--	**--**
NRAs	0	-	**-**	--	--	**--**
Public administrations/MSs	0	-	**-**	-	**--**	**--**
Natural gas TSOs pursuing hydrogen transport activities	0	0	**-**	**--**	--	**--**
Private hydrogen network operators	0	-	**-**	**--**	**--**	**--**
Terminal operators	0	0	0	**-**	-	-
Large scale storage operators	0	0	-	**--**	--	--

6.1.10 *Environmental impacts of options related to Problem area I*

A lower level of regulation and accordingly cross-border integration (as assumed under the BAU-scenario and option 2a) is expected to have negative effects on the cost-efficient uptake of (large volumes) of renewable hydrogen as it will become more difficult to connect favourable renewable hydrogen production locations with distant demand centres. Due to the market structure that might

[114] See also *assistance report to the impact assessment for designing a regulatory framework for hydrogen*, page 7 (Guidehouse, 2021)

develop, higher entry barriers are expected for new and mostly renewable hydrogen producers vis-à-vis current fossil based hydrogen producers. A higher level of regulation is expected to be beneficial for renewable hydrogen producers that ask for network connections or suppliers that want to supply (distant) consumers with (cross-border) produced renewable hydrogen. Fostering access to large scale storage, allowing renewable hydrogen producers to balance intermittent production with stable off-take requirements will equally foster renewable hydrogen production.

6.1.11 Summary of modelling results for Problem area I (quantitative assessment)

[Some of the figures in this section are provisional, awaiting updated modelling results]

Four different scenarios are considered for the European hydrogen grid, as shown in the table below.

Table 6: Hydrogen network scenarios for the assessment with the METIS model

Scenario	Minimum cross-border capacity	Maximum cross-border capacity	Optimisation of cross-border capacity	Most likely to happen in regulatory option
Business as usual (BAU)	None	0	No	0 or 1
A constrained	EHB 2030	None	No	2a,2b, 3a,3b (lower end)
A optimised	EHB 2030	None	Yes	2a,2b, 3a,3b (higher end)
B optimised	EHB 2035	None	Yes	Additional drivers

The BAU scenario assumes no cross-border transport of hydrogen via pipelines except for existing commercial pipelines. This reflects the expected situation under regulatory options 0 and 1, where a lack of European regulation could prevent the execution of projects.

Scenarios "A constrained" and "A optimised" assume cross-border capacity based on the updated 2021 European Hydrogen Backbone ('EHB') 2030 vision for dedicated hydrogen infrastructure in Europe[115]. Capacities are fixed in scenario "A constrained" while the METIS model may add additional cross border interconnections in scenario "A optimised". These two scenarios represent the respective lower and higher ends with respect to network investments, if sufficient regulation to allow for cross-border connections is in place, such as in regulatory options 2a, 2b, 3a, and 3b.

Scenario "B optimised" increases the minimum cross-border capacity to the EHB vision for the year 2035. This scenario corresponds to a very high roll-out of cross-border hydrogen networks leading to an oversized hydrogen network with low utilisation rates. Such a scenario is not expected to materialise if driven alone by the regulatory options considered but would require additional drivers.

An additional scenario creates a so called 'sensitivity' to capture the effect of different network tariffs that could result from allowing cross subsidisation under a joint regulatory asset base (RAB) for natural gas and hydrogen networks or from allowing financial flows between separate RABs. "Costs-CAPEX -" assumes lower tariffs for hydrogen transport as a result of cross-subsidisation under a joint RAB (as possible under regulatory option 2a) or financial flows between separate RABS (as possible under regulatory option 2b);

Table 7 shows the main modelling results for the different hydrogen grid scenarios assessed. For the four different scenarios, it shows the GW of interconnection capacity (both repurposed and new) between EU Member States as well two measures for the costs of hydrogen: **costs of delivery** capturing costs incurred in the hydrogen value chain and **the total costs** which include additional costs outside of the hydrogen value chain as identified by the METIS model.

[115] Guidehouse (2021). Extending the European Hydrogen Backbone: a European hydrogen infrastructure vision covering 21 countries. Utrecht: Guidehouse.

[The costs of delivery presented in Table 7 do not (yet) include the costs of electricity procured on the market].

Table 7: Main hydrogen modelling results

Scenario	Inter-connection repurposed methane [GW]	Inter-connection new hydrogen [GW]	Inter-connected region	hydrogen storage capacity [TWh]	hydrogen costs of delivery [EUR / kg]		hydrogen total costs [EUR / kg]
					average	range	
BAU			none	20,8	2,3	4,2	3,1
A-constrained	19	10	BE-DE-FR-NL	18,3	2,1	4,1	2,9
A-optimised	44	27	EU	17,9	1,7	2,3	2,5
B-optimised	54	130	EU	17,7	1,8	2,7	2,6
Costs CAPEX	46	30	EU	17,5	1,7	2,4	2,4

The assessment confirms the economic advantage of encouraging a European hydrogen network. A rightly sized cross border interconnection capacity can reduce the costs of hydrogen as well as the price differences between Member States.

Moving from the BAU scenario to a scenario with a limited exchange capacity of 29 GW between 4 MS (scenario "A-constrained") reduces the average total costs of hydrogen by 6%. Yet, the range between the most and the least expensive hydrogen supply across Member States changes only very little from 4,2 to 4,1 EUR/kg) as most EU MS are still disconnected from the EU hydrogen transport infrastructure. If the regulatory frameworks are sufficiently aligned to allow cross border trade across the European Union, 71 GW of interconnections (44 GW of which repurposed) are built, creating an integrated EU hydrogen network and market. This further lowers the average costs of hydrogen delivery to 1,7 EUR/kg and reduces the difference between the highest and lowest costs to 2,3 EUR/kg. If however, the expansion of cross border connections is further increased as in the "B optimised" scenario, the costs of hydrogen slightly increase due to the additional network costs.

The EU-wide production of hydrogen is further optimised if grid fees can be reduced, as e.g. in the case of a common RAB for methane and repurposed hydrogen pipelines or separate RABs with financial flows allowed. In the "Costs CAPEX- "- sensitivity, a reduction of grid costs by 50% would lead to 5 GW of additional interconnections. Yet, it would not significantly lower costs for hydrogen. It needs to be noted that the sensitivity only shows the possible direction to which the energy system may react to grid fees. Given the particular techno-economic situation for gas-assets (age, RAB methodology applied, utilisation) the exact effect would need to be determined for each pipeline.

6.2 Assessment of options for Problem area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

6.2.1 Methodological approach

The analysis of options builds upon the more detailed analysis of policy measures, presented in Section 5. The focus is set on the year 2030. In the modelling of the results, different approaches were applied, depending on data availability and appropriateness. They range from dedicated, scenario-based modelling exercises with the EU energy system model METIS, over semi-quantitative estimations to qualitative analyses. The analysis relies on quantitative framework data from the MIX-H2 scenario. A more detailed description of the methodology is available in Annex 4, Analytical methods.

Any increase in biomethane production brings an increase in overall system costs, as long as production costs for biomethane remain high and CO2 prices relatively low. However, the enhanced utilisation of biomethane provides secondary benefits, such as improved energy security and reduced energy imports. Moreover supplying renewable gases on the basis of a market framework allows to exploit the production costs differences and hereby lower the amount of necessary public support.

6.2.2 Impacts of option 0: BAU – No intervention

6.2.2.1 Economic impacts

In the baseline scenario, biomethane would develop on average below recent growth rates, as increased biomethane development may be restricted in some Member States by non-existing or inadequate regulation or technical specifications. Biomethane production could amount to a rough estimation of around 44 TWh, or around 2-3% of gross gas supply in 2030. In the baseline, the injection of synthetic methane would not be significant in 2030.

The reliance on national and voluntary initiatives to address barriers in the LNG sector would have more moderate effects on terminal utilisation, tariffs and total LNG inflows.

The current SoS Regulation would apply focusing on natural gas. The resulting poor management of possible disruptions could erode the public support in the transition. The economic impact of doing nothing cannot be quantified.

6.2.2.2 Environmental impacts

Compared to the MIX-H2 scenario, natural gas consumption could in the baseline increase slightly to compensate for the reduced biomethane production. If natural gas does fill in the biomethane production gap, this would lead to a slight increase in total greenhouse gas emissions of the EU energy system.

