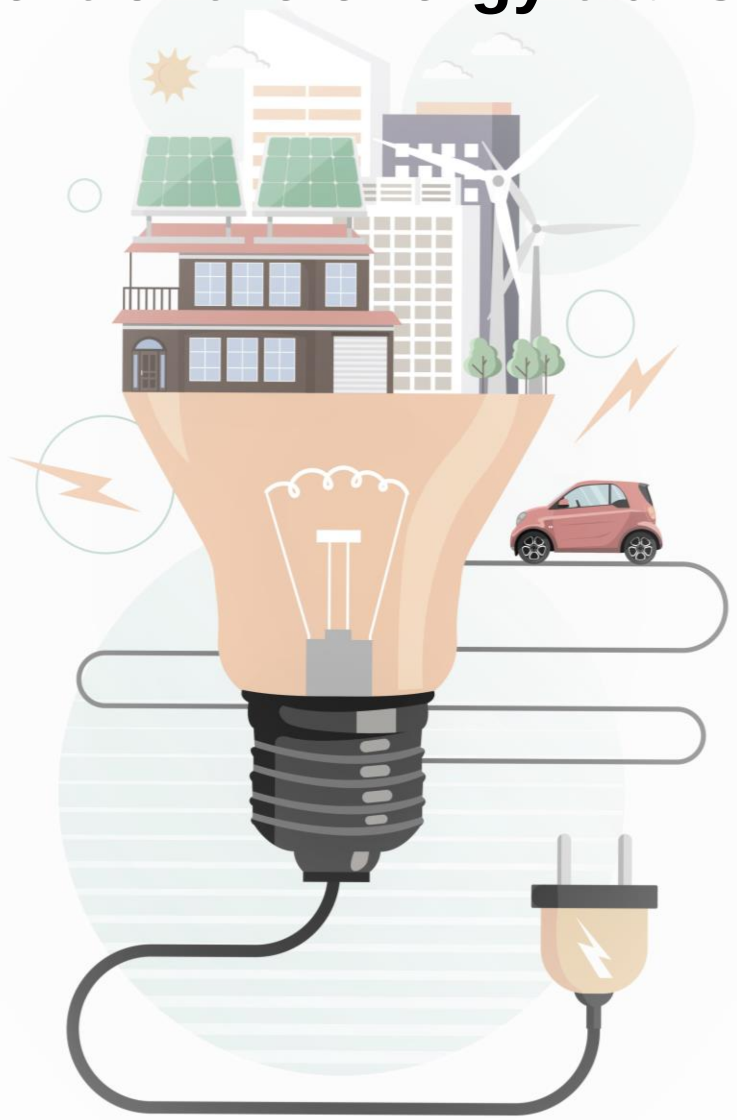
ASSET Study on

The role of Gas DSOs and distribution networks in the context of the energy transition



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About ASSET

ASSET (Advanced System Studies for Energy Transition) is an EU funded project, which aims at providing studies in support to EU policymaking, including for research and innovation. Topics of the studies will include aspects such as consumers, demand-response, smart meters, smart grids, storage, etc., not only in terms of technologies but also in terms of regulations, market design and business models. Connections with other networks such as gas (e.g. security of supply) and heat (e.g. district heating, heating and cooling) as well as synergies between these networks are among the topics to study. The rest of the effort will deal with heating and cooling, energy efficiency in houses, buildings and cities and associated smart energy systems, as well as use of biomass for energy applications, etc. Foresight of the EU energy system at horizons 2030, 2050 can also be of interests.

The ASSET project will run for 36 months (2017-2019) and is implemented by a Consortium led by Tractebel with Ecofys and E3-Modelling as partners.

Disclaimer

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This study has been developed as part of the ASSET project by E3 Modelling

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Executive summary

The focus of the European policy on natural gas is evolving from market integration, competition and security of supply towards sustainability. Long term (2050) decarbonisation objectives are expected to be fulfilled by energy efficiency actions and further additions of renewables in the energy mix including the injection of gases of reduced carbon footprint into transmission and distribution networks. Moreover, in the context of the European Green Deal, decarbonisation of the gas sector will have to be facilitated, including through the development of decarbonised gases based on a competitive decarbonised gas market, and by addressing the issue of energy-related methane emissions[1]. This study aims to

- Evaluate the existing EU framework as set mainly by Directive 2009/73/EC and identify barriers and gaps that may prevent the injection of new gases at distribution level.
- Assess the need for new rules and/or market arrangements at EU level concerning: the operation and planning aspects of distribution networks including specific issues related to flexibility and storage; Issues related to the injection of gases at distribution level; Interoperability issues that may rise from the blending of gaseous fuels.
- Examine the role of gas Distribution System Operators (DSOs) and distribution networks under a new environment, shaped by the penetration of biogas, hydrogen and power to gas technologies.
- Assess the need and different options for formal representation of gas DSOs at EU level.

Further, the study aims to determine the need for further clarity in the role of the DSO for example the role of DSOs in measuring gas quality and the need for compliance to standards for the carbon footprint of the injected blend of gaseous fuels.

The study comprises of three workstreams. The first workstream includes a review of the current status of EU markets regarding the penetration of new gases and an analysis of the scenarios quantified by the PRIMES model in the context of the European Long-Term Strategic Vision[2] with emphasis on distribution networks.

A second workstream focused on a review of the national framework of selected EU Member States in relation to gas distribution. The following countries have been considered: Austria, France, Germany, Italy and the Netherlands.
The third workstream includes a comprehensive review of the EU legal framework i.e. Directive 2009/73/EC[3] (hereinafter the 'Gas Directive') and Regulation (EU) 715/2009[4] (hereinafter the 'Regulation') with a view to identify barriers and gaps that may prevent the injection of new gases at distribution level. While distribution networks are not in the scope of the Regulation, a review was carried out with a view to identify relevant best practices that could be extrapolated also to distribution. The European gas network

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[1] Commission Communication COM(2019) 640 final *"The European Green Deal"*.
[2] Commission Communication COM(2018) 733 "*A Clean Planet for all: A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy"*.
[3] Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC
[4] Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (consolidated version)

codes (Regulations (EU) 312/2014[5], 2015/703[6], 2017/459[7] and 2017/460[8]) were also considered, although currently these are also not applicable to distribution (or only applicable under conditions as is the case of Regulations (EU) 312/2014 and 2015/703). We further looked into the relevance of the revised Electricity Directive (Directive (EU) 2019/944) and Regulation (EU) 2019/943 and the results and recommendations included in other studies and publications, such as the recent publications of ACER and CEER regarding the new role of distribution system operators, as well as the 'sector coupling study'[9]. Our own review was checked against, and complemented by input from European institutions and stakeholders who were invited to express their views. Their input is gratefully acknowledged.

Finally, a set of recommendations for potential actions at EU level were formulated.

Sectoral projections of natural gas and new gases

E3Modelling has provided quantitative modelling (using the PRIMES model) to the in-depth analysis[10] published by the Commission on 28 November 2018 in support to its Long-term Strategic Vision. For the purpose of this study we further analysed the implications on the gas distribution networks of the following scenarios the Hydrogen (H2) and Power-to-X (P2X) scenarios, as well as 3 additional scenarios (COMBO, 1.5 TECH and 1.5LIFE) considered in the Commission's in-depth analysis of the Long-Term Strategic Vision.

- The H2 scenario foresees high deployment of hydrogen in final uses in transport, buildings and industry, benefiting from possible applications that are currently known. This is facilitated by properly adjusting the gas distribution grid and heating equipment to accommodate high shares of hydrogen (allowing for a mix up to 50% in gas distribution in 2050 and 70% in 2070).
- The P2X scenario is similar to the H2 scenario, but hydrogen becomes mainly an intermediate feedstock for the production of e-fuels (e-gas and e-liquids). Towards 2050, hydrogen is produced by electrolysis, e-gas by methanation plants and e-liquids via various chemical routes, notably the methanol route and the Fischer-Tropsch process. To be carbon neutral, both e-gas and e-fuel production use CO_2 captured from the ambient air or biomass-using power plants.
- COMBO combines effective solutions for each sector/mode from the scenarios ELEC, H2, P2X and EE. COMBO does not push for extreme deployment of specific technologies or actions.
- 1.5TECH is similar to COMBO but with more ambitious decarbonisation. It assumes limited additional incentives to improve the land use sink. It increases CCS aiming to further reduce the remaining emissions and consumes more e-gases and fuels based on air captured or biogenic, than COMBO.

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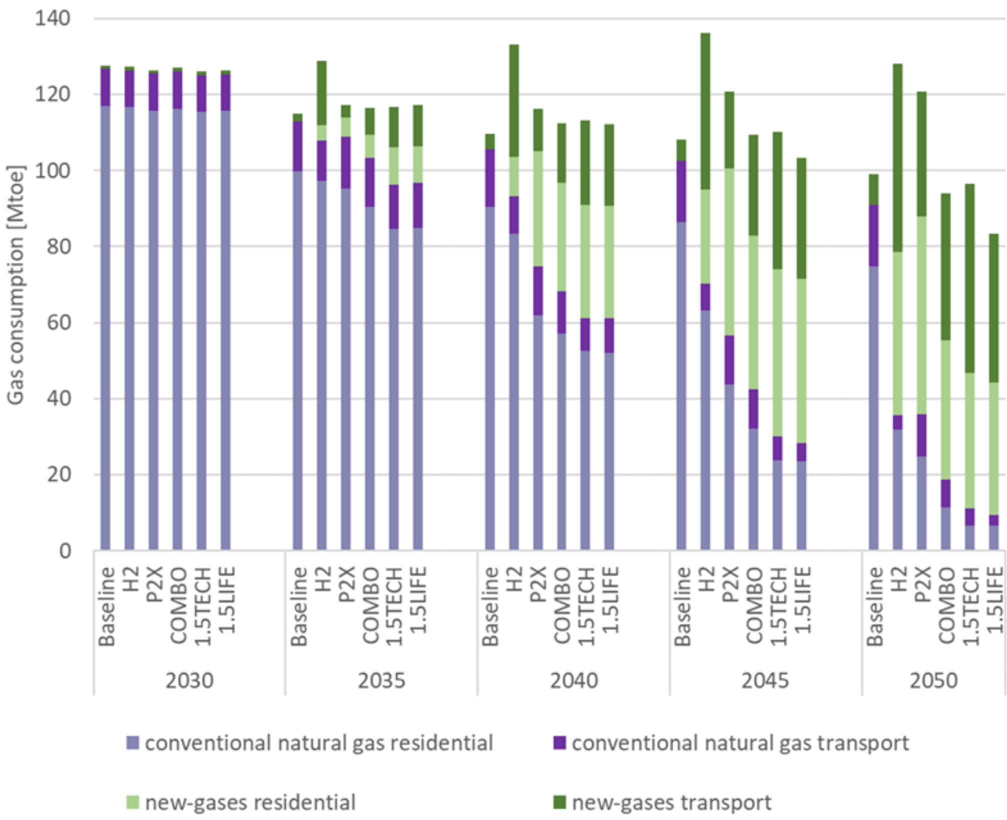
[5] Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks
[6] Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rule
[7] Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013
[8] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
[9] Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU, https://ec.europa.eu/info/sites/info/files/frontier_-_potentials_of_sector_coupling_for_decarbonisation.pdf
[10] https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

- 1.5LIFE is similar to COMBO but with behavioural changes rather than technical solutions to induce emission reductions beyond the COMBO scenario: these include higher modal shifts for transport and circular economy, as well as diet changes.

The H2 and P2X scenarios have an 80% GHG emission reduction target, whereas the COMBO scenario has a reduction target of 90%. The 1.5 scenarios (1.5 TECH and LIFE) achieve 100% emission reduction (incl. sinks).

Total consumption of gas (fossil and new gas) at distribution level (source PRIMES)



In all scenarios, consumption of conventional (fossil) natural gas (excluding non-energy use) is severely reduced by 2050. The reduction in gas consumption impacts the residential and services sectors serviced by distribution networks.

A moderately decreasing trend in natural gas consumption of the order of 10-12% in the period post 2020 and till 2025 (in comparison to 2020 levels) is also observed. This is followed by an additional substantial reduction of -15% in 2030 (in comparison to 2025 levels). From 2035 onwards, values vary depending on the scenario. The reduction of natural gas demand in the residential and services sectors (mainly for heating) is driven by increased energy efficiency, electrification trends and substitution of natural gas with biogas, hydrogen and e-gases post 2030. In 2035 the penetration of new gases in distribution is projected of the order of 10% at EU level. Moreover, in 2040, pipeline gas is composed of up to 12% hydrogen in the H2 scenario and up to 50% of conventional natural gas is replaced by GHG free gas and biogas in the remaining scenarios. In 2045 and 2050, new gases exceed the amount of fossil natural gas in the network. In 2045 and 2050, new gases exceed the amount of fossil natural gas in distribution networks. Total gas demand in 2050 for the residential and transport sector is of the order of 80-130 Mtoe depending on the scenario with new gases amounting to 25 to 56

Mtoe. In comparison the 2015 gas consumption (residential and transport sectors) was of the order of 173 Mtoe (EU-27 and UK).

Clearly, subject to additional enabling conditions (e.g. substantial financial support and faster technological maturity than the one foreseen in the scenarios of the Long-term Strategic Vision), penetration of hydrogen and other new gases in the distribution network could occur even earlier in time.

Evolving role of DSOS and new-gases in energy transition and steady state towards 2050

As indicated by the scenarios in the Long-term Strategic Vision (as summarised above), introduction of new gases in distribution networks is expected to be a long term gradual process, starting with a transitional phase from the early twenties to about 2045 and followed by a steady state around and post 2050 when most of fossil natural gas is expected to be displaced from European networks. This study examined potential gaps in the EU legal framework to accommodate both the transitional and the steady state periods. Conceptual views of both periods are shown in the figures below.

During the 'energy transition' phase, natural gas shall continue to be introduced at transmission level, while new gas production facilities (mainly biomethane) will increasingly connect at distribution. Small quantities of hydrogen are anticipated, mostly towards the end of the transition period e.g. 2035-2045. DSOs shall need to develop in a timely manner (and NRAs to approve) a relevant regulatory framework with standardised connection contracts for gas injection and non-discriminating access conditions for producers willing to connect their facilities at distribution level.

Moreover, network planning and development shall become an important part of the DSO tasks. Distribution system development plans shall have to account for the increasing injection of new gases. New investments in compressors to inject new gas in transmission and odorant removal facilities will have to be considered towards the end of the transition period, accompanied by the development of new rules for the allocation of costs between transmission and distribution networks. DSOs shall be also undertaking relevant studies to quantify the technical implications of accepting higher hydrogen blends in their networks.

The role of the DSO in daily network operation shall be expanded to include obligations for gas quality metering and monitoring and also for quality and injection forecasts. Network pressure monitoring procedures and linepack operation will become more diligent towards the end of the transition period and methodologies for the optimal use of linepack may need to be developed. In the context of additional need for flexibility at distribution level, commercial use of linepack may be considered together with doubling of pipelines and local storages towards the end of the transitional phase. Tariff methodologies for the use of the distribution system may need to be revised to take into account gas injection (including injection to transmission) and also offering of interruptible services. Enhanced and structured cooperation between TSOs and DSOs shall need to be in place to address both network development and operation such as physical flows from distribution to transmission. Communication between DSOs, consumers and producers is expected to be increasingly based on smart solutions.

During energy transition, the development of dedicated hydrogen networks for industrial customers shall continue and may be promoted in the context of greening the industrial sector. Need for regulation of such networks is not expected to rise but only towards the end of energy transition.

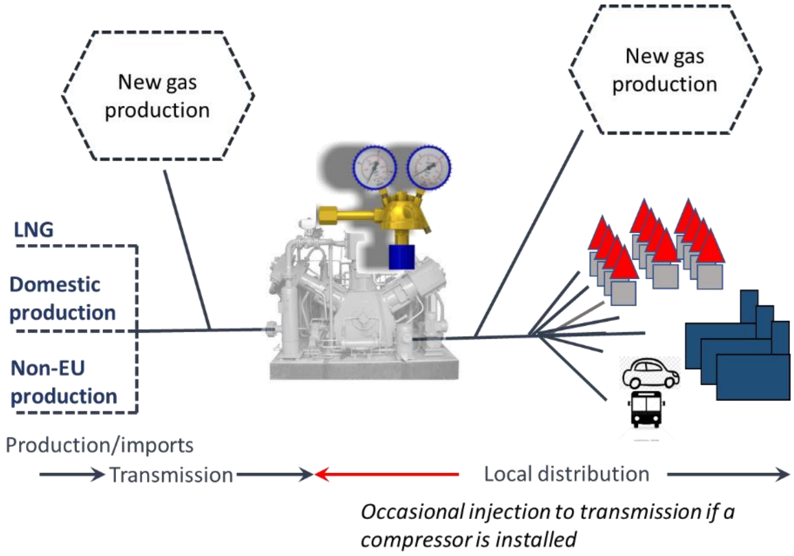
New-gas producers shall have to conclude bilateral contracts with suppliers and end-consumers and/or become active participants at the local Virtual Trading Point (VTP) throughout the transition period. As new market entrants, new-gas producers may face additional entry barriers both in the wholesale and also in the retail gas markets. End consumer switching to green products may be limited due to lack of awareness, increased costs and other administrative complexities related to switching. Obligations for a certain percentage of new-gases to be included in the suppliers' energy mix and mix disclosure obligations may facilitate penetration.

As new-gases come with a variety of combustion properties and carbon content, a Guarantees of origin (GO) market focusing on new-gas GOs is gradually developed. Given experience with electricity, rules for GO market operation cross-border harmonisation shall be a process that can be concluded comparatively early in the transition period.

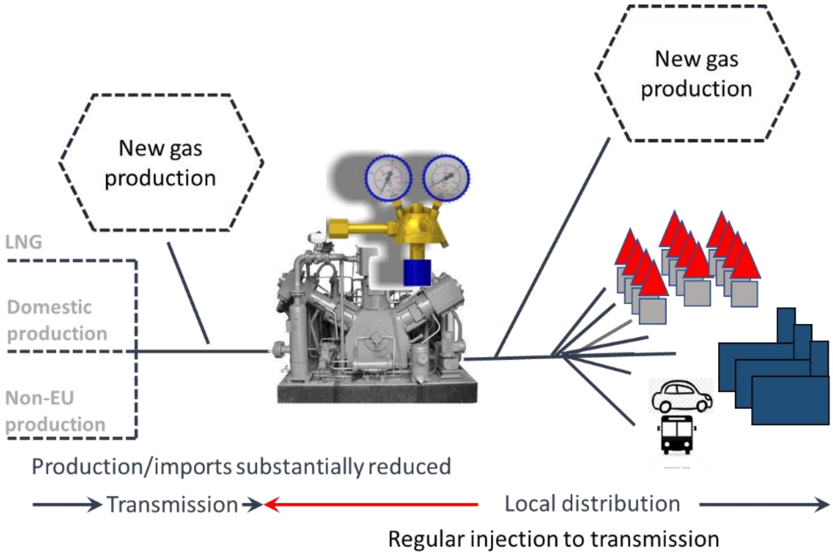
Around 2050 a 'steady state' is achieved where the injection of new gases including hydrogen is substantial. Technical barriers related to the acceptance of hydrogen injection will be resolved. Fossil gas injections at transmission level will be significantly reduced. Dedicated hydrogen networks shall also serve a variety of end consumers and shall be subject to regulation as is currently the case for gas networks.

Transmission and distribution networks are integrated due to the installation of compressors which allow for bidirectional flow of gas and market rules that do not restrict the trade of gas regardless the network used are in place. Smart quality sensors are installed at all network branches in order to better monitor the physical and chemical properties of gases injected in the grid. Non-discriminatory access conditions for producers to connect at distribution level are well established in all Member States. Gas quality standards are relaxed and based more on fluid mechanical and combustion characteristics rather than composition, as is nowadays the case with oil products and lubricants. A national entity integrating electricity and gas TSOs and connected DSOs is established to facilitate coordination.