6.2.3 Impacts of option 1: Allow renewable and low carbon gases full market access

6.2.3.1 Economic impacts

Option 1 allows for **integration of the biomethane potential** at lower costs than baseline. The **access of locally produced renewable and low-carbon gases to the VTP** would grant producers a price for biomethane 1 €/MWh (5%) higher than under the bilateral agreements. In this case public support schemes could be reduced by some 10M€ annually in the Member States where the access to VTP is not yet implemented[116]. The costs of reverse flows depend on the size of the compressors and costs of deodorisation. In general terms these costs add to about 1.9 €/MWh[117]. A sensitivity analysis, assuming that 10% of biomethane plants would be facing oversupply, shows that reverse flow investments would allow to additionally integrate 2.2 TWh of biomethane in the EU per year, corresponding to 4.4% of the 50 TWh/year total biomethane production in the EU projected for 2030[118].

The **framework of strengthened cross-border coordination on gas quality** and the obligation on Member State to set and publish the national allowed levels of hydrogen blends[119] may lead to a large-scale introduction of hydrogen blending at the TSO level. Based on the national plans and national thresholds for maximum acceptable hydrogen blends announced by several Member States, blending clusters in Europe are expected to emerge:

- a Western-European (with 10% as the joint blending threshold, i.e. aligned with the highest blending threshold in the cluster)[120];

[116] Artelys (2021)
[117] This corresponds to 70 M€ of investment costs and 3 M€/year of operational costs.
[118] The results of this sensitivity analysis are highly dependent on a set of parameters, Artelys (2021).
[119] More details are included in Annex 7 on Gas quality: Hydrogen blending cross-border framework.
[120] Composed of Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Portugal, Spain and Switzerland.

- an Eastern-European (with 1,9% blending threshold, i.e. aligned with the highest blending threshold in the cluster); and
- a third UK-Ireland cluster (at 1,1%, the UK's national blending threshold).

This scenario would result in up to 50 TWh/year of hydrogen injected in the transmission network[121], at an adaptation cost of the gas system of up to 4 B€/year.

For **energy security** this option would result in slightly enhanced quality and reduced costs for identifying and implementing the appropriate measures due to reusability of existing good practices. However, the impact of non-binding guidance could be qualified as marginal, because of lack of assurance. The resulting cross-border asymmetry would be sub-optimal in particular as regards the bilateral solidarity and cybersecurity.

Option 1 ensures compliance with the 55% GHG emission reduction target, closing the potential gap that may occur under the Baseline. Not having these option in place might put at risk the target achievement, i.e. falling short of the 50 TWh renewable gas by up to 10%. This would imply additional emissions of about 1 Mt CO2 annually.

The injection of hydrogen would decrease the CO2 emissions of the gas system, saving up to 7 MtCO2/year (at significant abatement costs).

6.2.4 Impacts of option 2: Promote market access and security of renewable and low carbon gases

6.2.4.1 Economic impacts

Compared to Option 1, under Option 2, the integration of biomethane production may be realised at lower total costs, whereas biomethane volumes are expected to remain unaltered. Assuming a 1%-point decrease in WACC, this option would bring cost savings of 2% or about 10 M€/year in the countries without connection obligation granting public support. **Connection cost allocation** in favour of the biomethane producer might be a more relevant lever, significantly reducing the burden on the producer but increasing the burden on the gas consumers that are likely to face higher gas tariffs.

Reduced injection tariffs for renewable and low-carbon gases are expected to have no major effect as these tariffs are marginal compared to the overall LCOE (<1%). Under support schemes, removal/reduction of injection tariffs would merely represent a reallocation of costs from gas consumers to tax payers. In the absence of a support scheme, the removal of injection tariffs would enhance competitiveness, yet to a marginal extent (<1€/MWh compared to an overall LCOE of 88 €/MWh on average).

The impact of an **EU-harmonised allowed cap for hydrogen blends** will strongly depend on the actual blending level chosen. Below a value of 10% the allowed cap will impact only the Member States in the Eastern cluster, and above a value of 10% it will impact all Member States, giving rise to one unique European cluster. The level of adaptation costs is expected to increase from 3,6 Bn€/year for 5% (with some countries being already at 10%), 5,4 Bn€/year for 10%, 12,5 Bn€/year for 20% and to 37,4 Bn€/year for 30% of blended hydrogen, while the volume of hydrogen injected would follow a proportional increase, from 70 TWh (or 5% volumetric blending level) to 300 TWh (or 30% blending level) per year.

Aligning the rules on **energy security** to the transition of the gas sector is expected to have a high positive economic impact. It would limit the risks for the energy security and cost of possible

[121] This estimate is independent from the MIX-H2 scenario (which does not foresee any blending), but relies on national legislation in terms of blending acceptability and assumes that the required hydrogen quantities would be available.

disruptions [and save time and resources]. Effective cross-border solidarity would reduce the cost of national security measures. A harmonised approach on cybersecurity in gas would strengthen security specific requirements for the gas companies, unifying risk management approaches in the domain of digitalisation of gas infrastructure and providing an adapted list of key security measures.

6.2.4.2 Environmental impacts

This option ensures the effective integration of biomethane to meet the 55% GHG emission reduction target. The connection obligation with firm capacity for biomethane could reduce GHG emissions marginally, by 0.1 Mt CO2 if exceeding the biomethane production volume assumed under Option 1. Higher transparency and better access regime to LNG terminals may have a positive impact on share of renewable and low carbon gases imported in the EU replacing natural gas imports and reducing emissions at the same time.

The impact of hydrogen blending at the TSO level would depend on the actual allowed cap. The avoided CO2 emissions could range from 8 MtCO2/year (for a 5% allowed cap, with some countries being already at 10%) to 33 MtCO2/year (for a 30% allowed cap). However as equipment must be adapted for higher blending thresholds, the associated GHG abatement costs would also increase from 433 €/tCO2 (5%, with some countries being already at 10%), 509 €/tCO2 (10%), 568 €/tCO2 (20%) and to 1114 €/tCO2 (30%).

6.2.5 Impacts of option 3: Allow and promote renewable and low carbon full market access, and security, and tackle issue of long term supply natural gas contracts

6.2.5.1 Economic impacts

Limiting the duration of new long-term supply contracts as of 2050 would tend to increase the market price of natural gas. However, by 2030, and possibly also by 2040 this effect is expected to be marginal as major shares of gas supply are already covered via the existing LTCs and under this option such contracts will be possible unless the duration exceeds the date 2050. Similar effects are expected from **removing derogations from Article 32** for take-or-pay contracts for natural gas.

The impacts of addressing **pancaking for renewable and low carbon gases only** will reduce overall costs of renewable and low carbon gases when transporting them across the border. More importantly such measure will increase gas-to-gas competition for renewable and low carbon gases. This means that the cheapest producers will be able to sell gas all across EU. In this way the differences of costs of production of biomethane between Member States can be exploited reducing overall costs biomethane and the need for state aid to the level of the production costs of the cheapest producer. This measure is therefore a chance to increase competition, liquidity and trade for renewable gases to the benefit of the end-consumers. Moreover, transparency and benchmarking of costs of the TSOs may help to peer review the level of tariffs applicable at cross-border points.

A priori, the **market tests for accepting of renewable and low carbon gases** at the LNG terminals and storages would not result in a significant import of biomethane per se as it is too expensive[122] in comparison to standard natural gas in 2030, unless the price for guarantees of origin or the carbon price reach high values (15 €/MWh HHV or 80 €/tCO2). Market test will, however, increase transparency between producer and consumers.

6.2.5.2 Environmental impacts

In 2030, no additional environmental impacts are expected for this option compared to Option 2. Limiting the duration of natural gas LTCs might create additional room for renewable and low-carbon

[122] Low-cost biomethane potentials exist outside the EU which are competitive with natural gas. However, it is considered rather unlikely that these potentials would be exported to the EU instead of being used locally.

gases. However, as long as renewable and low-carbon gases are not economically competitive, the gap still is likely to be filled by short-term natural gas contracts. Abolishing cross-border tariffs for renewable gases may narrow this gap.

6.2.6 Impacts of option 4: Allow and promote full renewable and low carbon market access, and security, tackle issue of long term supply natural gas contracts, remove border tariffs and set EU gas quality standards

6.2.6.1 Economic impacts

Limiting duration of the long-term contracts already as of 2030 would strengthen the impacts of option 3. However, it would not fundamentally change their nature.