Conceptual view of gas networks during energy transition

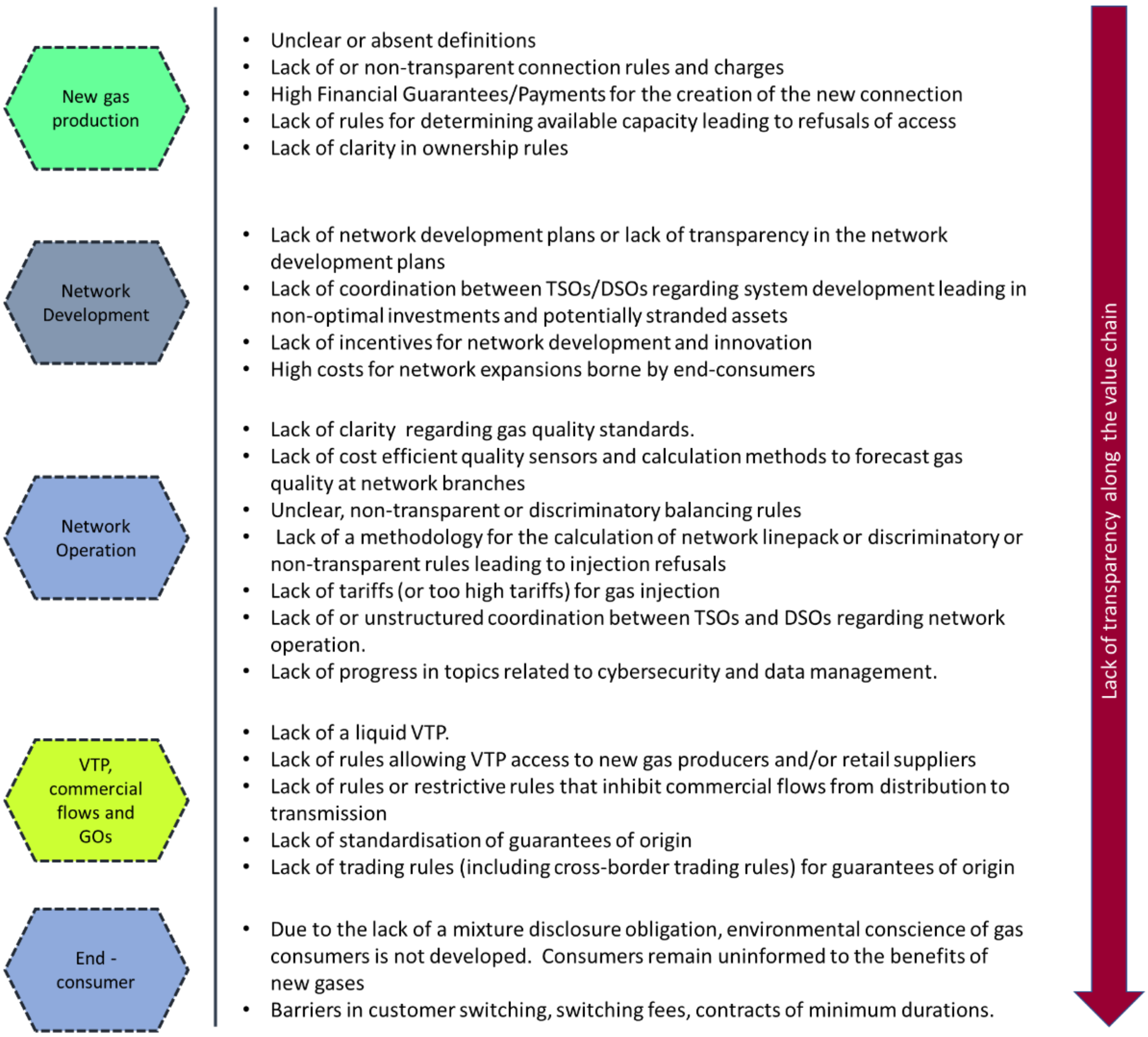


Conceptual view of gas networks at steady state



Potential regulatory gaps or barriers

Transition to a new-gas dominated system requires changes to existing regulatory frameworks in many Member States and potentially also at EU level to promote new-gases, ensure non-discriminatory access to networks and safeguard that new-gas penetration is not to the detriment of the internal market. As part of this study, a value chain analysis of potential regulatory gaps and barriers as summarised in the figure below was undertaken. Our analysis looks into new-gas production per se (definitions, connection and ownership rules), network development and operation (rules and standards including quality standards, incentives for innovation, tariffs, cost allocation, management of linepack), commercial flows, access to the VTP and guarantees of origin and finally upon topics related to end consumers (customer switching, awareness to gas of reduced carbon footprint). We shall be referring to this analysis as "regulatory benchmark". The benchmark has been used as a guide in our review of selected national frameworks and of the European framework.



National case studies

All countries reviewed in the context of this study (Austria, France, Germany, Italy, Netherlands) have adopted specific provisions regarding the connection and operation of new-gas production facilities. As anticipated, in countries with support schemes and specific targets for the penetration of new gases within specific deadlines, the regulatory framework is already established. France is an outstanding case with a solid commitment for 18-22 TWh of biomethane to be injected in gas networks (transmission and distribution) until 2028.

In most of the countries however, provisions are specific to biomethane and thereby the connection of other types of gases is excluded. Lack of specific rules for the connection and operation of new-gas plants is a clear barrier to entry.
Countries have established different regulations/provisions about who bears the costs for new connections (producers only as is the case in Italy or sharing between producers and network operators, e.g. in Germany and France). Second comer rules are also present in some cases (e.g. Germany, Italy for transmission). In both Italy and Germany, the legal framework foresees that if additional connections are added within ten years after the first grid connection on the same branch, the network operator must distribute the costs among connecting parties and reimburse first connectee(s) for any

additional amount paid. Grid expansions to accommodate new gases are often subject to a technoeconomic analysis according to a methodology set and approved by the NRA (e.g. France). A coherent distribution network planning takes place in all Member States reviewed and new-gas connection requirements and requests are taken into account in the development plan.

Connection of a new-gas production facility on a distribution network inherently implies the allocation of a certain distribution capacity to the connectee. Connections and capacity allocation are typically on a first-come-first served basis. It is understood that DSOs perform hydraulic simulations based on data collected from specific points in the network equipped with pressure meters. From such data and calculations, they estimate the network potential to accept new connections for new-gas injection. In networks equipped with smart meters, linepack calculation on an hourly level is also possible. However information on the capacity of the network to accept new-gas connections is not typically published. Conditions upon which a connection may be refused are often unclear and connection times are not always specified.

DSOs have the right to refuse injection of new gases into the network on grounds of quality, odourisation and lack of capacity. The methodology and criteria upon which injection is refused are not well specified. We have not been able to identify clear obligations upon DSOs for the maximisation of linepack utilisation and optimisation in network operation. In some countries (e.g. Germany), biomethane is injected with priority in comparison to natural gas and new gas plants are excluded from typical (and more stringent) balancing obligations applicable to all other suppliers.

The websites of distribution system operators in most cases do not include information on how to connect a new-gas plant and there are no links to the applicable connection rules, costs and times. The current legal/regulatory framework only imposes limited transparency obligations upon DSOs. Information on critical technical parameters such as quality and pressure is also not published. We note, as we also discuss below, an overall lack of reporting obligations and absence of transparency templates as those developed and used by TSOs, LNG and storage systems operators across EU. Typically, information, if any, is only available at national languages.

In the Member States reviewed, system operators are actively involved in technical assessments regarding hydrogen injection. This includes indicatively Snam Rete Gas in Italy and GrDF in France. In the Netherlands, the TSO Gasunie together with DSOs are focussing on a design of alternative distribution-level storage solutions to account for the seasonality of gas consumption amidst continuous new-gas production. We have not identified cases where a DSO is directly involved in a new-gas production facility in the sense of owning such a facility and/or the gas produced. Such a detailed investigation – DSO-by-DSO- was not in the scope of the present study.

Analysis of the EU framework for the internal gas market

The EU framework on natural gas (and also biogas and gas from biomass or other types of gas) is defined by the Gas Directive (Directive 2009/73/EC), Regulation (EC) No. 715/2009 and the European Network Codes[11]. The Gas Directive establishes common rules for the organisation and functioning of the overall natural gas sector (transmission, distribution, supply and storage). Then Regulation (EC) No 715/2009 and the European Network Codes specify further rules, mostly for transmission, with a view to ensure mainly the harmonisation of access conditions at cross-border interconnection points and facilitate the emergence of a well-functioning wholesale market.

[11] By European Network Codes we refer collectively to Regulations (EU) 312/2014,2015/703,2017/459, 2017/460.

Regulation of distribution networks at European level assumes a lighter form than that for transmission infrastructure as the latter was considered more key to market integration than the former. The adoption of lighter regulation for distribution was also due to the vast number of European DSOs of different sizes both in terms of network length and connected customers.

Introduction of production of new gases at distribution level, in the context of an internal functioning gas market, inherently implies a gradual integration of transmission and distribution. Also considering sector coupling, it is clear that there seems to be an overall general trend towards the integration of energy infrastructure (transmission, distribution, electricity, gas). Within a decarbonised future, sector integration may be further expanded to also include transport and heat.

Main findings and high-level recommendations

In this study we reviewed Directive 2009/73/EC and the gas Regulations, where appropriate or relevant, with a view to identify restrictive clauses or gaps to the penetration of new-gases that need to be addressed at European level. It is important to note that the scope of the overall European framework for gas focuses on market integration through 3 main axes: competition, security of supply and sustainability. The Directive provides for general principles such as the tasks of the NRAs, TSOs, DSO, unbundling rules and obligations and third-party access and tariff rules based on general non-discrimination principles. Implementation, regarding distribution, is then left mostly at national level. We have structured our recommendations with a view to maintain the original scope of the EU regulatory framework during energy transition (e.g. in a period from early 2020s to 2045) and latter at steady state (post 2050). This means that recommendations provided below are high level within a general scope to safeguard harmonisation across Member States and the internal market taking utmost note to the EU decarbonisation commitments.

Topic	Barrier identification and assessment	
Definition of New Gases and Standards		▪ The Directive does not foreclose the injection of new gases of any type in so far as such gases can technically and safely be injected. Implementation of this provision in Member States is subject to further scrutiny ▪ Technical and safety limits may not be fully defined (for example blending ratios for hydrogen.) Studies on the determination of acceptable blending ratios are under way . Absence of standards can be detrimental to the development of new gas production while too rigid standards can also hinder new gas development.
Definition of New Gas Facilities and New Gas Producers		▪ Directive 2009/73/EC in its current form does not provide a definition for production facilities and producers. ▪ As production is not in the scope of the Directive a definition may not be necessary - subject to the analysis regarding the involvement of DSOs in new gas facilities. ▪ On the other hand, a definition may be required by analogy to the existing provisions of the NED.
Regulation of new gas facilities		▪ Currently there are no provisions for the regulation of new gas facilities in the Directive.
Mix disclosure obligation		▪ The Directive does not foresee an obligation for suppliers to disclose the carbon and/or renewable content of their fuel mix
Access to VTP		▪ The EU legal framework and the GTM promote VTP access. Nevertheless, there are still several Member States with illiquid or non-functioning hubs. Access to VTPs for small new-gas suppliers may be have inherent challenges.
Customer switching		▪ The Directive imposes upon Member States several obligations towards facilitating customer switching. Still the CEER in a series of reports continuous to recognise barriers in the supplier switching process
Wholesale and retail licensing		▪ A system of mutual recognition for wholesale market authorisations/licences (or an equivalent mechanism) still does not exist at EU level. ▪ There is no mutual recognition for retail licenses
Licensing of new gas facilities		▪ Article 4 of the directive refers only to natural gas facilities with no provisions for biogas or other types of gas. Interviewees informed that in many countries there is legislation with reference to biogas, as a fuel for electricity but limited provisions for biomethane or other types of new gases for injection into transmission or distribution.
Safety standards for hydrogen and Blending limits		▪ Undefined standards for hydrogen including blending limits. Lack of a roadmap for reaching an agreement on blending limits at least on national level.
Lack of clarity in the ownership of DSOs of new gas plants		▪ DSOs with less than 100,000 customers can own a production facility without any unbundling obligations ▪ As there is no definition of a new-gas plant in the Directive, the legal framework is unclear. This includes also access conditions in case the production facility provides a conversion service to more than one users
Role of the DSOs in relation to connecting new gas facilities		▪ The Directive includes no provisions related to the obligation of the DSO to connect new gas facilities.
Role of the regarding the promotion of RES		▪ The Directive does not include specific provisions

Topic	Barrier identification and assessment	
Cooperation between TSOs and DSOs	Red	▪ No specific form is specified. No formal obligations for cooperation
Flexibility upon DSOs to carry out other services subject to NRA approval	Red	▪ No such provisions exist in the Gas Directive
Role on DSOs regarding gas quality measurements	Red	▪ The EU framework neither assigns an explicit role on DSOs for gas quality metering and monitoring nor does it address the need for the development of smart and affordable quality meters and their installation in networks.
Storage and Linepack	Green/red	▪ The scope of the Directive on linepack provisions touches also upon distribution. ▪ IT is subject to interpretation whether existing provisions on storage are applicable to distribution.
DSO and TSO cooperation and network planning	Red	▪ The Directive does not impose an obligation upon DSOs for the creation of network development plans. ▪ There are no provisions for a structured TSO/DSO cooperation during network development planning. ▪ No specific provisions for cooperation between electricity and gas operators
Drivers to innovation and incentives	Red	▪ Directive 2009/73/EC includes only a minor reference to the need for innovation
Role of NRAs regarding new-gases	Red	▪ Directive 2009/73/EC does not include specific provisions for the role of NRAs regarding monitoring of new-gas production and DSO monitoring in relation to new gases.

legend

- (green/red) The topic addressed is absent in the gas legal framework however its absence may not be necessarily a barrier to the penetration of new gases in European networks
- (red) The topic addressed is absent in the gas legal framework and its absence is considered a barrier to the penetration of new gases in European networks

a) Type of gas injected into the networks and gas disclosure obligations

The current legal framework at EU level is not restrictive to the type of gas injected into networks (including distribution networks). Article 1(2) of Directive 2009/73/EC is clear that the rules established by the Directive apply in a non-discriminatory way to biogas and gas from biomass or other types of gas in so far as such gases can technically and safely be injected into, and transported through, the natural gas system.

However, European stakeholders interviewed in the context of this study underlined the need for a definition of new gases. New gases may vary not only in terms of their composition (e.g. biomethane or hydrogen content) but also in their sustainability/renewable origin and their GHG footprint. Such a definition may need to be introduced at European level as well as obligations for network interoperability so as to ensure that there is no dilution of the internal market.

Overall, the practical implications on the injection of new gas mixtures to infrastructure and appliances should be further evaluated. Softer form of standards like the standards applicable for gasoil, gasoline or lubricants (based more on combustion and fluid mechanical characteristics rather than composition) may be required to ensure that gas quality does not become a barrier to integration of transmission and distribution in the steady-state period and also a barrier to cross-border trade leading to disintegration of the internal market. It is understood that a biomethane standard is in place (EN-16723) which accounts for biomethane for use in transport and biomethane for injection in the natural gas network, but no such standards exist for hydrogen yet.

We are further recommending the issuance of guarantees of origin (GOs) for every unit of gas injected into networks and that GOs are standardised so that they can be traded across Member States by analogy to the current practice in electricity. Further, as with electricity, a mixture disclosure obligation should be placed upon gas suppliers so that they inform their customers on the carbon content of the gas they deliver. If gas GOs remain a voluntary scheme, a gas residual mix methodology, as for electricity, should be developed. In our view these are topics that should be addressed at a European level so as to ensure the integrity of the internal market.

b) Definition of new-gas production facilities, new-gas producers and monitoring of new-gas facilities and production

Directive 2009/73/EC does not include a definition for a production facility, as it was reasonably inferred that the term production refers to the production of conventional (fossil) natural gas. A definition of new-gas production facilities should be consulted with stakeholders and considered in a potential future amendment of the Directive.

Reliable fundamental data on gas production assets (e.g. location in a GIS system, capacity, new-gas type, production), should be systematically collected from TSOs, DSOs and GO issuing bodies and submitted to the National Regulatory Authorities (NRAs). The relevant information should be available at European level. Metrics to evaluate progress in new gas installations and development of relevant regulation should be developed.

c) Access of new-gas suppliers to the wholesale and retail markets

The creation of well-integrated, competitive and liquid wholesale gas markets and competitive retail markets is a cornerstone of European policy. New-gas producers should be able to sell their production through bilateral contracts with retail suppliers or end-consumers (retail market) but also through the national or regional hub. There are two actions that may need to be undertaken in this direction.

Firstly, at retail level, customer switching should be facilitated, and existing barriers related to customer switching should be removed. A parallel study funded by the European Commission on Barriers in Retail Energy Markets[12] reports that new suppliers continue to face barriers to entry in the retail market and that customer switching is still not facilitated in a number of countries. It is upon national regulators to continue to promote the functioning of a transparent retail market. Extension of the scope of retail market monitoring may be considered either by legally strengthening the monitoring obligations of NRAs or through ACER/CEER reporting channels. Appropriate indicators for retail market functioning need to be defined. If indicators do not meet the thresholds, this would indicate retail market functioning concerns triggering NRA(s) to undertake a more detailed analysis of the situation as has been also recommended by ACER. Barriers in relation to retail supply licenses should be further investigated.

Secondly, access to a Virtual Trading Point (VTP) for new-gas producers should be facilitated. NRAs should review conditions for access at the relevant VTPs to ensure that there are no restrictions for players active on distribution to access the wholesale market. A system of mutual recognition of wholesale licenses should be established along the recommendation of ACER.

[12] Study on "Barriers to entry in retail energy markets‟ Webinar , 29 April 2019

d) Registration, licensing and technical requirements

In a potential future review of the Gas Directive there may be a scope to include a specific obligation that in circumstances where an authorisation is required for the construction or operation of new gas facilities, Member States shall ensure that the appropriate legal framework is in place by a specific deadline. Fast track processes like the ones foreseen by Regulation (EU) 347/2013[13] may be considered.

Furthermore, an obligation upon Member States that DSOs shall conduct an evaluation on the percentage of hydrogen that may be accepted by their networks without additional investments and a cost-benefit analysis on additional levels of hydrogen that may be accommodated with additional investments, may also be included in a future revision of the Directive.

e) Unbundling, involvement of DSOs in new-gas facilities and access conditions to new-gas facilities and storage

Directive 2009/73/EC requires legal and functional unbundling of distribution operators with over 100,000 customers. As a new-gas plant may be interpreted as a production facility, Article 26 of the Directive on unbundling of DSOs remains applicable, and at least legal unbundling is necessary unless the DSOs serves less than 100,000 customers. An extension of the rules concerning the role of gas DSOs in specific activities, as those adopted in Directive 2019/943/EU on electricity storage, may be examined in a proposal for a future amendment of the Gas Directive.

Clarity is also required for storage facilities and their regulation as Article 33 of the Gas Directive infers to storage connected at transmission level.

Concerning the ownership and operation of new-gas production facilities, we note that in general it is preferable for such activities to be developed under market conditions by gas producers/suppliers and not regulated monopolies. However, subject to further assessment, the involvement of DSOs could only be considered under specific market conditions and under strict requirements. The ownership and operation of production facilities by system operators could be developed under two models. One is that of a vertically integrated undertaking that owns and operates the facility and the produced gas. This for example can be the supply branch of a DSO with less than 100,000 customers and subject to accounting unbundling of the production activity to the remaining activities of the DSO. Another model could be that of a fully unbundled system operator, that owns and operates the facility but not the gas produced. In the second model the DSO shall offer a conversion service to independent third parties. Such service maybe the conversion of biogas to biomethane or electricity to gas (P2gas plants). In the latter business model, third party access rules shall be required.

In our view it is important in a future Gas Directive to define the activity (e.g. new-gas production or conversion as noted above and then to clarify who shall be allowed to undertake such activity (as a production or as a conversion service). For unbundled DSOs with over 100,000 customers, an exemption could be foreseen only under special market conditions e.g. to kick-start the market and for a limited period of time (analogy to the framework for electricity storage).

[13] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009

f) New role and tasks of the DSO in relation to new-gas facilities and the injection of new-gases

The energy transition calls for an extension of the role of the DSO from a simple transporter and operator of an existing network, to a more sophisticated network management and network development. The Directive includes no specific provisions related to obligations of the DSO towards new-gas, no provisions for the promotion of renewable sources or provisions for a structured TSO and DSO cooperation. In this context, we have formulated a set of specific recommendations in order to enhance the role of DSOs in facilitating the connection of new-gas facilities and the injection of gas at distribution level. Below we provide a summary of these recommendations on the evolving role of the DSO, readers are referred to Chapter 7 for further information.

The following additional tasks for gas DSOs are envisaged:

Gas quality: DSOs should be assigned specific responsibilities on gas quality monitoring and on taking actions when quality is not of the anticipated standards.

Connection requirements: DSOs should provide new-gas producers wishing to connect to the distribution network with sufficient information on connection rules, available capacity, costs, timing and quality of gas accepted. Rules shall not discriminate between new gas facilities and technologies employed.

Network Development: DSOs should prepare a network development plan. The plan should take into account at least forthcoming connections of new-gas facilities, needs for additional linepack or storage, potential for reverse flows to transmission and a long-term gas quality outlook for their distribution system. DSOs should cooperate with TSOs and also with electricity operators in case of P2Gas plants. Investment requests related to network development projects should be accompanied by a cost benefit analysis.