The **elimination of intra-EU cross-border tariffs** for all gases will have a significant impact on the European gas market. The wholesale gas prices are likely to increase slightly in the transit countries and to decrease in the peripheral countries. These changes of gas wholesale prices and internal exit tariffs may trigger a shift in the merit order between gas fuelled power plants (notably open cycle gas turbines) and coal power plants in both directions (coal to gas or gas to coal) for a few EU Member States.

The impact on welfare between the different gas stakeholders (consumers, producers, TSOs etc.) depends on the parameters of the measure. It seems to benefitEU gas consumers of up to about 500 M€/year. Variants where the third country entry tariffs were increased or where entry tariffs were applied to LNG terminals have shown to reduce this gain, even shifting it to a negative impact on the EU consumers if entry tariffs are too high. The above impacts were analysed in case Nord Stream 2 is put into operation and the other import pipelines remain in place. The contemplated abolishment of intra-EU tariffs would benefit the Member States in South -Eastern Europe and Baltic States. The above impacts could be readjusted by the means of an inter-compensation mechanism among the TSOs. As sensitivity, a scenario without Nord Stream 2 was conducted, showing an overall wholesale market price level increase.

The impacts of **biomethane setting the gas standard** depends on which gas type under which framework conditions becomes the complementary gas within a gas grid section. If the share of biomethane outweighs natural gas in a gas grid section and the conditioning of biomethane would be more expensive than the adaptation of natural gas to the quality properties of biomethane, then the regulatory framework should allow biomethane to become the determining gas type. From an overall systemic point of view, however, this would only make sense if the (financial) efforts for adapting the quality of biomethane to natural gas were greater than adapting natural gas to biomethane.[123]

As high **hydrogen blending levels** are unlikely to be implemented at the TSO level on a voluntary basis, the adoption of a maximum blending cap is expected to play a role only in the case where both the maximum and minimum allowed caps are set at 5%, above which adaptation costs become very high. In this particular case where all Member States are obliged to accept blends with 5% hydrogen at cross-border interconnection points, the injection of blended hydrogen equals 50 TWh/year in 2030 with adaptation costs reaching around 733 M€/year. An EU-wide maximum allowed cap could ensure the homogenisation of blending rates and prevent isolated initiatives that could lead to unwanted increase of adaptation costs for several neighbouring countries.

[123] As the currently applicable CEN standard is not binding, Member States have already today the possibility to create such a framework. However, the prerequisite must always be that the gas quality requirements of the transported gases do not lead to any damage in the gas grid or for consumers and that consumers can use these gases without disruption.

6.2.6.2 Environmental impacts

The change in gas tariffication is not expected to have a significant environmental impact apart from possible switches in the merit order between coal and gas, which are to be limited would an inter-compensation mechanism between TSO be adopted. Setting both the lower and the higher (maximum) cross-border allowed caps for hydrogen blends at EU-level would lead to a decrease in CO2 emissions, however at increasing abatement cost (depending on the actual blending levels chosen).

6.2.7 Who would be affected and how?

Table 8. Who is affected and how by the options in Problem area II (in terms of administrative and economic costs)

Problem area II	BAU	Option 1	Option 2	Option 3	Option 4
ACER	0	-	N/A	-	-
NRAs	0	+/-	-	-	--
Public administrations/MSs	0	+/-	-	-	-
Consumers	0	+/-	+/-	+/-	+/-
Biomethane Producers	0	+	+	++	++
End grid users	0	0	-	+/-	-
TSOs	0	-	-	-	--
DSOs	0	+	+	+	-
LNG Terminals	0	0	+/-	+/-	-

6.3 Assessment of policy option in relation to Problem area III: Integrated network planning.

6.3.1 Methodology and key assumptions

The assessment of options are based on a qualitative methodology. Analysis of the status quo of NDP preparation (one vs several NDPs) across MSs, are notably based on the ACER report, in order to evaluate the order of magnitude of the expected impact of the option (how many MSs are actually concerned by this option). The analysis also assessed current NDPs regarding their compliance with the elements for all options other than BAU (i.e., involved stakeholders, sustainability criteria, integration of EU climate targets etc.).

Qualitative assessment of costs/efforts related to enhanced coordination between TSOs (e.g., in terms of number of stakeholders that need to coordinate) is based on a review of recent literature[124].

6.3.2 Impacts of option 0: BAU

Keeping the current framework does not resolve insufficient integrated planning and would not lead to more transparency on infrastructure that can be repurposed. This leads to less efficient and non-cost effective planning.

[124] He, Wu, Zhang, & Shahidepour, 2018, IRENA, 2020; ACER, CEER, 2017; CEDEC, EDSO, ENTSO-E, Eurelectric, GEODE, 2016; SINTEF et al., 2020

6.3.3 Impact of Option 1: National Planning

6.3.3.1 Economic impacts

More holistic network planning may ensure a more efficient and cost-effective grid planning that factors in additional framework conditions, which may affect the need for grid infrastructure. Requiring a single, consolidated NDP ensures that potential incoherencies between the visions of different gas TSOs operating in the same country (e.g. in France) are identified, discussed and eliminated, leading to a more coherent, cost-efficient network planning procedure, lowering the risks of over-dimensioning the system or stranded assets.

The transparent involvement and management of all relevant stakeholders may allow to anticipate new trends (e.g., with respect to the deployment of synthetic methane production, the use of ammonia, etc.), enhance the anticipation of the evolution of gas production and demand (e.g. level of energy efficiency efforts, flexibility of the demand), thereby bringing the planning closer to reality and enabling appropriate investment decisions. It may further raise the acceptability for gas infrastructure projects, thereby minimising the risk of opposition and lawsuits and related costs.

Joint planning of pipelines, storage and LNG may reduce investment needs, as all these assets provide flexibility but are owned and operated by different stakeholders. A coherent approach saves infrastructure costs that are typically socialised via grid tariffs.

The main benefit of reporting on decommissioning of methane pipelines is that it enables more efficient investment decisions, notably with respect to the repurposing of gas pipelines for hydrogen instead of constructing new ones (which features CAPEX savings of 70 to 90%[125]) and the exploitation of cross sectoral synergies.

6.3.4 Impacts of Option 2: National Planning based on European Scenarios

6.3.4.1 Economic impacts

Building joint electricity and gas scenarios would ensure that indirect interlinkages are treated in a consistent way in subsequent processes by gas and electricity TSOs. This ensures that the planning exercises are carried out using a common vision of the future, thereby eliminating risks that electricity and gas TSOs plan the evolution of their systems based on incompatible assumptions (e.g. electricity TSOs assuming a strong deployment of heat pumps in the residential sector while gas TSO assume a deployment of gas boilers). The participation of DSOs, LSOs and SSOs in scenario building activities would ensure a common vision of the different stakeholders implying that investment decisions (which are still taken independently) are more aligned, avoiding conflicting or redundant investments, thereby savings in societal costs. The implementation would entail moderate cost, as joint scenario building does not require to establish a common simulation model, but rather to coordinate on a set of core assumptions.

The economic benefits of the introduction of sanity checks emerge from the higher level of consistency between the gas and electricity NDPs, notably in terms of the identification of best suited areas for electrolysers, leading to consistent interventions on electricity, methane (e.g. via repurposing) and hydrogen networks at the local level.

Integrating one scenario in line with EU climate targets ensures that the network planning takes into account the decarbonisation strategies at the national and EU levels, reducing the risk of potential lock-ins or stranded assets. Linking the NDP scenario framework to NECPs and LTS would increase the coherence of energy system planning – both across sectors and across Member States.

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[125] CAPEX data based on (Guidehouse, 2021)

6.3.5 *Impacts of Option 3: European Planning*

6.3.5.1 Economic impacts

There are important benefits to jointly plan the evolution of the location of electrolysers, electricity, methane and hydrogen grids. Given the long lifetime of infrastructure assets (typically around 50 years), the transition of infrastructure use from natural gas to other renewable and low-carbon gases needs to be planned as early as possible in order to take comprehensive and robust investment decisions that imply minimal costs for society. Furthermore, a joint planning ensures that the efficiency of investments in the gas sector (incl. hydrogen) is compared to alternatives such as electricity networks, and that the most economically, environmentally sound and secure option is identified and selected.