Network Operation: DSOs should develop specific rules for the operation of distribution systems taking into account new gas injection. DSOs should collect and publish gas quality data and pressure in their networks, provide NRAs information on all new gas plants connected to its system in terms of technology, production capacity, monthly production and connection date. Distribution system operators should cooperate with transmission system operators on topics related to daily operation.

Network operation, linepack and flexibility: Article 2(15) of Directive 2009/73/EC defines linepack as *"the storage of gas by compression in gas transmission and distribution systems, but not including facilities reserved for transmission system operators carrying out their functions"*. In simple terms, linepack is the ability of any gas grid to store gas. Every transmission or distribution pipe has a maximum pressure, under which it may be operated. This pressure depends on the material, diameter and thickness of the pipe. Operation pressure is typically lower than the maximum pressure and can vary during the day depending on the supply and demand balance thus providing different levels of short-term flexibility to the system.

There are a number of specificities related to pressure levels within distribution networks and thus to the availability of linepack. For example, typically, demand is low during the summer months and pressures in the network may also be low. Provided that this is indeed the case (e.g. pressure is low), as a P2Gas facility is expected to be receiving curtailed electricity for the production of gas throughout the year there may be a potential for some of the produced gas to be stored within pipelines, or in a storage facility at distribution level during the summer months. The same could be the case for biomethane production. Depending on the design of the balancing system and the technical capacity of the network there may be both a scope and an opportunity for the DSO to offer a commercial linepack flexibility service accompanied by a potential tariff for the service. On the other hand, new-gas injection may be refused in case the network pressure has reached the operational limits.

DSOs should report to NRAs and publish the average, minimum and maximum levels of linepack within the day for heating and the non-heating seasons. They should aim for an optimisation in the use of linepack so that the injection of new gases is not refused. Our review of the framework of selected Member States has shown that injection of new gases into networks is prioritised over other sources so as to ensure that these gases are accommodated. Lighter balancing obligations are imposed on new-gas producers in some cases. Practices identified in the countries reviewed can serve as a guidance to other Member States.

DSOs should be legally obliged to inform NRAs on cases where they have refused to accept the injection of new gases on one or more days due to existing high pressures in the network (i.e. lack of available capacity).

TSOs and DSOs cooperate daily regarding the injection of natural gas from the network of the former to the latter. It is anticipated that daily cooperation will be further intensified should injections to transmission be required.

g) Network planning at DSO level, coordination between TSOs/DSOs

Directive 2009/73/EC does not assign to gas DSOs an obligation for network planning. Interviewees to this study and our own research has confirmed that -at least in cases interviewed- gas DSOs already develop and submit to the regulator network development plants.

Connections of new gas facilities to distribution networks will be inherently related to some network expansions at mid or low pressure. Also, installation of gas quality measuring equipment at least at some distribution network branches will gradually become necessary and further upgrades may be needed to accommodate potentially variable new-gas injection patterns taking also into account the strong seasonality of demand in distribution.

Ultimately, high penetration levels of new-gases at distribution level may call for the installation of compressors to support reverse flows from distribution to transmission. Overall, such developments indicate a need for forward planning and further coordination between gas TSOs and DSOs.

The new electricity Directive 2019/943/EU introduced provisions (Article 32(3) to (5)) obliging electricity DSOs to publish, at least every two years, and submit to the regulatory authority a network development plan. We see such provisions as relevant to be considered in a potential future amendment of the Gas Directive. The gas DSO development plans should be subject to consultation and NRA approval and integrate the elements mentioned in paragraph (f) above under 'network development'.

DSOs and TSOs should coordinate for the preparation of their development plans and take into account the interactions between the electricity, gas and also heating, where district heating is established. In cases where network models are used, these should be common, including assumptions underpinning these network models.

Proposals for the installation of compressors that would enable reverse flows from distribution to transmission should be subject to cost benefit analysis. A base for cost sharing is already available from the cross-border cost allocation process of Regulation (EU) 347/2013. Overall, the allocation of capital and operational costs of compression will be an issue that has to be further assessed; it links to capacity booking arrangements in case of a potential physical reverse flow from distribution to transmission and to network tariff methodologies. In our view, if there is not a framework in place that allocates these costs to the users who are directly benefited from the reverse flows (e.g. the new-gas producers,) the costs will be ultimately allocated by the end-consumers of the two systems (distribution and transmission). Implementation of such solutions would require a purposely adapted cost-benefit analysis that can assess the benefits versus costs particularly if the cost of compression is to be borne as a whole or in part by end consumers. The f-factor methodology of Regulation (EU) 459/2017 (Art. 22) can provide some guidance in this direction.

h) Closed distribution systems and hydrogen networks

In a possible future framework for hydrogen, when and if hydrogen networks grow to serve multiple customers, then they should be subject to regulation as is the case with natural gas networks.

Energy intensive industries, which are currently also the owners and operators of closed hydrogen systems should be allowed to install new-gas facilities that may contribute to achieving sector and national decarbonisation targets. These facilities should be also recorded in a relevant national list of maintained by the NRAs as noted under paragraph b) above.

i) The role of the NRAs towards new-gases and DSOs, and incentives for innovation

Directive 2009/73/EC (Article 40(1.e)) already provides for the NRAs to facilitate the access to the network of new market entrants and production facilities of renewable gases. In a potential revision of the Gas Directive, the scope may be expanded to also include a specific reference to new gases.

NRAs should also approve the development plan of the DSO, monitor its implementation and supervise the cooperation between TSOs and DSOs as well as cross-sectoral cooperation between the operators of the gas and electricity sectors. We also see a role for NRAs in monitoring that the range of available alternative solutions that could lead to the reduction of reinforcement costs, as well as the reduction of gas losses, are taken into account. Most importantly, NRAs should monitor that DSOs fully take into account options for smart network management including, where possible, demand side management as means to avoid construction costs.

According to the Gas Directive (Article 40(f)), NRAs should ensure that transmission and distribution system operators are granted appropriate incentives, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities. Building on this provision, the scope of Article 41(8) should be expanded to include provisions for innovation and energy efficiency. The CEER has already offered further detailed recommendations regarding innovation in distribution networks, see Section 0 and references therein.

There may be also a scope for national regulators to consult with gas TSOs and DSOs on current operational cooperation mechanisms and on gaps and challenges they foresee in case of injection of new gases in distribution. Additional recommendations are offered in Section 7.

j) Participation of DSOs at EU institutional level

A scope towards the establishment of an EU DSO entity for gas has been identified by the participants to the 2019 CEER public Consultation and also by interviewees in this study. The EU DSO entity for gas can serve as a platform for discussions on topics related to new-gas standards, forecasting methods for quality and linepack, development of common methodologies for the evaluation of available capacity at distribution level, as well as issues related to network planning and operation towards a decarbonised gas future. The EU DSO can also cooperate with ENTSOG and the electricity EU DSO Entity at European level.

k) Tariff methodologies and tariffs

A number of high-level principles have been proposed to be included in a potential recommendation towards Member States. By analogy to the transmission service as defined in Regulation (EU) 2017/460 (EU NC TAR), it may be useful for Member States to include a definition of the distribution service i.e. the regulated service that is provided by the DSO within its distribution network for the purpose of transport. The distribution service should be distinct to other services provided by DSOs and tariffs for the distribution service should be distinguished from the tariffs of other services provided by the DSOs (regulated or non-regulated). For example, in a future new-gas dominated network DSOs may offer odourisation services to the new-gas producers or meter calibration services, maintenance of quality sensors owned by the new-gas producers, storage services etc. In a case where as analysed above a DSO is legally enabled to operate a new-gas facility offering a conversion service, it is clear that the cost of conversion services should be separate from distribution.

A transparent and cost reflective methodology for the evaluation of connection charges based also on a benchmarking analysis (or a unit investment cost reference) may serve towards increasing market confidence and remove any potential barriers to entry.

A transparent and cost reflective tariff methodology for firm (and interruptible) capacity reservation for the injection of new gases to distribution systems taking also into account seasonality factors and factors for non-yearly standard capacity products could be required in the future subject to increased new-gas penetration levels.

Obligations for periodic consultation with stakeholders and obligations for transparency related to the determination of the revenues of distribution system operators and to the parameters used as an input in the distribution tariff methodology should be introduced.

Third party access, capacity allocation and congestion management

DSOs should determine and publish available capacity at distribution level and report to NRAs refusals of connection or capacity allocation to new gas facilities and the grounds for such refusals.

No specific congestion management procedures are proposed at this stage; in the future, there may be a scope of considering interruptible contracts or injection management procedures.

A dedicated study on existing tools and mechanisms used by DSOs to establish the available capacity of their network would help to identify the different regimes across Member States and propose concrete measures. Such study could subsequently lead to a consultation document and a high-level recommendation on basic principles for the estimation of available capacity at distribution level.

Balancing

The operation of new-gas facilities is largely expected to be continuous, whereas demand at distribution level is highly seasonal. This may well be the case for biomethane plants. For P2gas plants operating profiles may be more complex also due to the volatility of electricity prices. Substantial daily variations can also be a key parameter for the operation of the system and the balancing requirements. Further discussion on balancing rules at distribution level should be pursued between DSOs, new-gas producers, TSOs and NRAs.

Transparency

It is recommended that regulators initiate procedures for the development of a transparency template for DSOs related to the connection of new gas facilities. Harmonisation of the template across Member States will be useful also for the purposes of subsequent monitoring by the Commission and ACER and for producers wishing to become active in a multinational environment. A task force in the CEER may undertake the coordination process.

An obligation for all entities that want to develop a new-gas facility to notify the regulator on what the output product will be, the output capacity, their location (stored in a GIS system), the technology used and on the anticipated schedule of implementation should be inserted in the legal framework at EU level. A standardised project fiche should be developed, possibly harmonised across Member States. Relevant information may also be included in the national development plants of transmission system operators.

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AGGM	Austrian Gas Grid Management AG
BRP	Balance Responsible Party
CEER	Council of the European Energy Regulators
CEP	Clean Energy Package
CHP	Combined Heat and Power
CCS	Carbon Capture and Storage
DSO	Distribution System Operator
FiT	Feed-in-Tariff
FSR	Florence School of Regulation
GOs	Guarantees of origin
GHG	Greenhouse gases
GME	Gestore dei Mercati Energetici, the Energy Market Operator of Italy
GTM	Gas Target Model
ICCT	Council on Clean Transportation
LSO	LNG System Operator
LTECV	Loi relative à la Transition Énergétique pour la Croissance Verte -
LULUCF	Land use, land-use change and forestry activities
MMR	Market Monitoring Report
NED	New Electricity Directive (Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU)
NER	New Electricity Regulation (Regulation (EU) 2019/943) of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity
NRA	National Regulatory Authority
PEM	Proton exchange membrane electrolysis
P2G	Power-to-Gas
RES	Renewable Energy Sources
SOEC	Solid oxide electrolysis cells
SSO	Storage System Operator
TEP	Third Energy Package
TYNDP	Ten Year Network Development Plan
TSO	Transmission System Operator
USS	Underground Sun Storage
VTP	Virtual Trading Point

Introduction

The EU is moving towards decarbonising its economy by 2050 in the order of 80-95%, with intermediate reduction targets of 40% and 60% by 2030 and 2040, respectively. These decarbonisation objectives are expected to be fulfilled by energy efficiency actions and further additions of renewable energy sources (RES) in the energy mix. Currently, natural gas plays a key role in the EU's energy consumption (23% of gross inland consumption in 2017[14]). However, its use is expected to decline sharply towards the achievement of the 2030 and 2050 milestones. Moreover, in the context of the European Green Deal, decarbonisation of the gas sector will have to be facilitated, including through the development of decarbonised gases based on a competitive decarbonised gas market, and by addressing the issue of energy-related methane emissions[15]. Decarbonisation of natural gas is crucial for it to continue being an important energy source in the longer term. According to various analyses and studies[16] potential contributions of the gas sector within the EU decarbonised long-term vision include the following:

- **Gas as seasonal storage of renewable energy.** The electricity system requires a constant balance between generation and demand and there is very little potential for storing electricity within networks. As the proportion of renewable energy supply to the electricity grid increases, the ability to match unscheduled intermittent supply with demand becomes increasingly problematic. Power-to-Gas technologies (P2G) which convert surplus renewable energy typically into hydrogen by rapid response electrolysis and its subsequent injection into existing gas transmission and distribution networks or intermediate storage can provide a good alternative. Storing energy in the form of gaseous fuels is an established practice particularly for seasonal and balancing needs.
- **Gas networks as means to reduce the need for expansions in the electricity network.** Electricity network expansion plans involve large investments and may face difficulties in realisation[17]. Adapting the electricity network to a further RES penetration and an increased electricity demand will require network expansions at substantially larger scales. A possible option would be to maximize the use of existing energy transport infrastructure, including of the gas infrastructure through for instance P2G technologies, instead of expanding the electricity network.
- **Renewable gas as a climate-neutral replacement of conventional natural gas**. Renewable gases are produced either by turning biomass into biomethane or as synthetic fuels. Use of renewable gas instead of conventional gas can contribute towards the EU decarbonisation targets.

Objective of the study

The study aims to

[14] Eurostat, (nrg_bal_s)
[15] Commission Communication COM(2019) 640 final *"The European Green Deal"*.
[16] Lebelhuber, C. and Steinmüller, H (2019) How and to which extent can the gas sector contribute to a climate-neutral European energy system? A qualitative approach, Energy, Sustainability and Society 9:23, and references therein.
[17] See indicatively van Melle T, Peters D, Cherkasky J et al. (2018) Gas for climate: how gas can help to achieve the Paris agreement target in an affordable way. https://www.gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Feb2018.pdf, Hecking H, Hintermayer M, Lencz D et al. (2017) Energiemarkt 2030 und 2050 – Der Beitrag von Gas- und Wärmeinfrastruktur zu einer effizienten CO2-Minderung. http://www.ewi.research-scenarios.de/cms/wpcontent/uploads/2017/11/ewi_ERS_Energiemarkt_2030_2050.pdf and Becker S, Rodriguez RA, Andresen GB et al (2014) Transmission grid extensions during the build-up of a fully renewable pan-European electricity supply. Energy 64:404–418. https://doi.org/10.1016/j.energy.2013.10.010, Nymoen|strategieberatung (2017) Green gas potential in ONTRAS network area. https://vng.de/sites/default/files/ontras_nymoen_strategieberatung_ptg-_potenziale_im_ontras-_netzgebiet.pdf.

- Evaluate the existing EU framework for the internal gas market as set mainly by Directive 2009/73/EC and identify barriers and gaps that may prevent the injection of new gases at distribution level.
- Assess the need for new rules and/or market arrangements at EU level concerning:
  - The operation and planning aspects of distribution networks including specific issues related to flexibility and storage;
  - Issues related to the injection of gases at distribution level;
  - Interoperability issues that may arise from the blending of gaseous fuels.
- Examine the role of gas Distribution System Operators (DSOs) and distribution networks under a new environment, shaped by the penetration of biogas, hydrogen and power to gas technologies.
- Assess the need and different options for formal representation of gas DSOs at EU level.

Further, the study aims to determine the need for further clarity in the role of the DSO for example the role of DSOs in measuring gas quality and the need for compliance to standards for the carbon footprint of the injected blend of gaseous fuels. Such standards may be related to the possible application of guarantees of origin, issued for the new gas injected to the distribution system, as a way of documenting the carbon footprint of the gas blend.

The study also looks into the relevance of the revised Electricity Directive provisions with regard to DSOs for the specific case of gas (i.e. storage, filling stations for gas vehicles).

Our work benefited largely from discussions with ACER, CEER and European associations active in the natural gas sector.

A set of recommendations on possible new measures are provided.

Methodology

The first part of the study comprises a review of the current status of EU markets regarding the penetration of new gases and a brief analysis of the European Long-Term Strategic Vision as presented by the Commission in its Communication COM(2018) 733 "*A Clean Planet for all: A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy*". Emphasis is placed on the scenarios quantified by the PRIMES model that project substantial penetration of new gases in distribution networks post 2030.

The second part of the study comprises a review of the national framework in selected EU Member States in relation to distribution. The following countries were considered: Austria, France, Germany, Italy and the Netherlands.

In the third part of the study we review the EU legal framework on the internal natural gas market. A starting point for this review is the Gas Target Model and the "Bridge to 2025 Conclusions Paper" prepared by the Agency for the Cooperation of Energy Regulators (ACER) in 2014 as well as the new "The Bridge Beyond 2025 Conclusions Paper" published jointly by ACER and the Council of the European Energy Regulators (CEER) on 19 November 2019. Other work of the CEER regarding the new role of distribution system operators was also considered. The purpose of this analysis is to shape the role of distribution system operators within energy transition.

Regarding the EU legal framework, focus in analysis is placed on an article-by-article review of Directive 2009/73/EC (hereinafter Gas Directive). Regulation (EU) 715/2009 targets mainly transmission with additional provisions for LNG terminals and storages.

Distribution networks are not in the scope of the Regulation, nevertheless, a review was carried out with a view to identify relevant best practices that could be extrapolated to distribution networks. The European network codes (Regulations (EU) 312/2014, 703/2015, 459/2017 and 460/2017) were also considered although these currently are also not applicable to distribution (or only applicable under conditions as is the case of Regulations 312/2014 and 703/2015). We also looked into the relevance of the revised Electricity Directive (Directive (EU) 2019/944) and Regulation (EU) 2019/943) and the results and recommendations included in other studies such as the 'sector coupling study'[18] and existing literature.

Our own review has been checked against and complemented by input from European institutions and stakeholders who were invited to express their views.

Report Structure

Following the introduction, the report consists of 7 Chapters:

- Chapter 2 sets the basic terminology used throughout this report and provides an overview of the current European market in relation to new gases.
- Chapter 3 looks into the EU Long Term Strategy to 2050 with emphasis on the penetration of new gases into the distribution network.
- Chapter 4 describes the evolving role of the DSO and distribution networks towards energy transition. Previous studies and actions are also reviewed, and a list of potential gaps and barriers is described.
- Chapter 5 looks into selected national case studies. Emphasis is on the national framework provisions in relation to the injection of new gases at distribution network.
- Chapter 6 is the core chapter of work and includes the assessment of the regulatory framework. The assessment and relevant recommendations offered in Chapter 7 built also on input provided by European associations consulted in the context of this study. Appendix 1 provide a by article review of Directive 2009/73/EC. Appendix 2 presents a review of Regulation (EU) 715/2009.
- Chapter 7 presents the conclusions and a summary of recommendations.

[18] Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU, https://ec.europa.eu/info/sites/info/files/frontier_-_potentials_of_sector_coupling_for_decarbonisation.pdf

New Gases and Renewable Gases

In this report we are using extensively the term "new gas". By "new gas" we refer to renewable gas and other gases that have a reduced carbon footprint in comparison to conventional (fossil) natural gas. Providing an exact definition of the various forms of gases included in the term of "new gases" used herein is beyond the scope of the project. However, we note to readers that a relevant debate has already started during the 32nd Madrid Forum of June 2019 where a distinction was proposed between renewable, decarbonised and low-carbon gases. Figure 1 shows by way of example, the proposal of a certain segment of the industry (CEDEC) towards the definition of new gases. Different gases can have different physical and chemical properties that need to be taken into account not only towards meeting the EU decarbonisation targets but also for ensuring *the operation, maintenance and development under economic conditions of secure, reliable and efficient transmission, storage and distribution networks* (Articles 13 and 25 of the Gas Directive). It is clear that the legal framework should strike a proper balance between not inhibiting the injection of new gases into existing networks on one hand and not creating undue barriers to the common energy market and overall EU internal market. We discuss this topic in more detail in the forthcoming Sections.

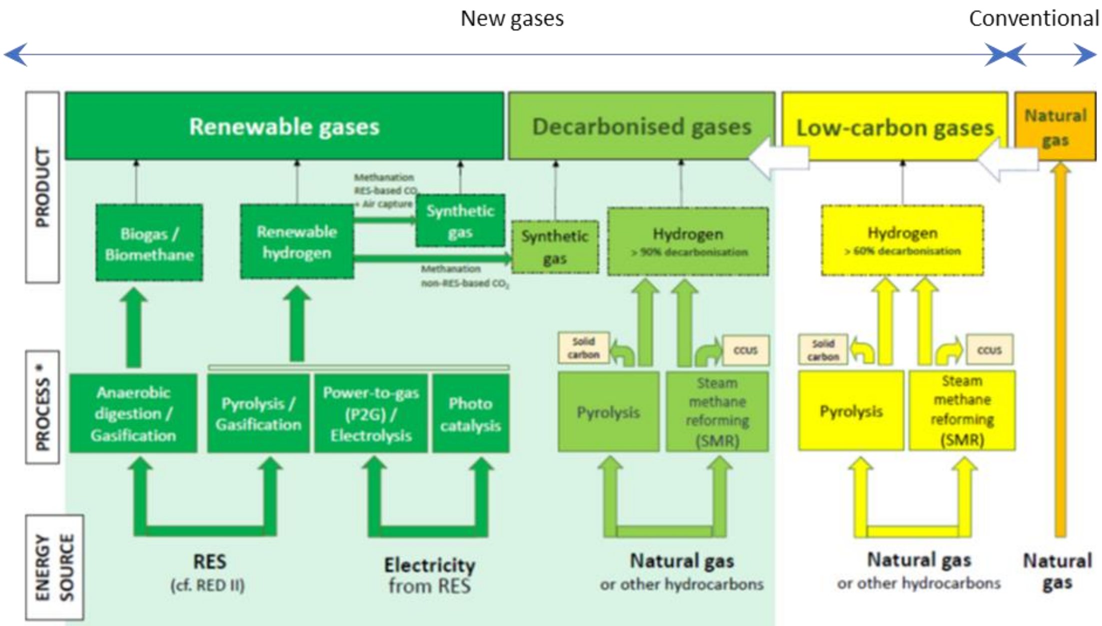

Figure 1 New gases and conventional natural gas[19]

A background on the terminology of "New Gases"

The existing legal and regulatory framework (e.g. the Gas Directive) targets the internal market in natural gas. The Directive does not define what is meant by the term "natural gas". It is generally acknowledged that by natural gas, reference is made to a "*colourless highly flammable gaseous hydrocarbon consisting primarily of methane and ethane. [..]often found dissolved in oil […] reservoirs and as a cap above the oil. Such natural gas is known as associated gas; [..] or wet gas. There are also reservoirs that contain only gas and no oil. This gas is termed non-associated gas [..] or dry gas."*[20]. Thus, conventional natural gas (or fossil gas), which has been a focus of European energy

[19] Source CEDEC, 32nd Madrid Forum, the disclaimer added by CEDEC is copied here "This overview is based on existing processes and known technologies and evidently does not preclude new technological developments".
[20] See for example https://www.britannica.com/science/natural-gas

regulation for more than two decades, is a gaseous substance extracted from earth's underground.

Further, the Gas Directive is also applicable to biogas or other types of gas in so far as such gases can technically and safely be injected, and transported through, the natural gas system.[21] Thus, the Gas Directive is also applicable to the so-called renewable gases or new gases as defined above. A gas source is renewable if it is naturally regenerating on a human timescale. Renewable energy includes wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas[22]. Regeneration is an important component of long-term sustainability, as it ensures that these resources can be used to meet the needs of the present without compromising future demands. However, not all renewable energy sources generate the same carbon savings. Other processes and technologies (for example pyrolysis or steam reforming of fossil fuels) can also achieve GHG reductions; however, the resulting gas is non-renewable. Overall, the feedstock used to produce a specific gas type typically determines that gas' cradle-to-grave GHG emissions.

In a recent paper[23], also debated at the 32nd Madrid Forum in June 2019 and in an online session organised by the Florence School of Regulation (FSR), the International Council on Clean Transportation (ICCT), offered a set of definitions that may be used as a guidance towards understanding differences between renewable and other types of new gases. These definitions are summarised in Box 1. Box 2 presents as an additional example, ICCT terminology for non-renewable new gases. ICCT terminology differs from the respective terminology of the gas industry (Figure 1) and is also shown here indicatively as an example of the type of gases that may be included in the general term of a "new gas" to be adopted herein.

Box 1 - Renewable gases

- Renewable gas: Biogas, renewable methane and renewable hydrogen.
- Biogas: Gaseous fuels produced from biomass, as defined in point 24 of Article 2 of Directive (EU) 2018/2001, including energy-carrying gas that is primarily methane and mixtures that are partially methane produced from biomass feedstocks through anaerobic digestion, gasification, or other processes.
- Renewable hydrogen: Gas containing primarily hydrogen produced from biomass, as defined in point 24 of Article 2 of Directive (EU) 2018/2001, or from a process using renewable energy as defined in point 1 of Article 2 of Directive (EU) 2018/2001 as the sole energy-carrying input.
- Renewable methane: Gas containing primarily methane produced from biomass, as defined in point 24 of Article 2 of Directive (EU) 2018/2001, or from a process using renewable energy as defined in point 1 of Article 2 of Directive (EU) 2018/2001 as the sole energy-carrying input, including methane produced from renewable electricity and waste or ambient CO_2.

[21] Art. 1(2) of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
[22] Article 2(1) of Directive 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.
[23] Searle, S and Pavlenko, N. Gas definitions for the European Union, The International Council on Clean Transportation, 25 September 2019, https://theicct.org/publications/gas-definitions-european-union

Box 2 - Non-renewable gases classified in terms of their GHG intensity

- High-GHG: Gases with a life-cycle GHG intensity of 30% or higher than business-as-usual natural gas can be classified as high-GHG. This includes natural gas and hydrogen produced from natural gas without effective carbon capture and storage (CCS), and synthetic gases produced from fossil-derived electricity. Some renewable gas or biomethane pathways can also be high-GHG if they cause high land-use change or other indirect emissions. This category of gas likely needs to be phased out in the near future in order to meet Europe's climate targets.
- Low-GHG: Gases that reduce lifecycle GHG emissions by a substantial degree compared to business-as-usual natural gas can be classified as low-GHG. For example, the Renewable Energy Directive 2018/2001 requires renewable power to- methane to reduce GHG emissions by 70% compared to fossil fuels. Low-GHG energy sources meaningfully reduce overall climate impacts compared to conventional fossil fuels. When assessing lifecycle GHG emissions, it is important to include direct and indirect emissions from land-use change, displacement of feedstocks from other uses, and electricity grid impacts in the calculation of lifecycle GHG performance.
- GHG-neutral: Gases with zero net GHG emissions can be classified as GHG-neutral. GHG-neutral energy sources have either no impact or a beneficial impact on climate change compared to not using the energy source at all. This includes pathways with negative GHG emissions on a life-cycle basis. For example, if avoided methane emissions upstream more than counteract processing & combustion emissions, the gas could be classified as GHG-neutral.

New gases can also contain a percentage of hydrogen, which may vary from 0 to 100%. Depending on whether hydrogen is produced from renewable sources (e.g. electrolysis by use of RES energy) or through fossil fuel pyrolysis or methane steam reforming, Figure 1, its "cradle-to-grave" carbon footprint may differ.

In the remaining of this Chapter, we provide a snapshot of the current status of penetration of new gases in Europe. The review has been prepared by looking into different types of new gases as broadly defined above.

The current European Market of "new-gases"

Information reported in this Section is sourced from the comprehensive work of Gas Infrastructure Europe (GIE)[24], the European Biogas Association[25] and a combination of several sources available online.

Biomethane plants

The end of 2018 saw a total of 18,202 biogas installations, a Europe-wide installed electric capacity (IEC) of 11,082 MW, and 63,511 GWh of biogas produced[26]. These numbers should be compared to relevant data for 2017 with17,783 biogas plants and a total installed electric capacity of 10,532 MW. Total generated electricity from biogas in 2017 amounted to 65,179 GWh (2% of total electricity production[27]) and an average annual growth rate of 5%. Biomethane production is also increasing reaching 19 TWh or 1.94 bcm in 2017 and 2.28 bcm in 2018 from 610 plants. The value of biomethane

[24] https://gie.eu/download/maps/2018/GIE_BIO_2018_A0_1189x841.pdf
[25] https://www.europeanbiogas.eu/wp-content/uploads/2019/05/EBA_Statistical-Report-2018_AbrigedPublic_web.pdf
[26] EBA Statistical report 2019
[27] Eurostat (2017), Table nrg_cb_e

production quoted above corresponds to just 0.5% of the total gross available energy of natural gas[28] in EU 28 as reported by Eurostat for 2017.

EBA reports on 15 European countries with biomethane production, namely AT, CH, DE, DK, ES, FI, FR, HU, IS, IT, LU, NL, NO, SE, and the UK. Three more countries – Belgium, Estonia and Ireland – reported their first biomethane producing plants in 2018.

According to 2018 data, Germany is host to the largest number of biomethane plants in Europe (208 in 2018, producing 9.8 TWh of biomethane; however only a fraction of 0.4 TWh is injected to the network[29]). To better comprehend magnitude of this value, note that gas consumption in the domestic sector in Germany was 657 TWh in 2017[30]. Nevertheless, the number of biomethane facilities is increasing; in 2019, Dena, the German Energy Agency, reports 213 plants with an additional 10 under construction[31]. For more information on Germany readers are referred to Section 0.

France is also experiencing a substantial growth in biomethane facilities. In 2015 there were just 17 facilities in operation of cumulative production capacity of just 0.3 TWh/year. In 2019, the number of facilities increased to 107 and production capacity has increased by a factor of 6 to 1.8 TWh[32]. Out of these, 90 facilities producing 1.3 TWh of gas are connected to the distribution networks of GRDF (the largest natural gas distribution operator in France owing 96% of all networks). Five more facilities producing 0.1 TWh are connected to the distribution networks of 3 smaller operators (Veolia-Eau, R-GDS and Régaz). The remaining production facilities are connected to the transmission network of the two transmission operators (GRTgaz and Teréga).

The next major biomethane producer is the UK, where EBA reports on 92 plants for 2017. From information available on the press, biomethane production is estimated to reach 2.5 TWh in 2019 (0.6% of total gas available for final consumption).

Hydrogen production

The IEA Hydrogen database[33] reports on 184 facilities that became operational in the period 2000 to 2019. in Europe (including Norway, Switzerland and Iceland) as a result of power-to-X technologies. They produce hydrogen from various forms of electrolysis (Alkaline electrolysis, PEM[34], SOEC[35], other). Total capacity of the facilities reported is of the order of 0.75 bcma (2.6 TWh)[36]. However, only 86 plants of capacity of 0.68 bcma remain operational. From the projects currently in operation, less than 0.2 bcma (62 GWh) are injected into a hydrogen or natural gas grid, Figure 2.

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[28] Eurostat (2017), Table nrg_bal_c
[29] DENA, https://www.dena.de/fileadmin/dena/Dokumente/Veranstaltungen/EBC_2018/Praesentationen/11_Matthias_Edel_dena.pdf, and Eurostat (2017)
[30] Eurostat (2017) Table nrg_bal_c,
[31] dena-ANALYSE: Branchenbarometer Biomethan 2019, https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2019/dena-Analyse_Branchenbarometer_Biomethan_2019.pdf
[32] OPEN DATA, Reseaux Energies, Biomethane injection points in France, https://opendata.reseaux-energies.fr/explore/dataset/points-dinjection-de-biomethane-en-france/information/?disjunctive.site&disjunctive.departement&disjunctive.region&disjunctive.type_de_reseau&disjunctive.grx_demandeur
[33] IEA Hydrogen Database 2019, https://www.iea.org/media/publications/hydrogen/IEA-Hydrogen-Project-Database.xlsx
[34] PEM: Proton exchange membrane electrolysis
[35] SOEC Solid oxide electrolysis cells
[36] Own estimate based on IEA total reported value of 3.5 mil Nm3/h, for a gross calorific value of 3.54 kW/Nm3 (http://www.h2data.de/)and 350 days per year of operation of the facilities.

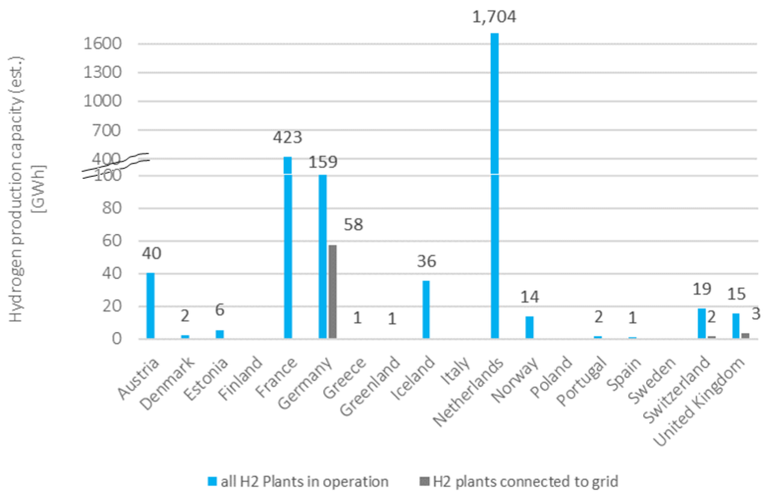

Figure 2 H_2-plants in operation (2019)[37]

Twenty-one (21) projects of total capacity of 27 bcma (circa 96 TWh) are expected to become operational in the period 2020-2028, Figure 3. Thirteen more projects are included in the IEA database without a fixed starting date. These amount to a further 2 bcma (circa 7 TWh). If these projects are realised, hydrogen production will increase by at least a factor of 10. Almost all hydrogen to be produced in France and the UK will be injected into transmission or distribution natural gas networks or into hydrogen dedicated networks. For Germany and the Netherlands, the values of grid injected hydrogen are substantially less in the period 2020-2028. Two new projects, METHYCENTRE in France and Hybridge in Germany, are due to become operational in 2020 and 2023 are expected to produce synthetic methane also to be injected into the grid.

The country specific analysis undertaken as part of this study and presented in Chapter 0 provides further information on selected hydrogen projects in the countries reviewed.

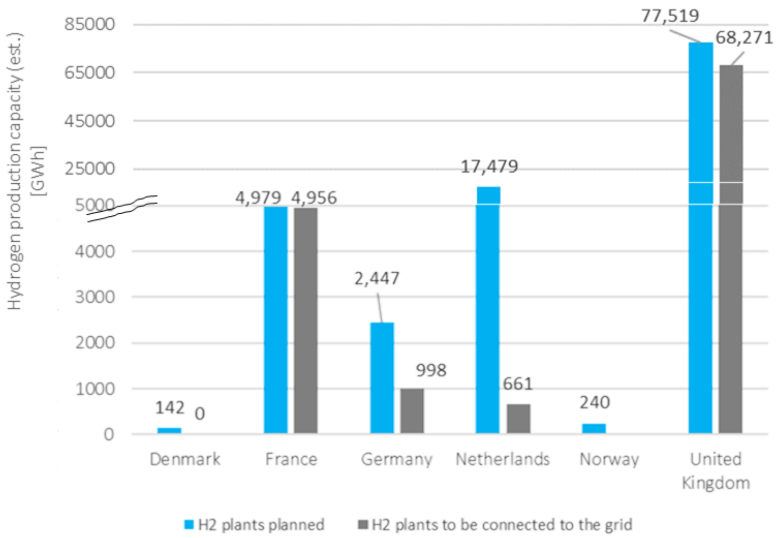

Figure 3 H2 plants due to become operational in the period 2020-2028[38]

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[37] IEA Hydrogen Database.
[38] IEA Hydrogen Database. Announced plants with non-specified start dates are also included in the figure. Plants announced that they will be producing synthetic methane to be injected into the grid are also included in figure.

The European Long-Term Strategic Vision to 2050 and Beyond

This Chapter looks into the in-depth analysis published by the Commission on 28 November 2018[39] in support to its Communication COM(2018) 733 "A Clean Planet for all: A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy".

The aim of the long-term strategy is to confirm Europe's commitment to lead global climate action. It sets the direction of travel of EU climate and energy policy and frames what the EU considers as its long-term contribution to achieving the Paris Agreement temperature objectives.

The starting point is a common baseline reflecting the 2030 energy and climate policies and targets as recently agreed through the adoption of the Clean Energy Package[40] including the Regulation on Governance of the Energy Union and Climate Action[41] and additional legal framework such as the revised directive on the emissions trading system[42]. Overall the baseline takes into account the reformed EU emissions trading system, national greenhouse gas emission reduction targets, legislation to maintain the EU land and forests sink, the agreed 2030 targets on energy efficiency and renewable energy, as well as the proposed legislation to improve the CO_2 efficiency of cars and trucks. These policies and targets are projected to reach reductions of greenhouse gas emissions of around -45% by 2030 and around -60% by 2050. These reductions however are not sufficient for the EU to contribute to the long-term temperature goals set in Paris Agreement.

To achieve the Paris goals, additional actions would be required. These are investigated through an analysis of eight alternative pathways – eight scenarios that build upon no regret policies such as strong usage of renewable energy and energy efficiency. The scenarios cover the potential range of reductions needed in the EU to contribute to the Paris Agreement's temperature objectives of between 2°C and 1.5°C temperature change. This temperature range is translated into a reduction for the EU in 2050 (compared to 1990) of between 80% (excluding LULUCF) and 100% (i.e. achieving net zero GHG emissions) of greenhouse gas emissions (GHG).

The Commission's analysis was complemented by modelling, mainly using the PRIMES-GAINS-GLOBIOM[43] model suite. The PRIMES-GAINS-GLOBIOM model suite includes all sectors and GHG gases, covering not only CO2 emissions related to energy combustion, but also CO2 process emissions (emissions due to a chemical reaction), absorptions and emissions of CO2 of the land use sectors (forestry and agriculture mainly), non-CO2 emissions of all sectors with largest sectors being the agriculture, energy, waste and industrial sectors (including F-gas applications).

The scenarios that were examined in the context of the EU Long Term are the following:

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[39] https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf
[40] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources, Directive 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency, Directive.
[41] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, amending Regulations (EC) No 663/2009 and (EC) No 715/2009 of the European Parliament and of the Council, Directives 94/22/EC, 98/70/EC, 2009/31/EC, 2009/73/EC, 2010/31/EU, 2012/27/EU and 2013/30/EU of the European Parliament and of the Council, Council Directives 2009/119/EC and (EU) 2015/652 and repealing Regulation (EU) No 525/2013 of the European Parliament and of the Council
[42] Directive (EU) 2018/410 of the European Parliament and of the Council of 14 March 2018 amending Directive 2003/87/EC to enhance cost-effective emission reductions and low-carbon investments, and Decision (EU) 2015/1814
[43] https://ec.europa.eu/clima/policies/strategies/analysis/models_en#Models

Energy Efficiency (EE) achieves energy savings close to the identified maximum potential, through policies promoting near zero energy buildings, for both new and renovated, as well as stringent technology standards for all appliances, equipment and vehicles.

Circular Economy (CIRC) restructures industry to optimise resource efficiency, increase material and equipment recycling rates and reduce thereof primary production of energy-intensive metals, chemicals and non-metallic minerals. The scenario also introduces behavioural and restructuring changes in the transport sector and emphasises the role of bioenergy (liquids and gaseous).

Electrification (ELEC): Electrification is a "no-regret" option, but maximum electrification is an ambitious and uncertain strategy. The scenario includes electricity as (almost) the single energy vector in all sectors in the long-term, including high-temperature industrial processes and most transport modes. Biofuels are present as a complement of electricity, but only in sectors where full electrification is not technically feasible with currently known technologies, such as in aviation and maritime.

Hydrogen (H2): The strategy assumes that hydrogen production and distribution infrastructure develop, thus allowing hydrogen to become a widely used energy commodity, covering all end-uses including transport and high-temperature industrial uses. Hydrogen could provide a versatile electricity storage service with daily up to seasonal storage cycles. Hydrogen is assumed to become the main distributed gas after extensive overhaul of the pipeline system and gas storage facilities.

Power-to-X (P2X): The current infrastructure and the paradigm of using and distributing energy commodities are maintained. The origin of the hydrocarbon molecules is non-fossil to ensure carbon neutrality. It is meaningful that the production of synthetic methane and liquid fuels uses hydrogen from carbon-neutral electricity and carbon dioxide captured in the ambient air or from biogenic sources.

The scenarios above address the well below 2°C ambition, aiming for GHG emissions reduction levels in 2050 of around 80% compared to 1990.

Three additional scenarios (COMBO, 1.5 TECH and 1.5LIFE) assume a combination of elements, for both energy demand and supply sectors, from the five abovementioned scenarios. The last two scenarios 1.5 TECH (with more focus on the energy supply sectors) and 1.5LIFE (with more focus on energy demand) were designed to explore the feasibility of the climate neutrality objective and constitute the "1.5°C-GHG" pathways.

For the purpose of this work we analyse below scenarios Hydrogen (H2), Power-to-X (P2X) and the 3 additional scenarios (COMBO, 1.5 TECH and 1.5LIFE). A more detailed description by scenario is provided below.

- The **H2 scenario** foresees high deployment of hydrogen in final uses in transport, buildings and industry, <u>benefiting from possible applications that are currently known</u>. This is facilitated by properly adjusting the gas distribution grid and heating equipment to accommodate high shares of hydrogen (allowing for a mix up to 50% in gas distribution in 2050 and 70% in 2070). Dedicated infrastructure is assumed to facilitate high shares of hydrogen in transport. Additionally, the blending of biogas quantities in the gas distribution grid, further reduces the quantity of fossil-based natural gas, therefore, providing low carbon distributed gas to the final consumers (for heating uses in buildings, industry and for heat production). Moreover, the scenario assumes direct use of hydrogen in high-temperature industrial furnaces, produced locally via electrolysers. In transport, some competition between hydrogen and electricity takes place for cars and vans, the main difference coming from vehicles that cannot run on batteries, such as long mileage cars, coaches and trucks. The hydrogen refuelling infrastructure, assumed to be deployed by 2050 in this scenario, facilitates the uptake of hydrogen for these uses.