6.3.6 *Who would be affected and how*

Table 9. Who is affected and how by the options in problem area III (in terms of administrative and economic costs)

Problem Area III	BAU	Option 1	Option 2	Option 3:
ACER	0	0	+	--
NRAs	0	-	-	-
Public administrations/MSs	0	N/A	N/A	N/A
Producers	-	+	+	+/-
TSOs	0/-	+/-	+/-	--
DSOs	0/-	+/-	+/-	--
LSOs and SSOs	0	0	+/-	--
Consumers/ Society	-	+	+	+/-

6.3.7 *Environmental impacts of options related to Problem area III*

Implementing sustainability indicators in NDPs under Option 1 could contribute to selecting future-proof projects only. If implemented in a rather light form as informative indicator it could contribute to market transparency. If implemented as a mandatory criterion, a sustainability indicator could be used to help select (societally) beneficial projects that otherwise might not be realised.

More integrated power, gas and hydrogen network planning paves the way for a deep integration of renewable and low-carbon gases with the electricity system, and is thus expected to feature significant emission reductions.

Finally, by reducing the risk of over-investments by ensuring investments are based on a common vision of the future, all options have a positive environmental impact by reducing the footprint of the overall energy system. Reporting on decommissioning has positive environmental impacts as it can lead to a better identification of repurposing potentials, and thereby avoid building a new infrastructure, resulting in a lower environmental footprint of the infrastructure, including the use of raw materials required for building the asset.

6.4 Assessment of policy option in relation to Problem area IV: Lack of customer engagement and protection in the green gas retail market

6.4.1 Methodological approach

In a context where gas continues to be a major, even if declining, element in household energy consumption, this section assesses the policy options on the modelling used for the whole impact assessment as well as on the basis of qualitative methodology in relation to the barriers to customer engagement in the gas market as part of the energy transition and effective customer protection. When available, quantitative information has been used, while where economic impacts cannot be quantified, desktop research and case studies are used to inform estimates of the extent of possible impacts, as well as possible winners and losers.

6.4.2 Impacts of option 0: Baseline scenario, No action (BAU), beyond usual enforcement measures

Option 0 represents the baseline scenario, as there would be no legislative measures adopted to change to the situation existing today, which would be improved through usual enforcement actions (reinforced administrative cooperation and guidance from the Commission). In this option, the identified issues are not considered as urgent enough to justify a more decisive intervention now in a of decarbonized gas market still at an embryonal stage with its uncertainties. Costs of this non-action would result from not addressing lack of competition and existing high costs for consumers.

6.4.2.1 Economic impacts

This option relies on voluntary measures that risk leaving problems resulting from outdated legislation unaddressed, notably on smart energy management, billing information with termination and exit fees for consumers switching to renewable and low carbon gases. Consistent standards of customer protection seem unlikely to be timely and efficiently achieved by all EU countries. Moreover, this option does not open up the full potential of energy communities in terms of (cost-effective) renewable and low-carbon gas uptake, due to the absence of geographical flexibility and an enabling legal framework to overcome institutional barriers[126] meaning such energy communities will remain unequally spread across the Member States and not focus on renewable and low carbon gases.[127]

6.4.3 Impacts of option 1): Non-regulatory approach: enforcement also through soft legislation and dialogue with the Member States

6.4.3.1 Economic impacts

In addition to the benefits from enhanced enforcement, a non-legislative approach to harmonising price regulation based on Commission Guidance could facilitate the removal of barriers to competition and innovative renewable gas products. However, continued market uncertainty in this regard would be a barrier to rolling out new products.

Some indirect improvements to the health and well-being of energy poor consumers from the exchange of good practices stemming from the activities of the EU Hub for Energy Poverty may be gained. In the absence of new, ambitious legislative measures, smart metering deployment remains geographically limited. Nevertheless, this option is efficient to a certain extent as it mandates the transfer in a single act of all relevant smart metering provisions.

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[126] On the importance of an enabling legal framework for the development of energy communities, see JRC report ‘energy communities: an overview of energy and social innovation’, p. 32 and Frontier study (2021), ‘Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer’, p. 9.

[127] A vast majority of all energy cooperatives are located in NL, AT, DE, DK. See JRC report ‘energy communities: an overview of energy and social innovation’, p. 5.

6.4.4 *Impacts of option 2: Flexible legislation addressing all problem drivers*

6.4.4.1 Economic impacts

Improved retail competition should result from the phase-out of blanket **price regulation** for large, medium-sized and small enterprises in six Member States.[128] **Switching** to a more competitive offer has a significant savings potential, varying per Member State, with the highest potential in Germany where households could save up to EUR 694 annually.[129]

Non-discriminatory **access to consumer data** and nationally harmonised arrangements, mirroring those for electricity, as well as measures facilitating interoperability within the EU will help new suppliers and service providers to enter the market, develop innovative products, resulting in increased competition, consumer engagement and economic benefits. Moreover, such interoperability rules for access to data will foster the creation of the energy data space[130] and will facilitate data sharing across the EU. **Smart metering** supporting the flow of such data could reinforce these trends. DSOs will be in a position to lighten, and improve, administrative processes and offer increased customer services. Moreover, smart meters can be made available at consumers' request and expense, when there is no systematic deployment. However, direct consumer benefits (i.e. no systemic impact) are generally found to be lower than direct costs of €100-350 (on average, benefits close to €225).[131] Member States will face an additional administrative impact for re-evaluating their national smart metering deployment case.

Mirroring the framework for citizen energy communities of the Electricity Directive into the Gas Directive[132] would enable consumers to buy renewable and low-carbon gases irrespective of their geographical location, as well as bring benefits for the local economy,[133] increase public acceptance of renewable gas projects and help mobilise private capital investments[134] in renewable and low-carbon gases.[135]

Furthermore, better measurement of the number of households on energy poverty will allow more EU and national targeted policies. A generic definition of energy poverty in the legislation will clarify its concept, improving the functioning of the current provision and further helping knowledge dissemination and synergies across EU policies in energy efficiency and consumer protection.

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[128] Deregulated prices will help consumers benefit from better choice and services in a context of better functioning retail competition. As indicated in figure 20 of Annex 9, more liberalised markets tend to have a higher average number of offers, percentage of green offers and average switching rates. See also 2019 ACER market monitoring report, p. 50.

[129] Quarterly report on European Gas Markets with focus on the European barriers in retail gas markets, Market Observatory for DG ENERGY, Volume 13, issue 4, fourth quarter of 2020. See also figure 22 of Annex 9.

[130] European Data Strategy COM/2020/66 final; Data Governance COM/2020/767 final

[131] Frontier study (2021), quoting data from recent gas smart metering deployments. Also Tractebel report on benchmarking smart metering deployment in the EU-28 (2019).

[132] On the importance of an enabling legal framework for the development of energy communities, see JRC report, 'energy communities: an overview of energy and social innovation', p. 32. See also Frontier (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 9 which shows that – potentially due to the framework for REC and CEC – in 2019 the amount of energy communities has increased.

[133] Hannoset et al. (2019), 'Energy communities in the EU', p. 41.

[134] The potential of Energy Citizens in the European Union, CE Delft, 2016: "83% of the EU's households could potentially become an energy citizen and contribute to renewable energy production"

[135] Artelys study (2021).

6.4.5 *Impacts of option 3: EU Harmonization and extensive safeguards for customers addressing all problem drivers*

6.4.5.1 Economic impacts

Overall this option has the potential for significant economic gains from much more integrated retail gas markets across the EU, with clear and consistent rules and standards of protection – in particular with lower costs for renewable and low carbon gases.

Phasing-out blanket **price regulation** in the household gas markets of 15 Member States would lead to significantly increased market opening and effective retail market competition.[136] The additional set of support measures for energy communities would amplify their contribution to the deployment of renewable and low-carbon gases.[137] However, this benefit may be offset by one-off costs and ongoing labour and operational costs to implement the supporting framework[138].

This would be complemented by a single EU **data management** model for all, easier to enforce at EU level, helpful for new market entrants, and equally beneficial for alternative suppliers, consumers and community energy. However, it would have very high implementation costs. Similarly, mandating a rollout for **smart meters** throughout the EU, irrespectively of the outcome of the national cost-benefit analyses, is not a cost-effective operation[139] as it ignores the national context.