- The **P2X scenario** is similar to the H2 scenario, but hydrogen becomes mainly an intermediate feedstock for the production of e-fuels (e-gas and e-liquids). E-fuels have the advantage of having the (almost) same chemical properties as their fossil counterparts. However, their production is energy intensive, as a further transformation step is required, after the hydrogen is produced via the electrolysers. Moreover, carbon feedstocks are required, their future availability at the required quantities being quite uncertain. The distributed gas in this scenario constitutes of a combination of e-gas and biogas to provide end-users with a distributed gas of identical quality as today, but with low remaining emissions. For the transport sector, the use of e-liquids would allow for the reduction of emissions in transport modes where emissions reduction are costly, in particular where electrification is difficult or where developing an alternative technology/infrastructure (fuel cells and hydrogen infrastructure) requires significant changes. Towards 2050, hydrogen is produced by electrolysis, e-gas in methanation plants and e-liquids via various chemical routes, notably the methanol route and the Fischer-Tropsch process. To be carbon neutral, both e-gas and e-fuel production use CO2 captured from the ambient air and biomass-using power plants. The production of e-fuels implies that this scenario sees an even higher electricity demand than the H2 scenario, the highest one among all scenarios, as the production of e-fuels requires a further transformation step after the production of hydrogen. The production of e-fuels, however, also provides medium to long-term storage services for the additional electricity generation requirements, which are mainly satisfied through additional variable renewable energy investments.
- **COMBO** combines effective solutions for each sector/mode from the scenarios ELEC, H2, P2X and EE COMBO does not push for extreme deployment of specific technologies or actions. It neither focuses on the development and deployment of specific negative emission technologies by 2050, nor promotes actions incentivising the uptake of CO2 in our land sink. It does not include consumer choice changes. The only pathway that was not included in the COMBO scenario is the one of circular economy.
- **1.5TECH** is similar to COMBO but with more ambitious decarbonisation. It assumes limited additional incentives to improve the land use sink. It increases CCS aiming to lower more the remaining emissions and applies more use of e-gases and fuels based on air captured or biogenic CO2 to reduce remaining emissions. It applies negative emission technologies via biomass coupled with CCS and the storage of biogenic CO2 in material.
- **1.5LIFE** is similar to COMBO but with more ambitious decarbonisation. The scenario addresses emission abatement by focusing more on demand-side measures, as well as increased take up by the land-use sink. It assumes that consumers make different choices in an effort to avoid certain carbon-intensive activities and develop more sustainable lifestyles. Towards 2050, the demand for air transport is reduced relative to the Baseline as significant shift takes place to rail and significantly increased modal shift takes place towards lower emission transport modes for both passenger and freight transport. Also, there is an assumption that shifts in food preferences by consumers continues towards less animal-based products. Due to a behaviour focusing on rational use of energy, demand for heating and cooling is lower compared to other scenarios. Increased modal shift takes place towards lower emission transport modes for both passenger and freight transport. The latter is also linked to improved city planning, improved logistics, integrating sharing economy and connected, cooperative and automated mobility, and making full use of digitalisation, automation and mobility as a service (see Section 4.4.2 for resulting impacts on transport demand). This scenario also includes the drivers and assumptions of the circular economy scenario.

Scenarios Hydrogen (H2), Power-to-X (P2X) and COMBO have a 2050 GHG reduction target of -80% in 2050 (in comparison to 1990 levels). The 1.5TECH and 1.5LIFE scenarios aim for climate neutrality. For the sake of clarity, we underline that the term "climate-neutrality" is equivalent to the net phase-out of all GHG emissions. GHG-neutrality has the same meaning, although it is more specific than climate-neutrality. "Carbon neutrality" is a similar concept but only for CO2 emissions[44].

Figure 4 - Changes in sectoral final energy consumption (% change vs 2005). Note that services also includes agriculture[45].

Main observations

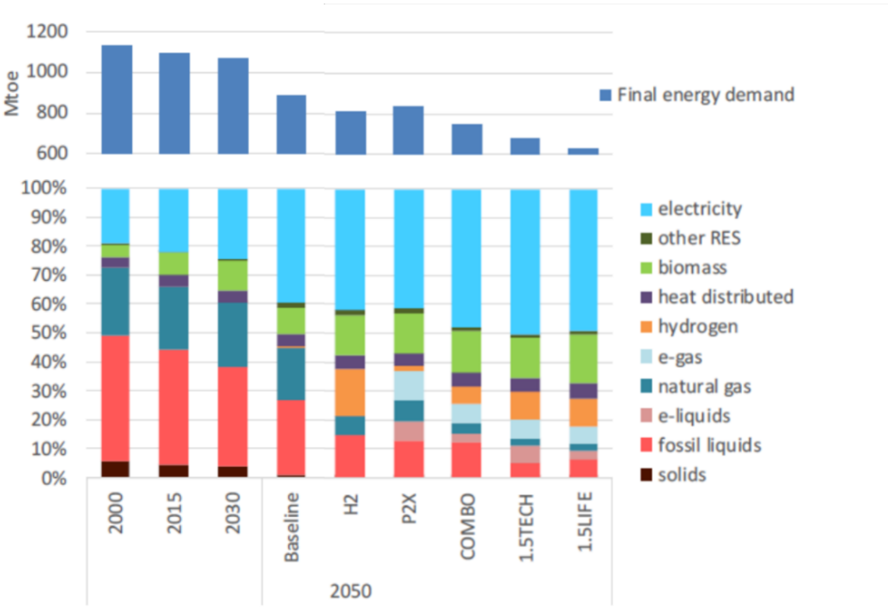
Before we analyse specific projections regarding the penetration of new gases in the distribution network it is useful to look into the high-level elements of the evolution of the energy system for the 5 scenarios presented here.

All scenarios incorporate a strong energy efficiency component. Even in the Baseline, the final energy consumption is substantially reduced. The 2030 target on energy efficiency (32.5% reduction compared to 2007 Baseline) translates into a 20% reduction in final energy consumption compared to 2005 levels. Final energy consumption is at -26% in comparison to 2005 levels for the baseline in 2050. For the Scenarios H2 and P2X, the respective reductions in final energy consumption are of the order of -30% compared to 2005,

Figure 4. Reductions in final energy consumption for the residential sector (which is relevant to the injection of new gases in distribution networks) are as much as -40%.

[44] See for example Capros, P., Zazias, G. Evangelopoulou, S, Kannavou,M, Fotiou, T, Siskos, P., De Vita, A., Sakellaris, K. (2019) Energy-system modelling of the EU strategy towards climate-neutrality, Energy Policy 134 (2019) and references therein.

[45] All figures in this section have been sourced from the In-Depth Analysis in Support of the Commission Communication COM(2018) 773 A Clean Planet for all A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy



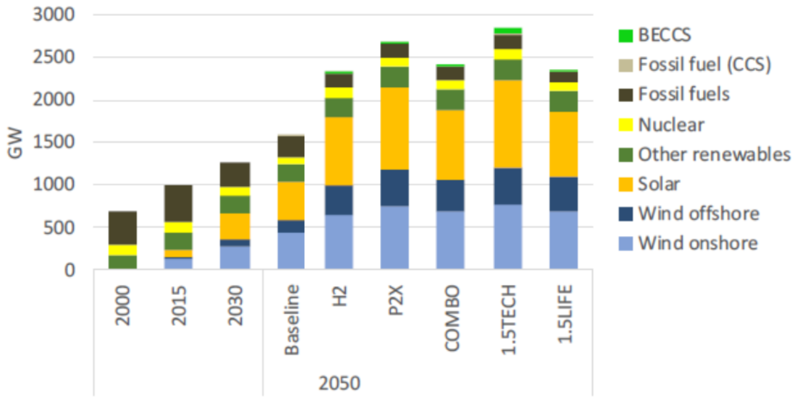
Source: Eurostat (2000, 2015), PRIMES.

Figure 5 - Share of energy carriers in final energy consumption

Figure 6 - Changes in final electricity consumption in 2050 compared to 2015

Figure 5 shows that penetration of hydrogen in the H2 scenario reaches a maximum of circa 20%. In the remaining scenarios, the combination of hydrogen and other electricity produced gases and liquids (hereinafter e-gases and e-liquids) is in the range of 10-15% of final consumption.

All decarbonisation scenarios confirm that electricity will play a central role in energy transition, not only as an energy vector enabling the decarbonisation of final energy demand but also as a feedstock producing carbon-neutral synthetic fuels. For the scenarios we present herein, electricity consumption increases in the range from 30% (1.5LIFE) to 50% (COMBO). Increased electricity demand is attributed to the increased electrification of all sectors, most notably the residential and services.



Source: Eurostat (2000, 2015), PRIMES.

Figure 7 Power generation capacity[46].

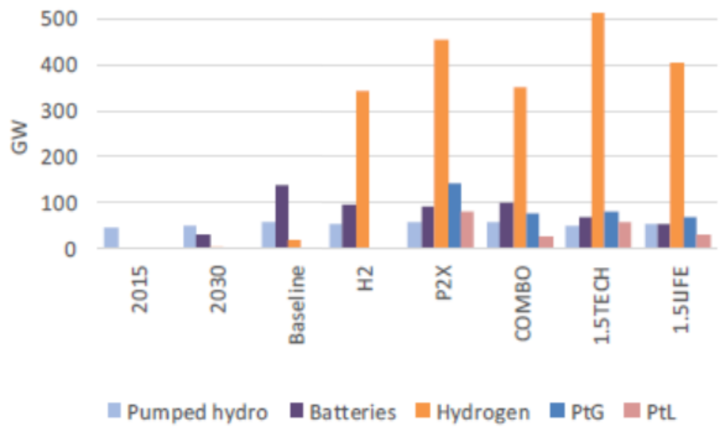


Figure 8 - Electricity storage and new fuel production capacities (2050)

Fossil fuels, which represented 43% of the electricity production in 2015, become marginal contributors in the decarbonised power system. In fact, by 2050, natural gas is the only fossil fuel left in the mix, with a share falling from 16% in 2015 to 12% in 2030 and to 5% in 2050 (P2X). Biogas consumption in the electricity system develops between 22 and 45 Mtoe in 2050 in all scenarios. The overall net installed electricity capacities reach 2700 GW (P2X) or as much as 2800 GW (1.5TECH) in 2050. These levels are almost double the corresponding levels of 2015 (985 GW). Increased capacity is required not only to meet increased electricity demand but also due to the reduced operating times of intermitted RES sources in comparison to conventional production.

The development of e-fuels also creates a new need for electricity supply. However, hydrogen is only marginally used in power generation (some 15 Mtoe in the H2 scenario). The remaining of electricity produced fuel (e-gas or e-liquids) are not used in electricity generation, Figure 7.

[46] BECCS stands for Biomass for Energy with Carbon Capture and Storage

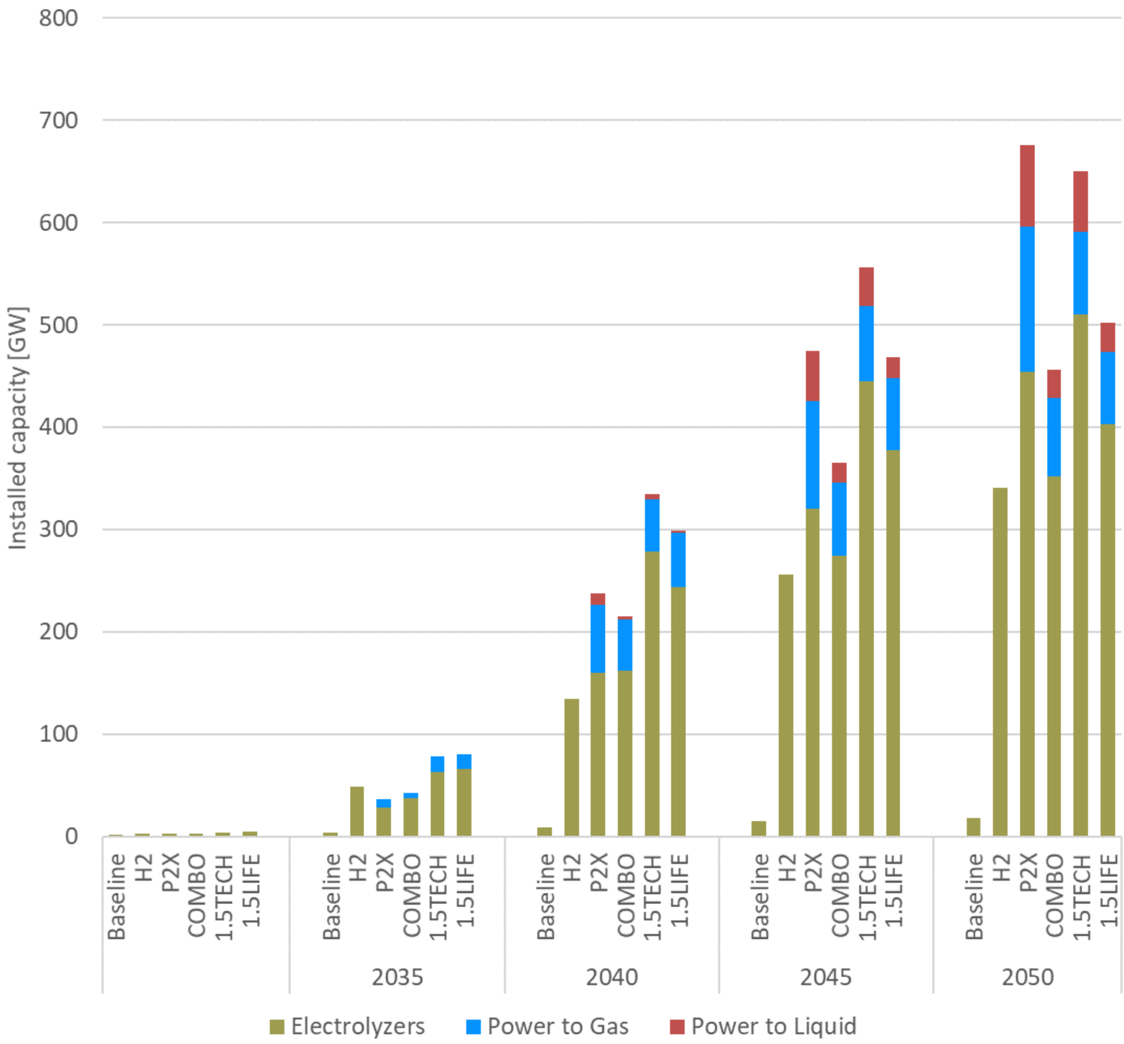


Figure 9 - Installed capacity by type of production plant (source PRIMES)

Figure 8 shows that electricity storage, through electricity conversion into hydrogen, e-gases and e-liquids, calls for the installation of cumulative capacity of hydrogen and other power to X production facilities of about 700 GW in 2050. Installation of hydrogen production facilities of a significant cumulative size (e.g. in the range from 1 to 5 GW) begins in 2030. Capacity is increased by as much as a factor of 20 in 2035 (H2 scenario). Installation of additional new capacity continues until 2050, **Error! Reference source not found.**. Installed capacity of power-to-gas plants exceeds 1 GW only after 2035 (for the P2X, COMBO and 1.5TECH and LIFE scenarios). In 2040, installed capacity increases by factors from 3 to 7 depending on the scenario. Additional P2Xs are installed in 2045 and 2050. Power-to-liquid plants attain a substantial size of over 1 GW only in 2040.

Sectoral projections of natural gas and new gases and the relevance for distribution networks

Consumption of conventional (fossil) natural gas (excluding non-energy use) is severely reduced by 2050 in all scenarios, Figure 10. The reduction in gas consumption impacts the residential and services sectors serviced by distribution networks. Figure 11 shows a moderate decreasing trend in natural gas consumption of the order of 10-12% in the period post 2020 and till 2025 (in comparison to 2020 levels). This is followed by an additional substantial reduction of -15% in 2030 (in comparison to 2025 levels). From 2035 onwards, values vary depending on the scenario. The natural gas demand of residential and services sectors (mainly for heating) is met in part by electricity and in part by substitution of natural gas by biomass, hydrogen and e-gases post 2030. The scenarios examined reveal negligible substitution of natural gas by new gases in 2030, Figure 13. In 2035 the penetration of new gases in distribution is projected of the order of 10%. In 2040, 12% of natural gas is substituted by hydrogen in the H2 scenario and as much as 50% of conventional natural gas is replaced by GHG free gas and biogas in the remaining scenarios. In 2045 and 2050, new gases exceed the amount of fossil natural gas in the network.

Subject to additional enabling conditions (e.g. substantial financial support to one or more technologies producing new gases, faster technological maturity than one foreseen in the scenarios examined in the context of the EU Long Term Strategy), penetration to distribution can occur earlier in time. It is also possible that certain new gases may be preferred over others.

Overall, there seem to be reasonable grounds to consider, and prepare, for a potential substantial penetration of new gases in distribution.

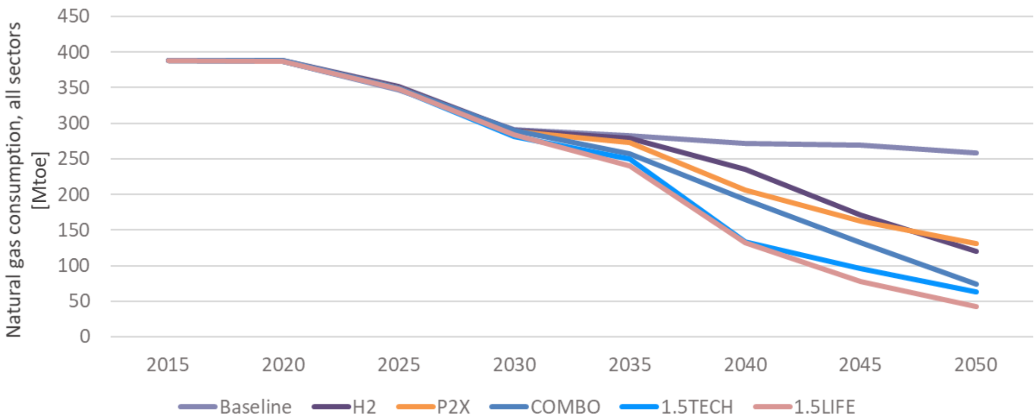


Figure 10 Natural gas consumption (fossil), all sectors (source PRIMES)

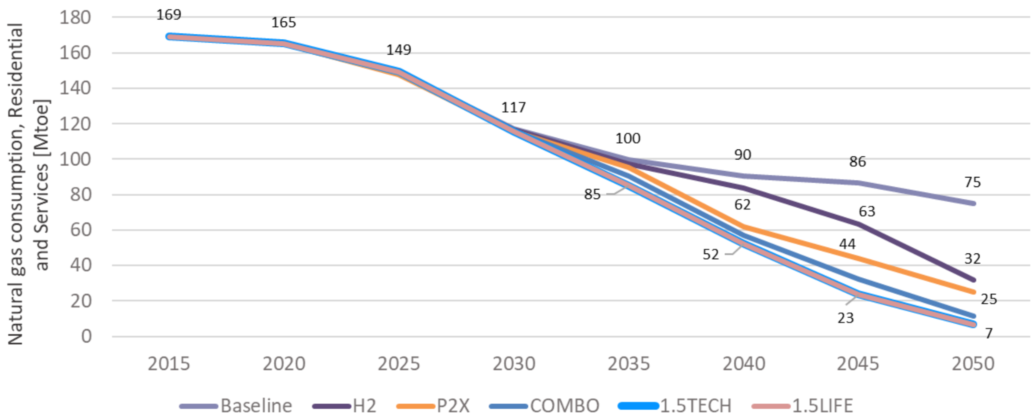


Figure 11 Natural gas consumption (fossil) in the domestic and service sector, values also include agriculture (source PRIMES)

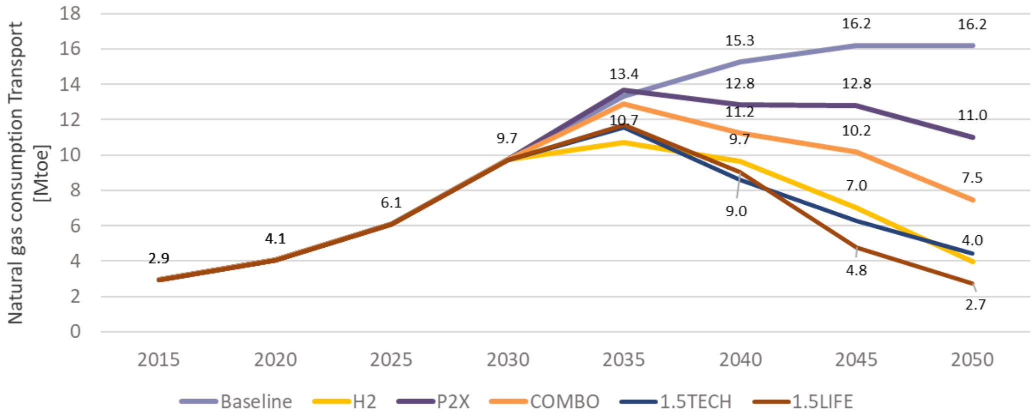
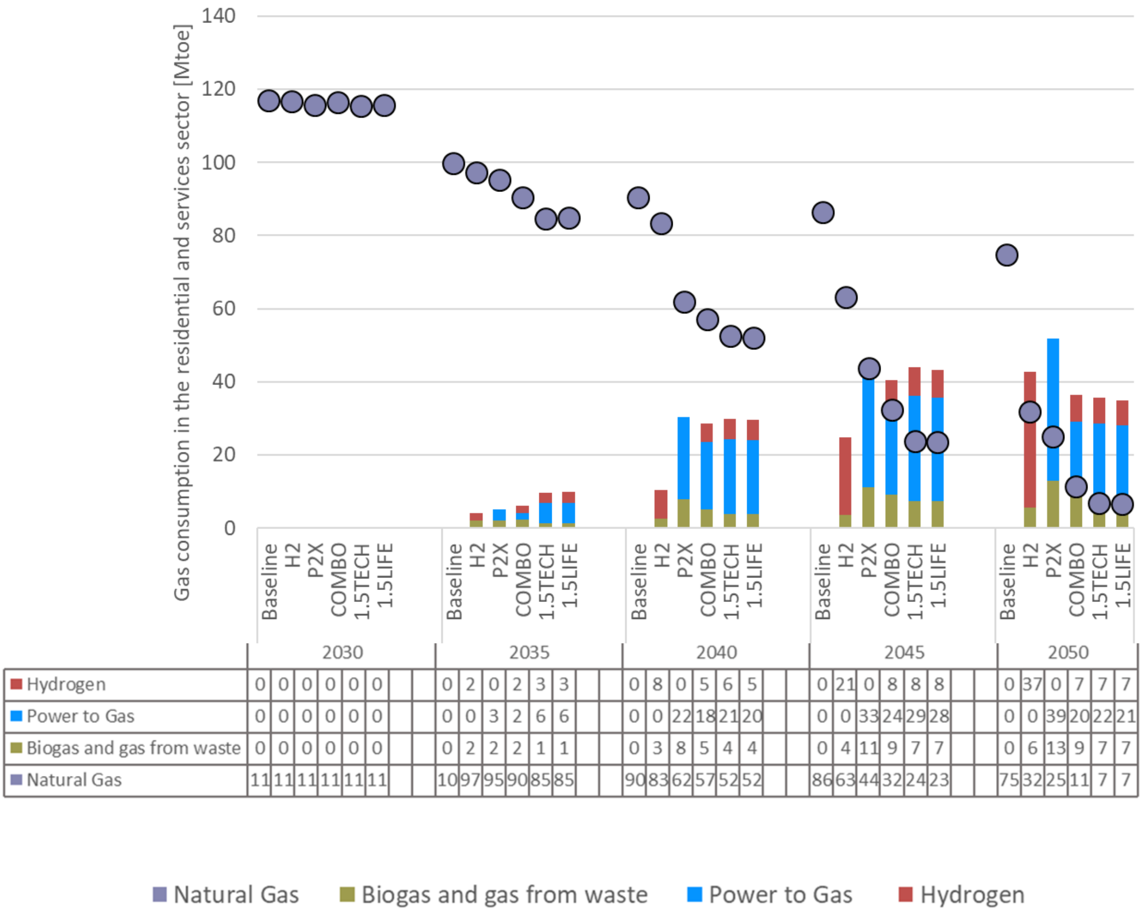


Figure 12 Natural gas consumption (fossil) in transport (source PRIMES)



2030	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	0	0	0	0	0
Power to Gas	0	0	0	0	0	0
Biogas and gas from waste	0	0	0	0	0	0
Natural Gas	11	11	11	11	11	11

2035	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	2	0	2	3	3
Power to Gas	0	0	3	2	6	6
Biogas and gas from waste	0	2	2	2	1	1
Natural Gas	10	97	95	90	85	85

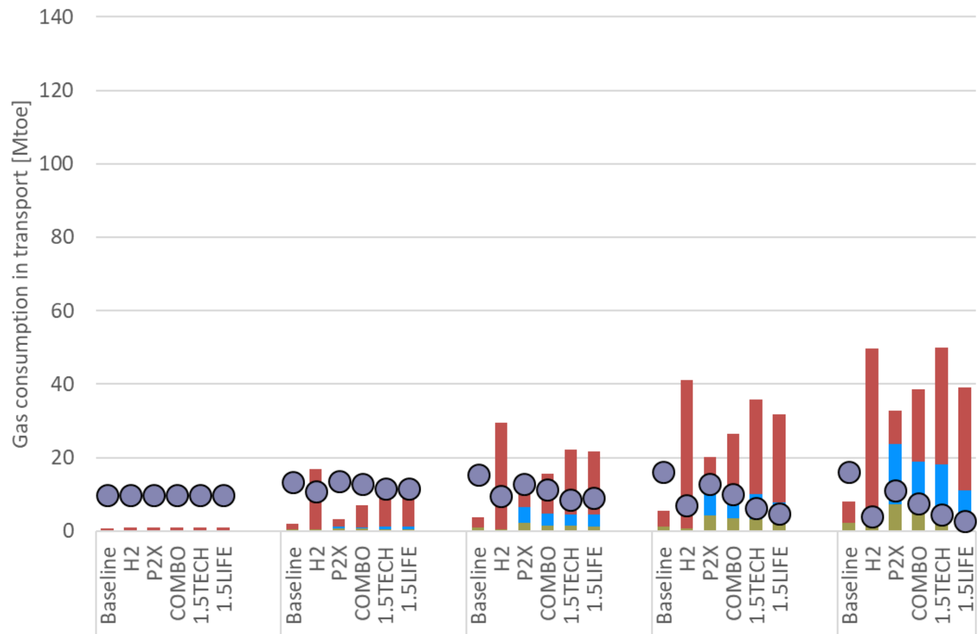
2040	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	8	0	5	6	5
Power to Gas	0	0	22	18	21	20
Biogas and gas from waste	0	3	8	5	4	4
Natural Gas	90	83	62	57	52	52

2045	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	21	0	8	8	8
Power to Gas	0	0	33	24	29	28
Biogas and gas from waste	0	4	11	9	7	7
Natural Gas	86	63	44	32	24	23

2050	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	37	0	7	7	7
Power to Gas	0	0	39	20	22	21
Biogas and gas from waste	0	6	13	9	7	7
Natural Gas	75	32	25	11	7	7

Figure 13 New-gas consumption in the residential and services sectors by type of gas. Consumption of conventional natural gas is also shown by scenario and projection year (source PRIMES)

Increased penetration of new gases in distribution networks may be also due to transport. Figure 12 shows that natural gas consumption (fossil) in transport increases by almost a factor of 3 in all scenarios in 2030 (in comparison to 2015 levels). In the decade 2035-2045, gas penetration in transport continues to increase in all scenarios that promote the use of hydrogen and Power to X technologies (P2X, Combo, Hydrogen), Figure 14.



2030	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	0	1	1	1	1	1
Power to Gas	0	0	0	0	0	0
Biogas and gas from waste	0	0	0	0	0	0
Natural Gas	10	10	10	10	10	10

2035	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	1	16	2	6	10	10
Power to Gas	0	0	0	0	1	1
Biogas and gas from waste	1	0	1	1	1	1
Natural Gas	13	11	14	13	12	12

2040	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	3	29	4	11	18	17
Power to Gas	0	0	4	3	3	3
Biogas and gas from waste	1	1	2	2	1	1
Natural Gas	15	10	13	11	9	9

2045	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	4	40	7	16	26	24
Power to Gas	0	0	9	7	7	5
Biogas and gas from waste	1	1	4	4	3	3
Natural Gas	16	7	13	10	6	5

2050	Baseline	H2	P2X	COMBO	1.5TECH	1.5LIFE
Hydrogen	6	48	9	20	32	28
Power to Gas	0	0	16	12	12	8
Biogas and gas from waste	2	2	7	7	6	4
Natural Gas	16	4	11	7	4	3

Figure 14 New-gas consumption in transport by type of gas. Consumption of conventional natural gas is also shown by scenario and projection year (source PRIMES)

Overall, gas consumption at distribution in 2050 decreases from 2030 levels by 22-34%. The respective decrease from 2015 levels of order of 40-50% depending on the scenario. Cumulative penetration of new gases at distribution level (residential, services, agriculture and transport) is less than 1% in 2030 (less than 1 Mtoe). In 2050, the ratio between new gases and conventional gas is from 1/3 (24% of total, 24Mtoe in the baseline scenario) to 1.28/1 (56% of all gas, 54 Mtoe in the 1.5TECH scenario), Figure 15.

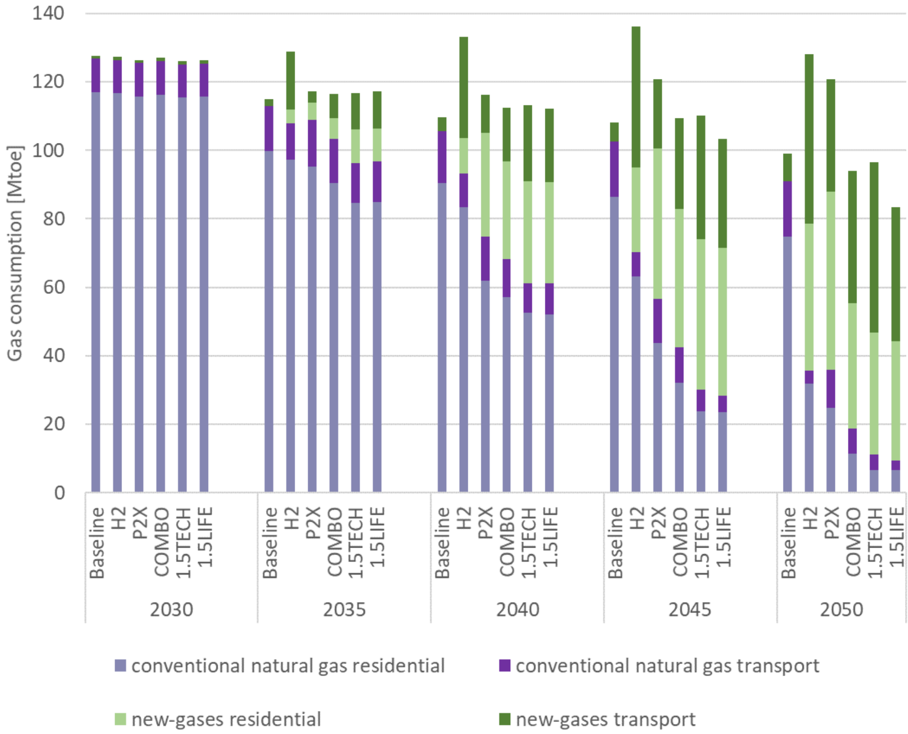


Figure 15 Total consumption of gas (fossil and new gas) at distribution level (source PRIMES)

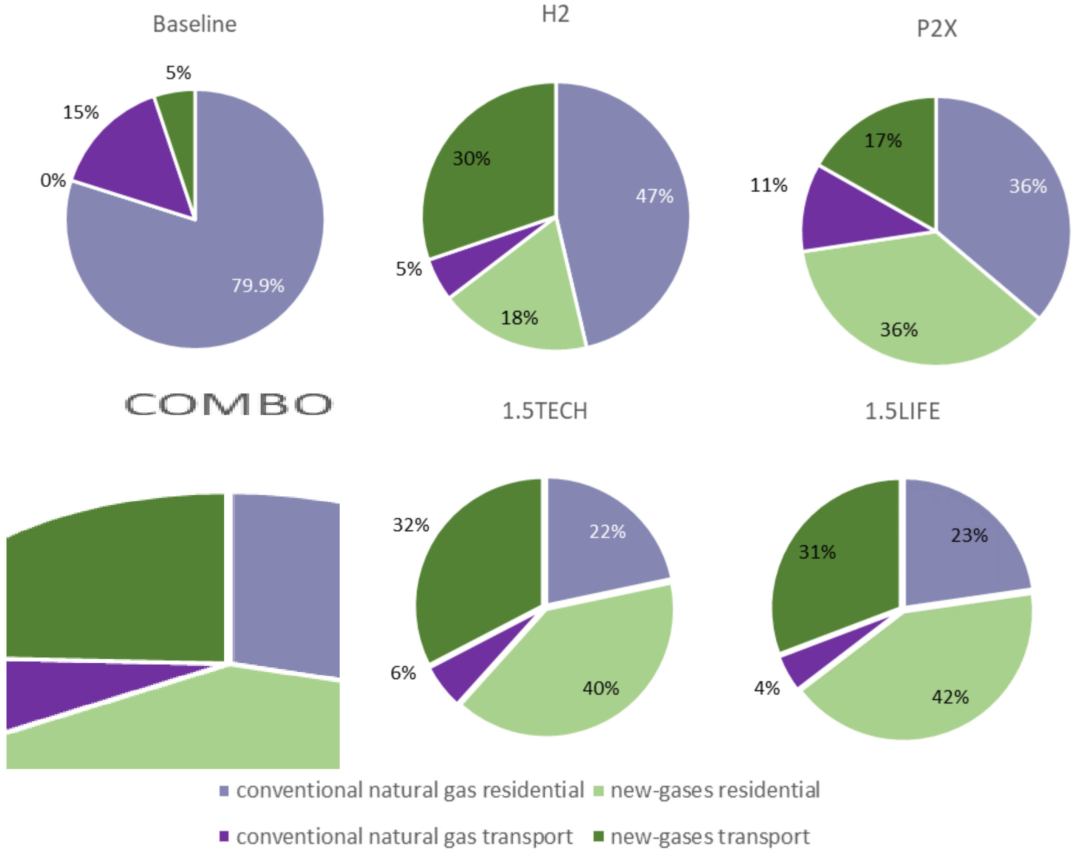


Figure 16 Share of conventional and new gas consumption at distribution level70 in 2050 (source: PRIMES)

DSO Role and Identified Barriers towards Energy Transition

The current role of the DSO in the gas system

According to Directive 2009/73/EC (Gas Directive), a DSO is a natural or legal person who carries out the function of distribution i.e. the transport of natural gas through local or regional pipeline networks with a view to its delivery to customers, but not including supply.

One of the fundamental objectives of the Gas Directive is to ensure non-discriminatory third-party access (TPA) to gas networks (distribution and transmission)[47]. The role of network operators is crucial in achieving this objective. Therefore, the specific tasks and obligations for distribution system operators that the Directive mandates link mainly to the establishment of an effective TPA system and secondly to ensuring that the system is operated by an entity that is capable to guarantee the sound technical and economic operation and development of the network.

In particular, Article 25 specifies the tasks of a DSO as:

- **Being responsible for ensuring the long-term ability of the system** to meet reasonable demands for the distribution of gas.
- **Being responsible for operating, maintaining and developing** under economic conditions a secure, reliable and efficient system, with due regard for the environment and energy efficiency.
- **Not discriminating between system users or classes of system users**, particularly in favour of its related undertakings.
- **Providing any other distribution, transmission, LNG, and/or storage system operator with sufficient information** to ensure that the transport and storage of natural gas takes place in a manner compatible with the secure and efficient operation of the interconnected system.
- **Providing system users with the information they need for efficient access to, including use of, the system**.

Where a distribution system operator is also responsible for balancing the distribution system, rules adopted for that purpose shall be objective, transparent and non-discriminatory, including rules for the charging of system users for energy imbalance. Terms and conditions, including rules and tariffs, for the provision of such services by distribution system operators shall be established approved by the NRAs and published.

Traditionally, distribution systems receive natural gas from the transmission system, of quality specified and monitored by the TSO and of pressure also regulated by the TSO. This gas is subsequently distributed to end-consumers who use gas appliances and machinery which complies with the specific gas norms of the network gas. New connections realised by the DSO typically concern connections to end-consumers i.e. to demand. However, as the gas system has reached high penetration levels in most of the Member States, new demand connections rate is relatively low. An analysis based on the National Reports submitted by NRAs to the European Commission and the CEER in the period 2008-2012 shows that a significant increase in the number of new household connections, of above 15% relative to 2008 levels is identified only in four MS: Bulgaria, Greece, Northern Ireland and Portugal. A moderate increase in the number of household

[47] See Article 32 of Directive 2009/73/EC.

connections, between 5% to 10% of 2008 levels is identified for Germany, Italy, Romania, Slovenia, Spain and the Netherlands. For the remaining Member States the number of connections remains relatively stable[48]. Thus, over the past years, in many cases, DSOs did not perform substantial network expansions or new connections but rather continued to ensure the stable operation of the existing system. There have been three main changes in distribution over the last decade mostly related to the implementation of the third energy package.

- The first change relates to the tasks and unbundling rules for the DSOs. Although the main requirement for legal unbundling for DSOs with more than 100,000 customers was foreseen since the 2nd Energy Package, the Gas Directive clarified that the DSO is the entity responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of gas and for operating, maintaining and developing under economic conditions the network (Article 25.1). The Directive also states that the DSO shall have at its disposal necessary resources including human, technical, financial and physical resources (Article 26.2(c)) so that its tasks are fulfilled. The Directive further calls for a compliance programme and a compliance officer to ensure that unbundling requirements are met (Article 26.2(d))
- The second change is related to the conclusion of market liberalisation which opened distribution networks to suppliers other than the incumbent and called for the establishment of network codes, tariff regulations and standardised contracts for network access. Rules for balancing were also developed.
- Finally, a limited digitalisation and limited penetration of gas smart meters is in a comparatively advanced stage of development in 4 Member States (France, Italy, the Netherlands and Luxemburg) and Great Britain. For the remaining Member States, cost benefit analysis yielded negative results[49].

When it comes to supply (injection) of natural gas directly into distribution network, this is typically the case where indigenous production of natural gas or other type of gases exist. During our research we were not able to identify a consolidated record of the production capacities of conventional gas and the distribution networks that host such plants, as this kind of information is not publicly available. Information regarding the injection of new gases is available up to a certain extent and this is reported in Section 0.

Figure 17 provides a visual on the tasks of the gas system operator under the 3rd Energy Package. Physical flows at distribution level stem from the city gates[50] to end consumption. The relationship between customers and the DSOs is relatively straightforward[51]: a new customer (typically demand) determines the size of the connection required, the network operator determines the cost of that connection, and the customer decides whether to proceed with the connection on that basis. General network reinforcement is based on a relatively predictable growth in demand. The DSO operates the network receiving gas of known quality from the TSO. Seasonality of demand is known and accommodated for in the planning and operation of the system. Market opening has

[48] K.Sardi, A. Mengelsons & N. Tourlis (2014), Recommendations based on the best practices of EU countries with respect to rules and procedures for connection as well as connection tariffs for the Electricity and Gas networks. Ad Hoc Expert Facility under the "INOGATE Technical Secretariat & Integrated Programme in support of the Baku Initiative and the Eastern Partnership energy objectives", http://www.inogate.org/documents/64_AM_ITS_version_E_to_F_Final_Report_270314.pdf, page 85

[49] https://www.vert.lt/SiteAssets/teises-aktai/EU28%20Smart%20Metering%20Benchmark%20Revised%20Final%20Report.pdf

[50] Connection points between transmission and distribution networks.

[51] Baringa, The future role of network operators: GB experience and its relevance to the pending European market redesign, https://www.baringa.com/getmedia/9174062a-ecc8-4032-9129-04b5573e44f8/The-future-role-of-network-operators-the-emerging-active-DSO-model/. The paper refers to electricity is also expandable to natural gas.

resulted in at least legal and functional unbundling of the DSOs[52] from supply and to the development of network codes and standardised contracts that DSOs sign with retail suppliers. Tariffs for network use are typically charged at exit points to end-consumers.