6.4.6 *Who would be affected and how*

Table 10. Who is affected and how by options in problem area IV (in terms of administrative and economic costs)

Problem Area IV	**Option 0**	**Option 1**	**Option 2**	**Option 3**
NRAs	-	-	--	--
Public administrations/MSs	-	-	-	-
Consumers	+/-	+	++	++/-
DSOs	-	-	+/-	-
Suppliers	+/-	+/-	++/-	+/--
New entrants (innovative services)	-	-	+	+

6.4.7 *Environmental impacts of options related to Problem area IV*

The legislative options examined above – Option 1 (Flexible legislation) and Option 2 (Harmonization and extensive safeguards) – are each expected to have significant, albeit indirect, environmental benefits from higher levels of renewable gas penetration. The measures will benefit citizens and communities in particular, which the analysis has shown represents an important ally in increasing social acceptance, mobilising private capital and thus facilitating the deployment of renewable and low-carbon gases. The strengthening of rights fosters sustainable choices, both by providing consumers a clear overview and control of their consumption, as well as awareness about the origin of their energy. Option 2 appears to be most effective for this purpose. Phasing out blanket

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[136] ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 47.

[137] Artelys study (2021);Amecke, H., 'German Landscape of Climate Finance, Climate Policy Initiative' (2012) Climate Policy Initiative 2016, p. 4; and GRDF, 'Méthanisation Agricole Retour d'expérience sur l'appropriation locale des sites en injection', 2016.

[138]Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', pp. 15-17.

[139] Tractebel report "Benchmarking smart metering in EU-28" (2019).

price regulation – particularly in Member States with very low margins – will help address the high levels of gas consumption caused by artificially low prices.

6.4.8 Impacts on fundamental rights regarding data protection

Safeguarding EU values and citizens' fundamental rights and security in a developing green, digital energy environment, is of paramount importance. The proposed policy measures on **data management** were developed with this in mind, aiming at ensuring widespread access and use of digital technologies and data-driven services while at the same time guaranteeing a high level of the right to private life and to the protection of personal data, as enshrined in Articles 7 and 8 of the Charter of Fundamental Rights of the EU, and the General Data Protection Regulation.

6.5 Social impacts

The energy transition and decarbonisation policies play a key role in developing Europe's competitive edge as growth and jobs increasingly will have to come from innovative products and services which are closely linked to sustainable and smart solutions. More in specific, the measures assessed in this Impact Assessment are expected to produce several social benefits in each of the problem areas. They would increase the energy security by diversifying gas sources and reducing external energy dependency, for the benefit of the whole society.

6.5.1 Social impacts of the preferred option in Problem Area I

The measures analysed to facilitate the emergence of interoperable hydrogen infrastructure and hydrogen markets (Problem Area I) would foster sustainable growth and jobs *although* the positive impact on employment is difficult to concretely estimate given uncertainties in market development for each option separately. However, the preferred option is the most likely to foster competitive market and pricing, investments and lower costs for hydrogen supplies and hence contributes to economic growth and jobs. Initially, hydrogen is expected to be largely used by industrial consumers whereas natural gas consumers also extent to SMEs and households. Consequently, a distributional effects could occur at an early phase in those Member States where operators of both natural gas and hydrogen networks are allowed to create financial flows between natural gas and hydrogen asset bases. However, under the preferred option these are contained and under regulatory control.

6.5.2 Social impacts of the preferred option in Problem Area II

The possible measures analysed in Problem Area II would allow to integrate renewable and low-carbon gases at lower costs while ensuring energy security. They would increase the potential for cross-border trade and ensure the interoperability of markets, leading to more competition and better possibilities to level out production and demand differences across larger areas; at the same time they would reduce our external energy dependency. The analysed measures increasing biomethane production may lead to a creation of 2000 to 4000 additional local jobs and local added value. The measures can also be expected to have a positive impact on competitiveness and households. This measure would ensure access to all citizens and businesses of renewable and low carbon gases in order to protect energy poor and vulnerable consumers.

6.5.3 Social impacts of the preferred option in Problem Area III

In a similar manner, the analysed measures to ensure transparent and inclusive network planning ('Problem Area III') options are likely to have a positive impact for EU citizens and businesses. Gas consumers would benefit from a more cost-efficient planning as infrastructure costs are typically socialised via tariffs. Better anticipated grid planning avoids stranded assets as much as delayed network expansion and resulting grid bottlenecks (e.g. for new energy carriers such as hydrogen) which comes ultimately at a lower cost for the consumer. These expected savings have to be traded-off against the costs of implementing the preferred measures, which have however been estimated to be small or even slightly negative in the longer term. The net effect would therefore translate into lower prices for energy facilitating overall competitiveness. Lower prices for energy services also have a progressive social impact as energy prices tend to affect households with smaller budgets over-proportionally.

6.5.4 Social impacts of the preferred option in Problem Area IV

Finally, the analysed measures to reduce the low levels of consumer engagement and protection in the decarbonised retail market (Problem Area IV) will wider benefits for the local economies, increase social acceptance of renewable energy projects and help mobilise the private capital investments needed to facilitate the energy transition. Energy communities in rural areas especially have the potential to have positive social impacts by allowing farmers to participate in the development of a green gas economy. Customers will greatly benefit from more and greener offers, better information on sources of energy and as well as their consumption history enabling them to better manage their consumption costs. Decarbonisation will result in low income households bearing a relatively higher burden in terms of heating fuel expenses. Targeted socio-economic measures will thus be needed to minimise such an impact on energy poor and vulnerable consumers.

6.6 Renewable and low carbon gases from third countries.

EU action has significant added-value by ensuring a coherent approach across all Member States as well as towards third countries, since achieving the decarbonisation objectives of the EU may require imports of renewable and low carbon gases from third countries.

The global biomethane export potential is estimated by the IEA at 8084 TWh in 2018, rising to 9731 TWh in 2040. The costs of imports to the EU ranged in 2018 between €12/MWh and €98/MWh. In 2040, import costs are estimated in the range of €13/MWh and €70/MWh (including shipping costs), depending on the region.[140]

The potential for hydrogen imports and exports in terms of volumes and transportation costs is less certain. Under the scenarios used for the present impact assessment they remain limited by 2030, but in 2050 the global market for hydrogen is expected to be between 8,000 and 20,000 TWh[141]. The global 'Power-to-X Atlas' compiled by Fraunhofer IEE comes to the conclusion that, in the long term (by 2050) that the technical potential to produce liquid hydrogen outside Europe is 5x larger than the expected global demand[142].

However, the impacts of measures on third countries depends on the competitiveness of renewable and low carbon gases produced in these countries relative to domestic EU production and the possibilities and costs to import them into EU.

Under the existing regulatory framework, pipelines for natural gas and LNG terminals are already open for imports and are governed by regulatory principles that seek to ensure non-discriminatory treatment that does not depend on geographical origin.

EU hydrogen demand might be partially covered by imports from third countries. One possible means of hydrogen imports are cross-border pipelines connecting the EU with hydrogen-supplying third countries. The regulatory framework is intended to be fully applicable to such import pipelines on the territory of the Union. Due to their cross-border nature, import pipelines would generally be subject to both Union law and the laws of third countries. A regulatory framework for hydrogen could include mechanisms to address the resulting risk of a conflict of laws, such as mandatory agreements to establish operating rules for hydrogen import pipelines.

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[140] IEA (2020)

[141] IEA Net Zero Report (2021) & IRENA World Energy Transition Outlook (2021)

[142] Energy Transition Expertise Centre (ENTEC, 2021), the role of hydrogen import and storage to scale up the deployment of renewable hydrogen.

In addition to hydrogen import pipelines hydrogen can be imported from (more distant) third countries by ships that can use a range of different modes to transport hydrogen, such as in liquid form or as ammonia. These so called 'hydrogen carriers or derivatives' could potentially be reconverted to gaseous hydrogen for subsequent distribution through the EU via a hydrogen network. However, as the optimal import means will also depend on the envisaged end use of hydrogen or derivative[143] it is not yet fully clear what means of hydrogen import will become predominant.

In any event, the competitiveness of imports would equally depend on the availability hydrogen transportation infrastructure to reach demand centres and on functioning commodity markets, which this initiative seeks to promote. Access to import terminals and (subsequent) access to hydrogen networks could be governed by regulatory principles that seek to ensure non-discriminatory treatment that does not depend on geographical origin. The analysed measures for hydrogen do also consider investment incentives for import terminals.