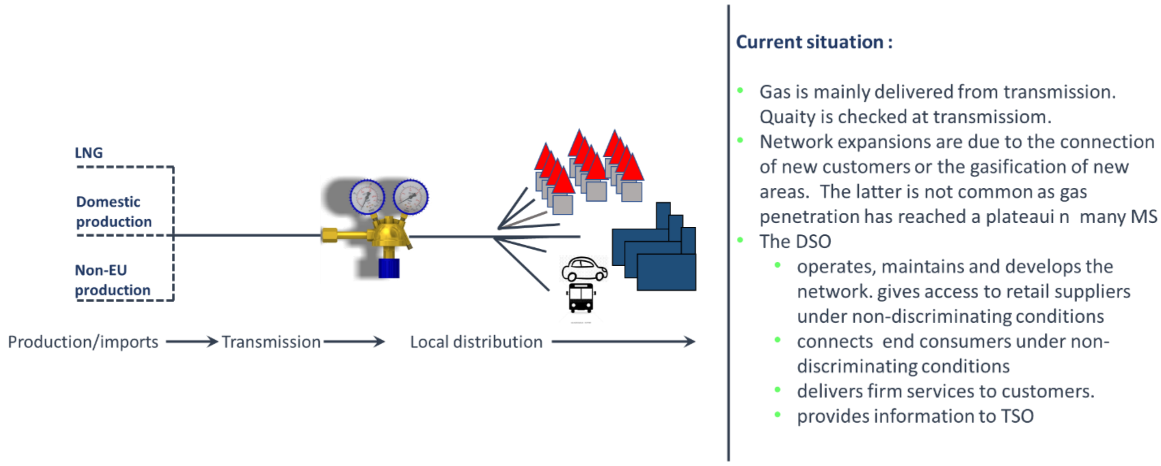


Figure 17 Business model and tasks of gas distribution system operator as envisaged by the 3rd Energy Package.

Distribution system operation and role of DSOs during energy transition

During energy transition, i.e. from early 2020s until 2040-2045, it is expected that conventional fossil natural gas introduced at transmission level shall remain the main source of gas. Small quantities of biomethane may also be injected at transmission level. New gas production facilities shall gradually also connect at distribution. Gas injection to distribution shall be mainly biomethane with smaller quantities of hydrogen (towards the end of the energy transition period). For new connections to be realised, DSOs shall need to develop a proper framework with standardised connection contracts for gas injection. Non-discriminatory access conditions shall also need to be specified for producers.

Network planning and network development shall gradually become an important part of the DSO tasks. Distribution system development plans shall need to consider the increased injection of new gases. The installation of compressors to inject new gas in transmission and odorant removal facilities may also be considered towards the end of the transition period. New rules for the allocation of costs between transmission and distribution regarding integrated network planning shall need to be developed. DSOs shall be also undertaking relevant studies to quantify the technical implications of accepting higher hydrogen blends in their networks.

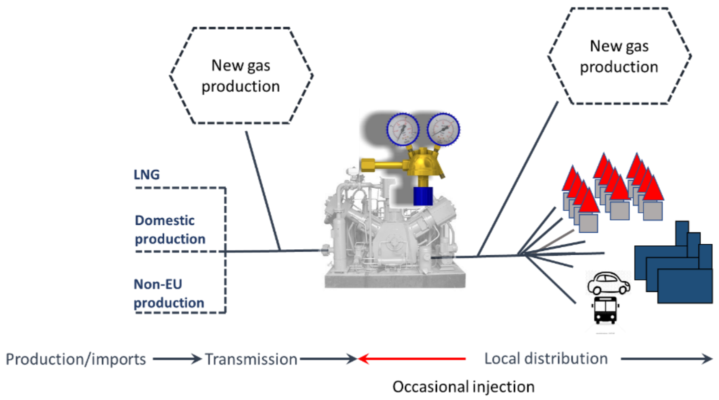
The role of the DSO in daily network operation shall be expanded to include obligations on gas quality metering and forecasts. Network pressure monitoring procedures and linepack operation shall become more diligent, and methodologies for the optimal use of linepack shall need to be developed. Tariff methodologies for the use of the distribution system shall be revised to take into account gas injection (including injection to transmission). TSOs and DSOs cooperation shall be expanded to address operational issues such as physical flows to transmission. Communication between DSOs, consumers and producers, including metering, shall be increasingly based on smart solutions.

[52] Smaller DSOs (below 100,000 customers) can be exempted from the legal and functional unbundling requirements and must comply only with accounting unbundling.

Installation of smart metering systems may become necessary to better manage storage constraints.

During energy transition, dedicated hydrogen networks continue to serve industrial customers. Need for regulation of such networks is not expected to rise but only at the latter stages of transition. New-gas producers shall be new entrants to both the wholesale and retail markets. It is expected that they will be concluding bilateral contracts with suppliers and end-consumers and/or become active participants at the local Virtual Trading Point (VTP). End-consumers shall develop a green orientation in their supply preferences. As new market players, new-gas producers may face additional entry barriers. End-consumer switching to green products may be limited due to lack of awareness and complexities and hidden costs during switching. Obligations for a certain percentage of new-gases to be included in the gas supplied and mix disclosure obligations may facilitate penetration.

As new-gases come with a variety of combustion properties and carbon content, a Guarantees of origin (GO) market focusing on new-gas GOs shall be gradually developed. Given experience with electricity, rules for GO market operation cross-border harmonisation shall be a process that can be concluded comparatively early in the transition period.



Energy Transition:

- Gas is delivered manily by transmission.
- Smaller quantities are injected also at distribution. Quantities increase in time
- Quality is checked at distribution level taking into account mixing effects between gas from transmission and new gas from local production and the location of end consumers.
- Most network expansions are due to the connection of new production and to address flexibility constraints.
- The installation of a compressor may be required in several networks towards the end of the transition period
- New gas production is mainly biomethane
- The DSO ccontinues to operate, maintain and develop the network.
- Non discriminating access conditions need to be specified also for producers. DSO's are technology neutral. Tariffs models may need to be revisited.
- Network planning needs to be done in collaboration with TSOs. Regular exchange of information with TSOs is essential
- Gas DSOs face many of the issues regarding digital transformation, data management and cyber security that are faced by electricity DSOs

Figure 18 Business model and tasks of gas distribution system operator in the energy transition (own analysis based on this study).

Distribution system operation and role of DSOs at steady state.

Around 2050 a 'steady state' is achieved where the injection of new gases including hydrogen maybe as high as over 70%, Figure 16 (scenarios 1.5TECH and 1.5LIFE) Technical barriers related to the acceptance of hydrogen injection will be resolved. Fossil gas injections at transmission level are significantly reduced. Dedicated hydrogen networks shall also serve a variety of end consumers and shall be subject to regulation as remaining gas networks.

Transmission and distribution shall be integrated with compressors installed and in operation pushing excess gas introduced at distribution levels to transmission. Smart meters with quality sensors shall be installed at all network branches. Non-discriminatory access conditions for producers to connect at distribution level shall be well established at all MS. A national entity integrating electricity and gas TSOs and connected DSOs shall be in place to facilitate coordination. Figure 19 provides a visual summary of the 'steady state'.

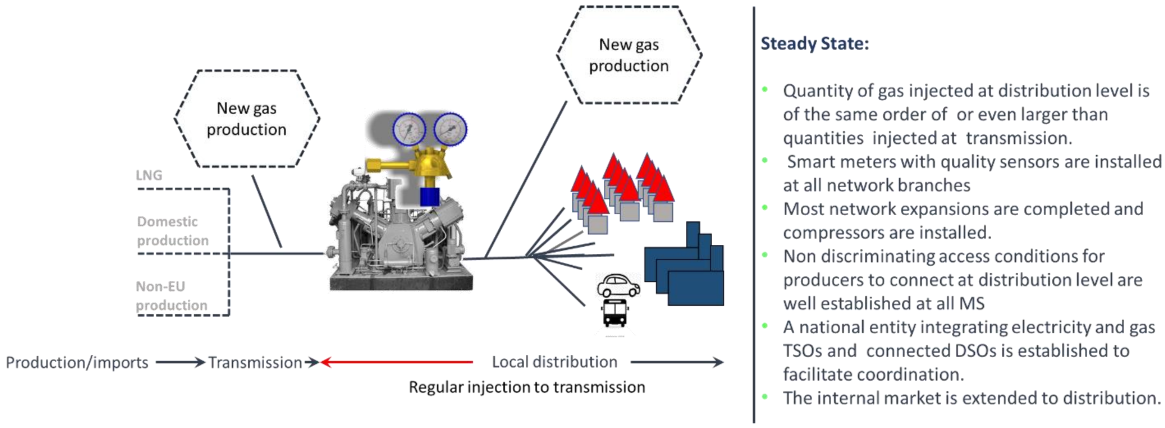


Figure 19 Business model and tasks of gas distribution system operator at steady state (own analysis based on this study).

Review of the proposals of ACER and CEER on the future role of DSOs

European regulators have identified a transitional role for both electricity and gas DSOs as early as in 2013-2014 and put forward four main principles[53]:

1. DSOs must run their business in a way that reflects the reasonable expectations of network users and other stakeholders including new entrants and new business models, now and in the future.
2. DSOs must act as neutral market facilitators in undertaking their core functions
3. DSOs must act in the public interest taking account of the costs and benefits of different activities.
4. The consumer owns his/her data and DSOs must safeguard that data when handling it.

The four points as outlined above are taken into account in the "Energy Regulation: A Bridge to 2025 Conclusions Paper"[54] of ACER published in 2014 (hereinafter ACER 2025 Bridge Paper). The paper provides the Agency's regulatory response to future challenges emerging from developments in the internal energy market. Amongst other topics, the paper looks into the expected role of distribution system operators in the internal energy market of 2025. Although the paper acknowledges that the most significant changes will be affecting electricity DSOs, a series of proposals also target gas

[53] Lord Mogg, former Chairman of the Board of Regulators ACER and CEER President, keynote speech on the 2015 High Level Conference on Energy Market Design.
[54] https://www.acer.europa.eu/official_documents/acts_of_the_agency/sd052005/supporting%20document%20to-%20acer%20recommendation%2005-2014%20-%20%20energy%20regulation%20a%20bridge%20to%202025%-20conclusions%20paper.pdf

DSOs. We have identified such specific topics and summarise them, together with our comments in Table 1 and Table 2 below.

Table 1 Summary of the recommendations on the role of the DSOs as included in the ACER Bridge to 2025 Paper and high-level assessment by the consultant in relation to new gases

Recommendations in the ACER Bridge to 2025 Paper	Comments of the Consultant in relation to new gases
DSOs must be neutral market facilitators in undertaking their core functions to enable the development of new market-based services to consumers by third parties. DSOs' role as market facilitators must be consistent with their responsibility to ensure secure system operation. At the same time DSOs may also need to adapt their networks to meet new demands	The Gas Directive already provides for the neutrality of the DSOs and their role as neutral market facilitators. On the other hand, DSOs should be able to enshrine innovation and adapt their networks and functions for accommodating the energy transition. There may be a scope for the development of national roadmaps of actions targeting specifically DSOs. These roadmaps may stem from the National Energy and Climate plans of Regulation (EU) 2018/1999 with specific actions for gas DSOs. Gas DSOs and NRAs should consult on the roadmaps. Incentive based regulation will have a role to play as a well-balanced means towards promoting innovations. Energy transition has a cost and actions need to be carefully designed. NRAs should develop a methodology for the evaluation of cost versus benefits of DSOs proposals and evaluate the impact of innovative actions on network tariffs.
DSOs may use smart grid solutions to manage efficiently the much greater penetrations of generation (particularly low-carbon technologies, including renewable-based generation) connected to distribution networks at least cost. DSOs will need to manage their networks actively. As a result, there will also need to be greater co-ordination between DSOs and TSOs on network operational matters. Cooperation between the DSOs and the TSO must be effective as the requirement for active network management by DSOs increases as a result of greater distributed generation	Smart technologies for gas networks also include quality sensors and calculation methods to determine local quality of gas within a network receiving gases from multiple sources and of various combustion characteristics (e.g. new gases and conventional natural gas). A structured cooperation is necessary for the better coordination and network planning. We will be discussing further on the issue of cooperation in the next Section.

Recommendations in the ACER Bridge to 2025 Paper	Comments of the Consultant in relation to new gases
DSOs should increase resilience to existing and new threats to security of supply, including cyber-security threats. In parallel with this, DSOs should ensure that consumer's data privacy is maintained.	There may be a scope to include additional provisions in the gas legal framework in analogy to the ones included in the new electricity Directive in relation to data management. This topic is addressed in the next Section.
Non-discriminatory access to the distribution network is essential for downstream access to customers at retail level. Moreover, legal and functional unbundling of DSOs was required, in Directive 2003/54/EC, only from 1 July 2007 and its effects on the internal market in electricity are still to be fully evaluated. The rules on legal and functional unbundling currently in place can lead to effective unbundling provided they properly implemented and closely monitored.	The CEER status review published in June 2019 acknowledges that unbundling of gas DSOs has been finalised according to the provisions of the Directive on the majority of the DSOs in Europe. Participating NRAs have all considered that DSOs have sufficient financial resources under their immediate control to ensure decision-making power and independence in their work. Almost all the participating NRAs confirmed that compliance officers have enough information and resources to fulfil their tasks independently. Their reports are used by NRAs to further monitor implementation of the compliance programme. However, DSOs currently participate in consortia involved on R&D projects related to new gases. On the one-hand these actions of the DSOs should not be inhibited. On the other hand, a careful balance needs to be preserved between the role of the DSO as the operator of a regulated activity and its involvement in a market-based activity such as the production of new gases. This topic is further addressed in the next Section.
The activities of vertically-integrated DSOs, as regards their influence on the development of competition, in in relation to household and small commercial customers, in order to facilitate a level-playing field at retail level should be monitored. The adequacy of the current rules on business separation will be assessed against the evolving role of DSOs.	Monitoring by NRAs of all DSO activities in relation to new gases is necessary. Currently activities are confined into a small scale. A timeline may need to be introduced in the legal framework stating that depending on progress rules and conditions will need to be revaluated. The option of a dynamic regulation was also brought up by ACER in a recent decision

Recommendations in the ACER Bridge to 2025 Paper	Comments of the Consultant in relation to new gases
New services to consumers will emerge in the space currently occupied by DSOs. These services may relate to demand-side energy management or to other energy services and may be coupled with non-energy services. These new markets should not be foreclosed by existing energy players, and by the activities undertaken by incumbent monopoly DSOs. In this regard, unbundling rules must be respected. DSOs may use smart grid solutions, including flexibility services, to optimise the efficient operation of the network ultimately to the benefit of consumers. The regulatory framework should enable the introduction of new services and efficient cooperation among market players including DSOs and should facilitate the development of efficient network solutions, including smart grids.	A potential emerging service is that of flexibility and use of linepack at distribution level.
Regulatory incentives and other regulatory mechanisms may be considered, as appropriate, to encourage DSOs to respond to new challenges and opportunities and to facilitate innovation and research and development. Distribution tariff structures will be reviewed to ensure the efficient use of distribution networks, including through an assessment of whether the costs imposed on networks by their usage at peak times should be reflected in tariffs.	This recommendation is also well fit for the introduction of new gases.

Table 2 Summary of the recommendations on retail markets included in the ACER Bridge to 2025 Paper and high-level assessment by the consultant in relation to new gases

Recommendations in the ACER Bridge to 2025 Paper	Comments by the Consultant in relation to new gases
Retail markets for gas and electricity should be competitive to ensure that consumers receive the full benefits of the IEM.	▪ New gases should not create barriers to internal market functioning (including the trade of appliances in the internal market) and should not distort competition (for example through unclear or inconsistent quality standards). ▪ On the other hand, as new gases constitute an element of the European Long-Term Strategic Vision, their penetration should be facilitated. ▪ Experience from the various schemes promoting RES and employed over the last two decades should be used. ▪ Although the supporting scheme per se is more a national matter, major EU framework such as the state aid guidelines remain applicable and should be considered. Lessons learned from the promotion of RES electricity should be taken into account by NRAs

Recommendations in the ACER Bridge to 2025 Paper	Comments by the Consultant in relation to new gases
Consumers should have a real choice of a wide range of service offers. Consumers are likely, in many markets, to be charged on the basis of dynamic pricing for their consumption which will enable them to manage that consumption in ways which reduce their overall bill so that consumers can continue to receive reliable and affordable energy supplies when they require them	Consumers should have a choice of service offers. Development of consumer awareness regarding new-gases and their benefits (reduced carbon footprint, RES source, reduction of import dependency if produced within the EU) is needed, particularly for households. Dynamic pricing may not be directly applicable to gas (including new gas) as time-scales in the transportation of gas are substantially larger in comparison to electricity. The EU gas market has been developed according to the EU gas target model comprising interconnected entry-exit zones with virtual trading points (VTPs). The emergence of new-gas producers connected at distribution may imply a gradual integration of distribution and transmission. In all cases, national market models should not create barriers for producers, or suppliers of new gases to access and freely trade at VTPs. The role of the new producers in the retail and the wholesale market may need to be further clarified.
Consumers will increasingly also be electricity producers. Consumers will be able to use new smart technologies to manage their energy consumption and production, or may choose to engage service providers to manage their interface with the energy market which will simplify the process of consumer engagement and choice	*Not applicable to natural gas*. As new gas technology is still on a rather experimental level and capital intensive it is unlikely for natural gas consumers to transform into prosumers. On the other hand, electricity producers using biogas are already deciding on whether to transform their produced gas directly into electricity on spot or to feed in gas. In that sense they are already sector-coupling prosumers – a more advanced stage than the one classically encompassed by the term.

Recommendations in the ACER Bridge to 2025 Paper	Comments by the Consultant in relation to new gases
Consumers will need to be properly informed, as well as protected and empowered, if they are to make informed choices.	Information on new gases, on their sources and life-cycle emissions is an important element of the overall process towards decarbonisation. Guarantees of origin have an important role to play here together with resource disclosure obligations. The electricity legal framework (e.g. Directive (EU) 2019/944 and its previous editions) called for disclosure of energy sources. Electricity suppliers have been obliged to specify in their bills the contribution of each energy source to the electricity purchased by the final customer in accordance with the electricity supply contract (product level disclosure). A similar disclosure mechanism should be considered to be introduced in the case of natural gas. The primary nature of a GO is to provide proof to final customers that a given share or quantity of energy was used was produced from renewable sources (or a gas of reduced carbon footprint). GOs should be related to a mixture disclosure obligation upon the suppliers. Such a disclosure obligation would need to be introduced into the legal framework. If GOs are on a voluntary level, a residual mix methodology as this existing in electricity will also need to be developed for gas.
Retail markets should be fully open to new market entrants from other Member States and, as far as possible, integrated across national borders.	Clear rules on the connection of new production facilities need to be established. The legal framework should facilitate the trade of new gas at virtual trading points A standardised GO system can allow for cross border trade of guarantees and thus allow retail producers to benefit from new gases produced anywhere in Europe.
The benefits of the IEM will be delivered to consumers through the establishment of competitive national retail markets. The CEER issued in 2017 a roadmap to 2025 Well-Functioning Retail Energy Markets.	The roadmap calls for the NRAs to collect data on specific metrics to assess retail market functioning. Monitoring should be gradually expanded to include new-gas production[55].

[55] Roadmap to 2025 Well-Functioning Retail Energy Markets (Ref: C17-SC-59-04-02) https://www.ceer.eu/documents/104400/-/-/7b0fa15a-c2e2-c950-0350-060263896e36

Recommendations in the ACER Bridge to 2025 Paper	Comments by the Consultant in relation to new gases
Encourage new entry by energy suppliers, including from other Member States **through identification of a** minimum standards (e.g. for supply licences, for DSO/supplier contracts and for the exchange of customer data) in order to remove market barriers and facilitate the entry of new suppliers, including those from other Member States, into national retail markets.	
Regulated end-user prices are not compatible with the objective of establishing liberal competitive retail markets	Regulated end user prices can be a barrier to the introduction of new gases. This topic should be further investigated in the markets where end-user price regulation remains and the effects on the penetration of new gases should be evaluated. There may be a scope to include a relevant provision with a timeline in the legal framework.
European energy regulators will continue to undertake effective market monitoring (including in respect of the relationship between wholesale and retail prices) to identify market distortions which are inhibiting the development of competition	Provisions for monitoring competition also in relation to new gases would need to be introduced. There may be a scope for ACER to include in the Market Monitoring Report a new Section reporting on the penetration of new gases.

Following the ACER Bridge paper, the 2015 CEER paper on the role of the DSOs[56] concluded that:

- DSOs may be allowed to perform activities even if there is a potential for competition under certain conditions or regulatory controls, if there is a clear, specific justification, possibly based on a cost/benefit analysis. Examples of these conditions include limiting the level of engagement by the DSO, limiting the period of involvement in the new activity and introducing transparency requirements. This recommendation set a base for the provisions in the new electricity Directive (EU) 2019/944 regarding the ownership of storage facilities. Note that in 2019, CEER consulted further on this topic, specifically for natural gas[57]. In the evaluation of responses document, one group of respondents, mainly commercial market actors, were of the view that TSOs/DSOs should not be active in activities open to competition, another group, mainly network operators, were of the view that TSOs/DSOs should be allowed to invest in power-to-gas and biomethane plants to support scaling up of the market. CEER summarising

[56] Ref: C15-DSO-16-03, The Future Role of DSOs A CEER Conclusions Paper, https://www.ceer.eu/documents/104400/-/-/60e13689-9416-047e-873a-2644a74c9640

[57] CEER, Ref C18-RGS-03-03, Stakeholder Comments on CEER's Public Consultation on Regulatory Challenges for a Sustainable Gas Sector, Evaluation of Responses, https://www.ceer.eu/documents/104400/-/-/031e2bd0-7801-ff04-bc7c-c20135fffc5e

the contributions noted a need for clarifying the legal framework regarding the conditions under which an involvement of TSOs/DSOs in new activities may be allowed along the lines of the electricity directive.