Using a comprehensive certification system for LCH and LCF would allow enforcing a level playing field across all energy decarbonisation options and, by this, ensuring that Member states can effectively compare these. Since such a certification system is global, no discrimination can be expected between economic operators inside or outside the EU.

The conditions that apply to imports in terms of e.g. sustainability are not analysed in this document as they are the subject of other policy initiatives. Measures which promote renewable and low carbon gases may however diminish consumption of natural gas (and fossil based hydrogen). The scope and magnitude of this replacement cannot be predicted at this stage.

The future regulatory regime will need to be inclusive so that partners currently exporting gas to the EU and those who will engage in exporting clean gases in the future have a fair access to the market. The Commission will inform its partners about the legal rules so that the uptake of new commodities and regulating cross-border pipelines happens smoothly. Moreover, the Commission aims in its external policies, in close contact with partner countries, to coordinate Union's decarbonisation policy and energy transitions in those countries.

7 HOW DO THE OPTIONS COMPARE?

7.1 Comparison of options ensuring emergence of cost-effective hydrogen infrastructure and contestable hydrogen markets

The options under Problem Area I compare to each other as follows;

Option 2a: In comparison with the base-line, under which companies are fully unconstrained and 'competition for the market' will continue to predominate, Option 2a, sets the stage for competition 'in the market'. Option 2a entails the introduction of main regulatory principles aimed at countering market power, removing some barriers to cross-border hydrogen trade and fostering market integration, thus improving upon the base-line. It does however not have the same depth and scope of the market design of the mature gas and electricity markets and leaves a large degree of freedom to economic actors. The main regulatory principles are to a certain degree adapted to the specificities of the hydrogen market and seek to remove barriers to reuse existing infrastructure for hydrogen. Option 2a represents a first step with ample flexibility for companies to overcome the early stages of market ramp-up. However, it does not provide further guidance as to where the regulatory framework in which hydrogen markets need to develop will go. Thereby, it does not attempt to avoid the costs associated with ex-post interventions that may be needed at a next step when hydrogen markets have

[143] Hydrogen Insights Hydrogen Council (2021) A perspective on hydrogen investment, market development and cost competitiveness

become more mature. In this sense it may offer economic benefits and efficiencies relative to the base-line, but for the transition only.

Option 2b: In comparison to Option 2a, the main difference is that it defines a clear stepwise approach. Whist avoiding large immediate changes to the way infrastructure operators act today and leaves them ample scope to overcome the early stages of a hydrogen market ramp-up (much like Option 2a), it defines more clearly the regulatory system that will exist once markets have matured. It sets some constraints on the flexibility existing during the transition phase but these aim at avoiding costly ex-post interventions to move to a more mature and deeply integrated, efficient hydrogen market later and in which infrastructure is operated and financed in accordance with economic principles proper to a more mature hydrogen system. It takes into account lessons learnt from the liberalisation of the gas and electricity sectors and exploits the fact that we can take a 'greenfield' approach to regulation, in which choices aimed at creating a competitive market can still be made unconstrained by an entrenched factual or regulatory situation. In this sense, it provides for economic benefits and efficiencies not only for the transition phase, but also sets the stage for efficient hydrogen markets later and avoids the ex-post interventions that would be required under Option 2a and the sunk investment of investors that are affected by them.

Option 3a and b: introduce like Option 2a and 2b 'competition in the market'. Contrary to Option 2a and 2b, it reflects an ambition of setting-up a separate regulatory regime for hydrogen that, whilst adapted to the specificities of the hydrogen value chain and removing barriers, does so without a transition period that seeks to cater for the specific needs of an still immature sector that needs investments for its ramp-up. It prioritises creating regulatory clarity at the cost of the flexibility. By doing so it creates economic benefits and efficiencies by setting a stage for efficient hydrogen markets but at the expense of the conditions that are required for it to transition towards that objective and thus by itself may constitute a barrier for rapid deployment and market development. The EU ISO that is a design feature of Option 3b would foster market integration however, lowers regulatory costs for and can have synergies with other main regulatory measures.

Table 11: Overview of the impacts under problem area I: Hydrogen infrastructure and markets.

Options relative to BAU	Option 2a	Option 2b	Option 3a	Option 3b
Economic impacts	+	+++	+/++	++
Environmental	+	++	+	+
Efficiency	+	++	+	+
Effectiveness				
Driver 1: Market integration	+	++	++	++/+++
Driver 2: infrastructure investments	+	+++	++	++
Driver 3: Non-competitive market structure	+	++	++	++
Driver 4 : Hydrogen quality	+	++	++	++
+,++,+++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

7.2 Comparison of options ensuring access of renewable and low carbon gases to the existing natural gas networks and market

The options under Problem Area II compare to each other as follows:

Option 1: In comparison to the Baseline, Option 1 will provide locally produced renewable gases with access to the hubs and transmission grid through enabling physical reverse flows. This will allow for full integration of the biomethane potential projected under the MIX-H2 scenario, facilitating compliance with the 55% target. It may also help to reduce support scheme costs for locally injected renewable gases and thus the costs on consumers as well as improve their marketing options. However costs of reverse flow investments will be borne by consumers of gas. This option will limit the risk of cross-border flow restriction and market segmentation and implies several European hydrogen blending clusters at the TSO level. The limited nature of intervention under this option will leave flexibility to Member States for setting national allowed blending levels. While the administrative costs remain limited, the gas quality cross-border coordination framework cannot fully eliminate the risk of cross-border disputes. This option will however not ensure effective emergency preparedness during the transition and that the security risks related to the development of renewable and low carbon gases are fully considered by 2030 at the latest. It will not significantly improve the resilience to new cyber threats in the gas sector.

Option 2: In addition to the impacts of Option 1, Option 2 promotes the integration of biomethane which may potentially reduce the costs of production, making state aid less needed. Reducing injection tariff and access tariff is not respecting fully the principle of costs-reflectivity and avoiding cross-subsidisation. Therefore the costs of tariff discounts need to be borne by consumers of gas. This option will bring harmonisation of cross-border blending thresholds across the EU witha pre-defined allowed cap and will reinforce cross-border coordination limiting the risk of flow restriction and market segmentation to a minimum. At the same time it leaves flexibility to Member States on the application of gas quality standards and blending thresholds for the domestic network. Proposed LNG rules will bring improvement of transparency, market access and congestion management resulting in more efficient utilization and potentially additional available capacities for RES&LC gases. This option addresses in an effective and efficient way the handling of energy security risks related to supply of renewable and low carbon gases and the risks related to cybersecurity.

Option 3: Will bring similar results to Option 2 in many aspects especially when it comes to integration of renewable and low-carbon gases, in particular biomethane. However, the abolishment of tariffs will enable more physical cross-border trade with renewable gases based on production costs differentials in the Member States. These benefits may reduce the costs of facilitating injection of biomethane into the grid as identified in option 1 and 2. Moreover measures on allowed revenues will reduce the outliers on cross-border tariffs and the guidance on market mergers will help integrating smaller gas markets and harmonise approach to promotion of renewable gases. For LNG option 3 will bring incentive to prepare for the RES&LC gases imports through mandatory market test mechanism. Removed privileges and limited duration for long-term contracts may lead to a slight increase of wholesale gas price with a long-term effect in terms of organising the energy transition. As in option 2 it will have an effective and efficient impact on the resilience of the new gas system and energy security.

Option 4: Will, in addition to the impacts of Option 3, remove border tariffs for natural and renewable gases in the EU, which will increase overall welfare for consumers and bring more gas-to-gas competition in the market. This will inevitably increase internal exit tariffs in most Member States and possibly the EU-external tariff, and bring overall impact on import gas flows as well as on the European gas market. Option 4 will also reduce the risk of high blending levels taken as a local initiative and ensure EU-level harmonisation of gas quality standards for cross-border interconnection points. For LNG options 4 will mean incentives for renewable gases imports as entry tariffs discounts will be removed for natural gas. With regard to long term contracts, impact of option 3 will be strengthened. As in option 2 it will have an effective and efficient impact on the resilience of the new gas system and energy security.

Table 12: Overview of the impacts under problem area II

Options relative to BAU	Option 1	Option 2	Option 3	Option 4
Economic impacts	+	+	++	++
Environmental	++	++	+++	+++
Efficiency	+/-	+	+	-
Effectiveness				
Driver 1.1: Market/grid access	+	+	+	+
Driver 1.2: Grid connection and injection	0	+	+	+
Driver 1.3: Intra-EU entry/exit tariffs	0	0	+	+
Driver 2: Gas quality rules	-	+/-	+/-	+
Driver 3: Access to LNG terminals	0	+/-	++	+
Driver 4: Long term contracts	0	0	+	++
Driver 5: Ensuring energy security	+/-	+	+	+
+,++,+++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

7.3 Comparison of options ensuring integrated network planning

The options under Problem Area III compare to each other as follows:

Option 1: enhances the current design of NDPs and ensures that all MSs submit a single plan per country or Region, which allows already for a better integration into the TYNDP process providing input from the NDPs to the TYNPD that is built upon the NDPs.

Option 2: facilitates the integration of renewable and low-carbon gases as:

- DSOs are more strongly involved in the NDP process (even though this is already the case in some MSs today), reflecting that production of renewable and low-carbon gases is more likely to be linked to distribution grids in terms of numbers;
- Joint power-gas scenario building facilitates a more concerted approach in network planning, notably with respect to the balance between direct electrification and decarbonised-gas strategies (incl. indirect electrification).

Option 3: The measure would go significantly beyond the joint scenario building exercise explored in Measure 2 in the sense that a sector-integrated approach would be adopted throughout the entire NDP process, including in the quantitative modelling work supporting the selection of projects and investment decisions.

Table 13: Overview of impacts for the options under problem area III

Options relative to BAU	Option 1	Option 2	Option 3
Economic	+	++	+++
Environmental	+	++	+++
Efficiency	+++	+++	++
Effectiveness			
Driver 1: Variety/lack of integration	+	++	+++
Driver 2: Transparency	+	++	+
Driver 3: DSO involvement	-	++	+
+,++,+++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)			

7.4 Comparison of options for addressing lack of consumer engagement and protection in the green gas retail market

Although there is a significant level of uncertainty in quantifying the benefits of the options in this Problem Area, all options, except for Option 0 (baseline scenario), are expected to improve retail competition and integration of renewable and low carbon gases. However, the anticipated effectiveness and efficiency of the different options vary markedly.

Option 1 (Non-regulatory approach): can be expected to lead to modest, albeit tangible, economic benefits primarily as a result of the voluntary phase-out of regulated prices in some Member States and the drive to eliminate all switching-related charges. Given its low implementation costs, it is a highly efficient option. However, the effectiveness of Option 1 is significantly limited by the fact that non-regulatory measures are unlikely to ensure a consistent consumer engagement and protection throughout the EU and it is not suitable for tackling the slow **smart metering** deployment and the poor **data flow** or for significantly improving **consumer engagement.** They also introduce great uncertainty around the drive to phase out price regulation.

Option 2 (Flexible legislation): would probably lead to substantial economic benefits. Retail competition would be improved and customers would have better information on consumption and energy sources. Taken together these are effective tools to make greener choices, this option has a potential positive impact on the environment. Energy communities-of-interest would contribute to the uptake of biomethane and low-carbon gases.

Given that Option 2 would entail moderate implementation costs (primarily from ensuring a standardised format for consumer **data**, and the various burdens, such as the costs for rolling out **smart metering** (Option 2b), associated with improving **consumer engagement**) it is an efficient option as these costs are considerably outweighed by the benefits. Many stakeholder groupings are likely to be positively and negatively affected by the collection of policy measures in Option 2. But none would bear a disproportionate burden that would not be offset by commensurate benefits. Likewise, the proposed measures in Option 2 respect the principle and limits of subsidiarity.

Option 3 (Harmonization and extensive consumer safeguards): would also lead to substantial economic benefits, albeit with a greater degree of uncertainty over the size of these benefits. This uncertainty stems from the difficulty of prescribing EU-level solutions in many areas (for example implementing a standard EU bill design). Also a high administrative cost for public authorities can be expected from setting up and rolling-out a **smart metering** as well as from implementing the additional support measures for **energy communities**.

Whilst a single EU *data management* model would be just as effective and easier to enforce, and whilst the energy poor and vulnerable consumers would be even better protected by the stronger safeguards proposed, the high implementation cost of these measures would reduce the efficiency of Option 3 compared with Option 2. Finally as social policy is a primary competence of Member States, Option 3 may go beyond the boundaries of subsidiarity. Suppliers and DSOs in particular would face significant burdens that they would at least partially pass on to consumers i.e. socialise.

Table 14: Overview of impacts for the options under problem area IV

Options relative to BAU	Option 0	Option 1	Option 2	Option 3
Economic	+	+	+++	++
Environmental	+	+	+++	+++
Efficiency	+	+	+++	+
Effectiveness				
Driver 1: Untapped market potential	+	+	+++	+++
Driver 2: Consumer empowerement	+	+	+++	+++
Driver 3: Consumer protection	+	+	++	+++
+,++,+++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

8 PREFERRED OPTIONS

8.1 Problem Area I; Hydrogen infrastructure and markets

In light of the analysis the preferred option is option 2b ‘Main regulatory principles with a vision’. This option is best adapted to the particularities of the hydrogen sector and eenshrined in option 2b are already some of the benefits that Option 1, 2a and also 3b could have brought whilst avoiding the downsides. Option 2b can however still be improved by already providing the possibility to define and adopt, but only if and when required, detailed technical rules, which is part of Option 3a and b.

In more details the implementation of option 2b could include:

- A set of main regulatory principles that provide a clear perspective on the regulatory principles that will govern hydrogen networks the sector in the longer run and based on a ‘competition in the market approach', such as regulated, cost-reflective TPA and separate RABs and guarantees for neutral network operations based on ownership unbundling or an ISO approach. Rules for large scale storage and import terminals would seek the same objective but are adapted and rendered proportional to their particular economic circumstances;
- Measures that avoid impediments to cross-border integration and efficient markets, such as may result from hydrogen gas quality issues, and providing the prospect of a true level playing field, without cross-border tariffs;
- A transitionary phase in which financial flows between RABs are not excluded and during which negotiated TPA and tariffs remain possible provides flexibility to finance the ramp-up phase of the hydrogen network;
- Gas TSOs provide transparency on the gas infrastructure that may be available for repurposing whilst, in order to ensure that hydrogen infrastructure is only built if and when needed, a market test is imposed as the basis for the regulatory approval of regulated investments. Such an approach seems best-adapted to the more project based infrastructure development at the earlier ramp-up stages;
- Rules that facilitate the repurposing of natural gas assets and building new hydrogen infrastructure by grandfathering e.g. permits and land-use rights and ensuring that permits and land-use rights relevant for new hydrogen permits are granted in manners equivalent to those for natural gas;
- Fosters private investments, under an exemption regime for existing and new private network investments combined with rules that foster market integration by avoiding the permanent existence of divergent regulatory regimes within the same inter-connected network. Provision can be made for private networks could also be offered an opt-in into the regulated system;
- A light regime of consumer protection rules, suitable for more sophisticated hydrogen consumers, aligned to those enshrined in the Gas Directive;
- A legal mandate to introduce more detailed technical rules (network codes), if and when required;
- An appropriate governance system based on NRA supervision and ACER competences where needed.

8.2 Problem area II: Renewable and low-carbon gases in the existing gas infrastructure and markets, and energy security

In light of the analysis the preferred option is option 3 as it contains maximum of measures to support renewable and low carbon gases (including limitation of long-term contracts for natural gas), without the market impacts, complexity of the measures (and related administrative costs) and uncertain impacts on renewable and low carbon gases, included in option 4. As option 3 builds on the previous options, it includes elements of option 2. Also, some elements of option 4 could be maintained in the preferred option. In more details the implementation of option 3 could include:

- Access of renewable and low carbon RES&LC to the wholesale market will be enabled by ensuring gas flows from DSO to TSO by obliging DSOs to invest in reverse flows or agree with TSOs equivalent regulatory measures
- The costs of renewable and low carbon production would be lowered by a possibility to release producers from injection and connection costs (tariffs).
- Ban on long-term contracts for natural gas as of 2050.
- Abolishment of cross-border tariffs for renewable and low carbon gases only, measures for transparency of allowed revenue, costs benchmarking.

- Reinforced cross-border coordination on gas quality and harmonised EU approach on gas quality management to avoid cross-border flow restriction and market segmentation.
- 5% allowed cap for methane blends at cross-border points, which TSOs must accept (but without setting a blending obligation), enabling the integration of 70 TWh/year hydrogen at an adaptation cost of 3 Bn€/year.
- Rules on energy communities from the discarder option and assessed under problem area IV.
- Rules on energy security (including on cybersecurity) adapted to the decarbonisation of the gas sector.

8.3 Problem area III: Integrated network planning

Most suitable option appears option 2. This option provides the best balance in terms of achieving the objective of more integrated planning allowing for a conceptual energy system plan potentially indicating areas where sector coupling technologies are best located from a network perspective, but leaving the required level of detail sector specific. It addresses all identified drivers of the problem, but in a less intrusive manner than option 3, taking into account subsidiarity and proportionality

8.4 Problem area IV: Low level of customer engagement and protection in the green gas retail market

In light of the analysis, the preferred option is Option 2 Flexible legislation, which mirrors the electricity market customer protection and where relevant the empowerment provisions (as in Option 2b for smart metering). This option is most likely to be the most effective, efficient, and consistent with other Problem areas. Most stakeholders would support the measures envisaged in this option. This approach addresses problems stakeholders have highlighted in the OPC (notably calls for consistency of customer protection and empowerment across sectors) while accommodating national differences in retail markets. Burdens for national administrations and businesses are limited and implementation can build on the experience with the clean energy package.

8.5 REFIT (simplification and improved efficiency)

The proposals for amending the existing legislation will be designed in accordance with the most cost-effective policy options scrutinised in this impact assessment. It is expected from some of the preferred options to increase administrative, implementation and enforcement costs for both regulatory bodies and market operators. For example, higher administrative exchanges between NRAs and natural gas shippers, increased coordination efforts between DSOs and TSOs, and further regulatory and implementation efforts for Member States and national authorities might stem from the proposed measures. However, lower and more efficient regulatory costs are also expected from the amended framework, as substantiated in the table below.

Furthermore, the analysis in the impact assessment clearly shows that the proposed measures offer the most cost-effective regulatory options to achieve the overarching objective of the initiative, namely the establishment of rules for the transmission, distribution, supply and storage of methane and hydrogen gases that can support the decarbonisation of the energy system while ensuring secure and affordable energy.

The short-term regulatory costs entailed in some of the preferred measures must be also assessed against the costs and efforts that a late integration and decarbonisation of the energy system would require in the long term. In this sense, the benefits that the options are expected to produce in terms of support for renewables sources, energy system integration, consumer protection and energy security will largely outweigh the immediate administrative and implementation costs.

The proposal further contributes to simplifying the current regulatory framework by harmonising, when necessary and appropriate, the provisions on gas infrastructure and market with the new regulatory architecture conceived by the Clean Energy Package for the electricity sector. Higher alignment between sectors is expected to benefit many regulatory areas, notably consumer empowerment and protection, governance and regulatory oversight. Similar contributions are also foreseen in the early introduction of a regulatory framework for hydrogen infrastructures and markets. Whilst these rules will likely increase the immediate administrative costs and regulatory burdens for national authorities and market operators, an early harmonisation of regulatory principles for hydrogen is expected to significantly lower future compliance costs and prevent the risk of major regulatory divergences and implementation costs.

Table 15: REFIT cost savings

REFIT Cost Savings – Preferred Option(s)		
Description	**Amount**	**Comments**
Regulation for hydrogen infrastructure and markets	N/A	It can reduce transaction and administrative costs for renewable hydrogen producers or suppliers that want to supply (distant) consumers with (cross-border) produced renewable hydrogen
Access of renewable and low carbon gases to the gas markets and infrastructure	N/A	Potential to reduce state aid with increased efficiency of biomethane production and trade
Adoption of an allowed cap for hydrogen blends cross-border	N/A	Reduces the administrative work for market operators in the gas system by increasing the homogenisation of European gas market characteristics and reduce the need for justification for exception and interaction with different TSOs
Establishing a system-wide NDP	N/A	Biomethane and hydrogen producers are expected to benefits from interacting with a single and joint planning exercise of TSOs
Ensuring non-discriminatory access to data, and in fact smart metering data	N/A	In countries where smart meters are rolled out, **DSOs** can lighten, and improve, some administrative processes (linked to meter reading, billing, disconnection, etc.), and offer increased customer services.

(1) Estimates are with respect to the baseline of the unchanged legislation; (2) Please indicate which stakeholder group is the recipient of the cost saving in the comment section; (3) For reductions in regulatory costs please describe the measure/action which gives rise to the cost saving (e.g. actions to reduce compliance costs, administrative costs, regulatory charges, etc.) and whether it is a recurrent cost saving.

9 HOW WILL ACTUAL IMPACTS BE MONITORED AND EVALUATED?

9.1 Future monitoring and evaluation plan

The Commission will systematically monitor the transposition and compliance of the Member States and other actors with the finally adopted measures and take enforcement measures if and when required and report on the progress made in this regard on a regular basis. For this purpose, the Commission will be supported by ACER as described below.

The annual reporting by ACER and the evaluation by the Commission are part of the proposed initiatives and described in the sections below.

The energy security impacts will be monitored as a part of the overall monitoring tasks under the SoS Regulation, such as the Commission's opinions on the national preventive action and emergency plans.

9.2 Annual reporting by ACER and evaluation by the Commission

The monitoring of the proposed initiatives will be carried out following a two tier approach: annual reporting by ACER and an evaluation by the Commission.

9.2.1 Annual reporting by ACER

ACER's duties under the Third Package[144] and the Clean Energy Package[145] include the monitoring of and reporting on the internal gas market. ACER prepares and publishes an annual market monitoring report that tracks the progress of the integration process and the performance of gas markets and identifies any barriers to the completion of the internal gas retail and wholesale markets.

Based on the present proposals, ACER will continue to monitor and report on the internal gas market on an annual basis after the adoption of the proposals. Its mandate will be extended to include hydrogen. ACER's annual reporting will replace the Commission's reporting obligations that are currently still existing under the Gas Directive.

9.2.2 *Evaluation by the Commission*

The Commission will carry out a fully-fledged evaluation of the impact of the proposed initiatives, including the effectiveness, efficiency, continuing coherence and relevance of the proposals, within a given timeline after the entry into force of the adopted measures (indicatively, 5 years).

The evaluation report will be developed by the Commission with the assistance of external experts and stakeholders will be informed of and consulted on the evaluation report. Stakeholders will also be regularly informed of the progress of the evaluation and its findings. The evaluation report will be made public.

9.3 Operational objectives

The key objective of the present initiative is to contribute to the EU's decarbonisation in a cost-effective manner by facilitating the creation of a European hydrogen market and the gradual decarbonisation of gaseous fuels markets, whilst ensuring energy security. The operational objectives for the preferred options are to adopt the measures as described in section 8.

9.4 Monitoring indicators and benchmarks

Within one year of the adoption of this proposal, ACER will be invited to review its current monitoring indicators with a view to ensure their continuing relevance for monitoring progress towards the objectives underlying the present proposals. ACER will continue relying on the same sources of data used for the preparation of the market monitoring report. Monitoring indicators could include, but not limited to, the followings:

Indicators for *Problem area I* related to the hydrogen infrastructure development and utilisation (e.g. transportation capacity, large scale storage and import terminals) the development of a competitive, integrated hydrogen market.

Indicators for *Problem area II* related to the levels of production, production costs, and the level of trade and access of renewable and low carbon gases to markets (including volumes and number of traders) and of the utilisation rates of LNG terminals and volumes of these gases received.

Indicators for *Problem area III* existence of joint scenario framework, level of involvement of different sectors in network planning, level of interconnectivity and provision of flexibility between sectors, consistency of NDPs with TYNDP.

Indicators for *Problem area IV* related to the levels of availability, security of supply and unit price for end-consumers, competition in the retail market (market shares and prices) and energy poverty.

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[144] The legal basis for the Agency's market monitoring duties is in Article 9 of Regulation (EC) No. 715/2009. ACER equally monitors and reports on many more detailed aspects of the regulatory framework.

[145] Including additional monitoring tasks as envisaged in Article 15 of the Regulation (EU) 2019/942 (recast ACER Regulation), available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0942&from=EN.