- There is a need for better planning and coordination between DSOs and between DSOs and TSOs, but also between electricity and gas system operators. There should be a general principle of subsidiarity, with decisions taken at the right time by the most appropriate entity. Changes could be made now to ensure adequate communication and information exchange between TSOs and DSOs, real time exchange of data, more coordinated planning and decision making, and greater transparency and communication with stakeholders.

In the paper, CEER draws conclusions also on a number of additional topics - the incentives on DSOs to foster innovation, the form of regulation, the treatment of expenditure on flexible and smart solutions, the extent to which network tariffs may need to change to reflect demand side response at retail level, and contractual arrangements involving DSOs. Some of these topics are further addressed in additional notes[58], guidelines and white papers.

Note that the ACER 2025 Bridge Paper and the CEER paper reviewed above do not fully incorporate the EU vision and commitment towards combating climate change, as some of the policy developments came after their publication. Nevertheless, they provide an excellent snapshot of how the market is expected to have evolved following the implementation of the gas target model as realised by Directive 2009/73/EC, Regulation (EU) 715/2009 and the European Network codes.

In its March 2019 consultation document[59], the CEER requested input on the following regulatory challenges in relation to new gases. Challenges identified by stakeholders and CEER are summarised in Table 3. A further consultation was also carried out by ACER in June 2019[60].

[58] CEER, Guidelines of Good Practice for Flexibility Use at Distribution Level Consultation Paper Ref: C16-DS-29-03, https://www.ceer.eu/documents/104400/-/-/db9b497c-9d0f-5a38-2320-304472f122ec, Distribution Systems Working Group Flexibility Use at Distribution Level A CEER Conclusions Paper, https://www.ceer.eu/documents/104400/-/-/e5186abe-67eb-4bb5-1eb2-2237e1997bbc , Incentives Schemes for Regulating Distribution System Operators, including for innovation A CEER Conclusions Paper, Ref: C17-DS-37-05, https://www.ceer.eu/documents/104400/-/-/1128ea3e-cadc-ed43-dcf7-6dd40f9e446b
[59] see footnote 57
[60] https://www.acer.europa.eu/Official_documents/Public_consultations/PC_2019_G_06/The%20Bridge%20beyond%202025%20-%20PC_2019_G_06.pdf

Table 3 Summary of the regulatory challenges identified in the 2019 CEER Consultation and recommendations proposed

Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
1. Ownership of new gas production by DSOs	▪ Lack of a clear legal framework for such activities of gas.	▪ Care would need to be taken not to allow TSO/DSO-operated assets to foreclose the market for the services these assets provide or use inside information. ▪ Support for investment in technologies that are not yet commercially viable may be justified to promote learning, but this is largely a matter for governments rather than regulators. ▪ Sandboxes could allow pilot projects for a limited time and scope as exemptions to the general rules. The EU legal framework could enable this across all Member States. ▪ Regulation (EU) 347/2013 could be amended to include these investments in the TYNDP and possibly as PCIs.
2. A mandatory common European threshold for the blending of hydrogen in gas networks with a deadline for implementation	▪ Lack of a mandatory target may inhibit cross border trade. ▪ Adoption of a mandatory level may lead to unnecessary refurbishments	▪ It is too early for the introduction of a European threshold for hydrogen blending. ▪ Situation differs for existing (industrial) networks and for (new or converted gas) hydrogen networks (connecting diverse supply and demand). It is important that this should be taken into account when deciding on if and how hydrogen networks should be regulated.

Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
3. The circumstances or conditions under which hydrogen networks should be regulated.	▪ Hydrogen business particularities (hydrogen networks exist for specific purposes servicing exclusively industry. ▪ Overregulation or too early regulation mimicking the regulation of may hamper market development	▪ Uncertainty over future regulation could hamper (and delay) investments in decarbonised gases. ▪ At the same time, it will be important to avoid unnecessary regulation of competitive activities. ▪ Existence of market failures like externalities and a risk for market dominance could be reasons for government intervention. Such intervention should be based on a thorough market analysis ▪ The scope of Directive 2009/73/EC could be extended to hydrogen.
4. Cost efficiency as a reason for proactive market intervention and whether such actions may be considered as contrary to a technology neutral approach	▪ Achievement of a technology neutral approach based on market mechanisms. ▪ Other criteria like SoS, diversification of resources, peak demand and societal and environmental impacts should be considered.	▪ Regulation should be neutral. ▪ Regulatory conditions should allow the most cost-effective technology to be developed. ▪ Support for investment should be of limited time and non-discriminatory. Support is largely a matter of governments rather than regulators. ▪ Clear policy goals and targets are needed. These can provide the trigger to invest in these new technologies.
5. The role of power to gas infrastructures	▪ Power to gas technology are not yet technologically viable.	▪ Subsidising specific technologies is not under the remit of the regulators: it is a political choice that should be left to policymakers.

Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
6. Distortions to the deployment of power to gas technologies due to electricity and gas tariff systems.	▪ Double charging in particular regarding taxes and levies. ▪ Power-to-gas should be classified as conversion service, as they transform one energy carrier to another. ▪ P2gas benefits (SoS, balancing, supporting renewable and decarbonisation, avoiding grid extension, etc) are not reflected.	▪ it is important to distinguish between use-of network tariffs (UoNT) and other charges or taxes. ▪ Network charges should be related to network costs in order to avoid distortive effects. Other benefits should be rewarded with appropriate instruments. ▪ The "regulatory status" of power-to-gas that can be vastly different from country to country. If power-to-gas were to be an element of the networks (i.e. an interface between gas and electricity networks), they may be regulated however, as it may interfere with competitive activities, this approach remains highly questionable. Instead, if power-to-gas installations are considered simply as network users, they have to be charged regular access charges.

Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
7. Other issues in relation to power to gas.	▪ Lack of a taxonomy of "green gas" ▪ Lack of a regulation assuring or, at least, encouraging power-to-gas plants to use "clean/green" electricity; ▪ Barriers for cross-border trade of renewable and low carbon gasses; ▪ Complex and non-unified procedures for power-to-gas permitting, connecting to the gas grid and market integration ▪ Connection tariff ▪ Lack of a communication protocol among TSO/DSO/Gas Network Operator/H2 producer for an efficient use of those technologies; ▪ Lack of a definition of power-to-gas in the legal framework legislation and those of the facility operator and user. ▪ Lack of a defined as demand-side response facilities. ▪ Lack of a framework exempting pilot projects from administrative burdens such as levies and charges; incentivising R&D and cross border cooperation; ▪ Lack of market design for P2hydrogen. ▪ Lack of support schemes	▪ Regarding definitions, the recommendation favours adopting consistent principles at European level and a dynamic regulatory approach. ▪ Technical and gas quality standards should be defined. ▪ The permitting system should be simplified and P2Gas facilities remunerated for services offered.

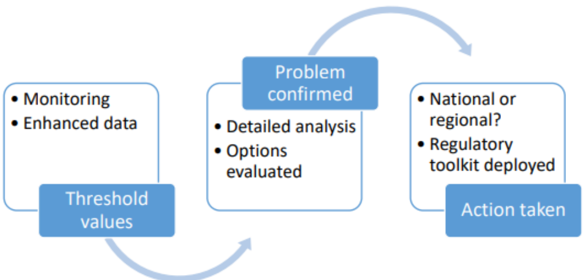
Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
8. Efficient cross border trading of gas GOs 9. Lessons learned from electricity GOs applicable to gas.	▪ Divergent opinions expressed regarding keeping the link between the GO and the molecule for more transparency towards the customer and trading the certificate independently from the commodity gas (book&claim). ▪ As gas is storable expiration of GOs as provided for electricity may need to be reconsidered. ▪ Lack of harmonisation on GO characteristics will hamper cross-border trading. ▪ The types of gases represented by a GO and whether full disclosure is necessary.	▪ Broad disclosure of the various origins of gas including low carbon and decarbonised gases. ▪ Definitions and criteria should unambiguously determine the different types of decarbonised gas and the extent to which each can be regarded as "green" or "low carbon". ▪ Renewable energy GOs should be disclosed towards customers within a reasonable period being issued.
10. ACERs and NRAs' responsibility in the development and approval of the TYNDP	*Not directly applicable to the scope of the present study*	▪ TYNDPs would merit further assessment by ACER and NRAs.
11. Decision making regarding new infrastructure	▪ Extension of EU NC CAM and Regulation (EU) 347/2013 may not be applicable as the former is completely market driven and the latter is market driven taking also into account externalities such as security or diversification of supply.	▪ Cross-references between EU NC CAM and the PCI regulation would help clarify the respective roles of different procedures and, especially, how to design and what to expect from market tests in the PCI procedures.
12. Risk of stranded assets 13. Assessment of decommissioning decisions.	▪ Reduction in gas demand may lead to early decommissioning of non-depreciated infrastructure	▪ Risks of stranded assets should be identified through the TYNDP. ▪ Responsibility of efficiency should be kept upon operators. Accelerated depreciation, which would result in increasing tariffs in the short-term should be avoided.

Consultation topic	Regulatory challenge identified by stakeholders and CEER	Summary of Recommendations provided by stakeholders and the CEER
14. Critical points to a gas market design 15. Need to update current market design	▪ Although significant progress has been made, there are still illiquid markets in the EU. ▪ Lack of standard conditions for grid access for power-to-gas national technical rules and standards regarding maximum hydrogen concentration. ▪ Current framework does not recognize/reward the full value of underground gas storages. ▪ Lack of guidance for market mergers especially regarding principles of ITC mechanisms is a critical point.	▪ The basic preconditions for that development should be put in place as soon as possible in order to allow for a gradual scaling-up of renewable or decarbonised gases in the period beyond 2025.
Questions 16 and 17 relate to gas transmission tariffs and the expiration of long-term contracts at transmission level and are thus not applicable to the scope of this study.		
18. Other topics to be considered	▪ Absence of a comparable CO2 cost of between EU and extra-EU competitors will promote a significant disadvantage. ▪ Possible contradictory national regulation ▪ Storage challenges ▪ 5-Year revision of the negative technical and economic study regarding the roll out of smart gas meters. ▪ Barriers to cross border trade	▪ Promote regulatory sandboxes and pilot-projects in order to incentivise R&D in this field. ▪ Create an EU gas DSO entity which should be different from the EU electricity DSO entity. ▪ Create visibility and transparency of imported hydrogen products to distinguish that produced from RES and that from fossil-fuels. ▪ Carbon capture and Storage (CCS) and Carbon capture and utilization (CCU)TSOs should be allowed. ▪ Review the current regulatory tariff design. ▪ Incentives to develop/deliver carbon-free (or low-carbon) products of (traditional) gas producers.

Finally, on November 2019, CEER and ACER published jointly an update to ACER Bridge to 2025 Paper. The new document entitled "The Bridge Beyond 2025 Conclusions Paper[61]" builds a vision of the energy market post the Clean Energy Package (CEP) and makes direct reference to new-gases by acknowledging that "*Decarbonised gases should be able to be integrated into existing gas markets, with full valuation of their environmental benefits, and captured in market monitoring through sustainability indicators published alongside GTM metrics. Clear definitions and categorisation of decarbonised gases, including carbon capture and use or storage, should be established in European legislation, and consistent principles should be applied across the EU to facilitate the blending of decarbonised gases. Legislation should be sufficiently flexible to allow the emergence of new gases/technologies."*

The publication builds across four thematic areas. The recommendations of ACER with relevance to the new-gas market are summarised in Table 4. The purpose of the summary is to provide a background for the assessment to follow in the next Sections. Readers should consult the original paper for further information.

Table 4 Summary of the ACER Bridge Beyond 2025 Paper

Thematic Areas	ACER Recommendations
THEME A Access and market monitoring	▪ Alongside the GTM metrics, sustainability metrics are needed to give a fuller picture of the extent to which the sector is operating successfully. ▪ A structured procedure based on the definition of threshold values and a more detailed analysis by the NRAs is proposed. ACER's recommendations on this Theme are discussed further in Section 0  ▪ Development of a system of mutual recognition for wholesale market authorisations/licences across the EU based on well-defined standardised minimum requirements, including in relation to the reliability and financial solvency of the entity.
THEME B Governance of infrastructure and oversight of existing and new entities	▪ The governance arrangements in gas should be brought into line with those recently updated for electricity in the CEP (especially in a context of sector coupling and a holistic system view in the future). This alignment will involve changes to the gas legislation in relation to the TYNDP, Network Codes, the Agency's powers, enforcement of the compliance of ENTSOG with its obligations, exemptions and planning obligations for distribution systems.

[61] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/SD_The%20Bridge%20beyond%202025/-The%20Bridge%20Beyond%202025_Conclusion%20Paper.pdf

	Regulators consider that the revised governance for the relationship between the Agency and ENTSO-E set out in the CEP is equally relevant in respect of ENTSOG. Further, in terms of overall energy governance, the ENTSOs should be obliged to submit their annual work programme and their sufficiently detailed budget for approval to the Agency. The Agency should have the ability to request an amendment, if it deems the work programme and/or the budget to be insufficient to cover the ENTSO's legal obligations, as well as if it considers the budget to be too generous. Such oversight of the Agency needs to be coordinated with the NRAs overseeing their TSOs' contributions to the respective ENTSO's budget. ▪ The CBA methodology needs to be adapted to ensure that sustainability (including climate) effects of new investments are properly considered. The CBA methodology should include a full assessment of the decarbonisation effects and their monetisation. It should also be applicable for cases of decommissioning of assets, as well as of re-purposing of natural gas assets for use in a decarbonised future (which could include transportation of hydrogen or of carbon dioxide for use or long-term storage). ▪ DSOs above a size threshold, should be obliged to measure and report their methane emissions according to a standard methodology, with sufficient granularity to allow the identification of the highest emitters. The measurements should be followed by an action plan at system operator level to address emissions. NRAs should recognise efficiently incurred costs for regulated entities.
THEME C Dynamic regulation for new activities and technologies	▪ As technologies are still developing and the future mix is rather uncertain, we favour adopting consistent principles at European level and a dynamic regulatory approach, rather than including detailed rules in legislation at this stage ▪ New "green gas" production assets should be developed in a competitive market, supported in the early stages for technology development reasons, if government policy so decides. ▪ For the proper regulatory assessment of the impact of decarbonised gas production on the sector, including transmission system development patterns and trading, reliable fundamental data on gas production assets in place and planned should be systematically collected from TSOs, DSOs and GO issuing bodies, and should be available at European level. ▪ Provide for an "EU umbrella" for the sandbox approach, allowing time-limited derogations with the view to generate information that is useful in the public interest and there is no significant risk of a material impact on the wider market. The resulting lessons should be shared between NRAs to avoid the need to replicate the pilots in each Member State and to accelerate decisions on whether regulation or legislation needs to be adapted. ▪ Unbundling of regulated and non-regulated activities must be ensured in case that TSOs or DSOs become involved in new gas facilities. Care would need to be taken not to allow TSO/DSO-operated assets to foreclose the market for services these assets provide, to use their inside information to secure the best sites or

	to cross-subsidise the new projects putting the TSO/DSO in an unduly favourable position. This would likely include requirements for regulated third party access for all assets developed by TSOs or DSOs ▪ Where new infrastructure such as power-to-gas or biogas plants are developed by the market, there is a need to coordinate with network availability and development. This starts with the TSOs (and DSOs, where relevant) being required to publish information on relative ease of accommodation of new assets. Economic efficiency is likely to be best served if this is backed up through a price signal, such as connection charges, but in any event appropriate processes will need to be put in place to ensure that there is a level playing field. ▪ Consideration should be given to a regulatory framework for a pure hydrogen network. This might appear premature, as initial investments are being made in a competitive market (e.g. for use of hydrogen in industry) rather than as a network asset. The prospect of a widespread hydrogen network still seems some years away and is likely to be localised at first. However, uncertainty over future regulation could hamper (and delay) investments in decarbonised gases.
THEME D Transmission tariffs and cross-border capacity allocation	▪ On tariffs, regulators agree with the views of many stakeholders that the implementation of the Tariffs Network Code shall remain a priority. As noted above, at present tariff design does not appear to be causing major issues on a pan-EU basis. However, some stakeholders have highlighted that concerns about gas tariffs are already present in some regions and are expected to grow.

Barriers identified in the EC study on sector coupling

Consultants were appointed by the European Commission in 2018 to carry out a study on the integration of the EU gas and electricity sectors[62] (Sector Coupling Study). The study, published December 2019, presents results of the consortium's assessment on regulatory barriers and gaps preventing closer linking of the EU gas and electricity sectors (both in terms of their markets and infrastructure) and hindering the deployment of renewable and low-carbon gases.

To identify possible barriers and gaps, consultants drew on a range of sources, including country-based research into regulatory framework in a sample of Member States and input from stakeholders. Starting with any initially long list of barriers (many also applicable in the post transition period when a steady state has been reached), a shorter list of potential barriers was prepared. This list is summarised in Table 5. The study aimed to provide a cross-sectoral policy guidance focusing on technical and economic regulation and also on security of supply, flexibility, governance of renewable energy sources and climate policy. Categorisation of barriers by type of policy is also shown in the Table below. Recommendations were provided by type of barrier and policy, these have been taken into account in Section 7.

[62] Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU - Final report, https://ec.europa.eu/energy/en/studies/potentials-sector-coupling-decarbonisation-assessing-regulatory-barriers

Table 5 Summary of the regulatory challenges identified in the Sector Coupling Study

Legend
- Technical Regulations
- SoS Regulation and flexibility
- Economic Regulation
- Governance and Renewable climate policy

Barrier Category	Transition	Steady state
1. Immaturity of the relevant technologies	▪ Lack of internalisation of positive externalities from innovation/ learning. ▪ First mover disadvantage – high infrastructure connection costs including 'deep' costs.	n.a.
2. Unlevel playing field due to sector- and technology-specific tariffs and levies	*Anticipation of these barriers by market players is slowing down transition*	▪ Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees. ▪ Power-to-gas facing end-user taxes on electricity.
3. Focus on natural gas in infrastructure regulation	▪ Uncertain access to infrastructure due to uncertain or inadequate quality standards. ▪ Lack of (injection) charging methodology. ▪ Incentive for grid operators to focus on gases compatible with their existing infrastructure ▪ Uncertainty on the regulation of hydrogen (& other innovative new gases) infrastructure ▪ Lack of clear rules for gas curtailment	
4. Uncoupled and uncoordinated infrastructure planning	*Topics listed in the left column are expected to also influence transition phase.*	▪ Risk that suitable storage will not be available. ▪ Insufficient co-ordination on future use of electricity and gas transmission infrastructure –

Barrier Category	Transition	Steady state
		and aligned operator incentives
5. Interoperability between different markets	▪ Possible lack of intra EU co-ordination on standards	▪ Risk of lack of liquid market for sale of heterogenous gases ▪ Lack of coherent cross-border investment framework decommissioning

Value-chain analysis of regulatory barriers to the introduction of new gases

The previous Sections set a conceptual benchmark for the new-gas value chain from production to consumption and on the DSO as a facilitator for this chain to be realized. Penetration of new gases should be promoted and supported by a clear regulatory framework developed either at a national and/or European level or most reasonably at both levels. Nowadays, after almost three decades of continuous efforts, the internal natural gas market has reached a certain level of maturity. Harmonised rules are in place at internal interconnection points, commercial flows are facilitated at all directions and a considerable level of transparency has been achieved. Lack of at least common main principles for new gases at European level may cause disintegration of the internal market with implications to other sectors (e.g. products and goods, appliances). Further, lack of a common European strategy may increase existing divergence between Member States that are already active on the topic and Member States that still have not made any solid commitments or plans for the penetration of new gases.

Many of new-gas technologies are currently non-economically viable. Although addressing support mechanisms is out of the scope of this study it is clear that without a solid commitment facilitated by favourable mechanisms, large-scale deployment shall be challenged. This is even more relevant for hydrogen production facilities were challenges are not only at production level but also at transport. In the CEER public consultation, participants expressed the view that lack of a mandatory target for new gas penetration may inhibit cross border trade while others warned that adoption of a mandatory level may lead to unnecessary refurbishments. Regardless of a legally binding target, lack of solid commitments by Member States towards new gases are expected to delay the process.

As we choose to address potential barriers throughout their value chain, a starting point is at production level. New gases and new-gas production facilities are a relatively novel concept. Lack of clarity on what is meant by the terms "new gases" and "new-gas production facilities" may hinder investment plans and deteriorate decarbonisation commitments. Lack of clarity in the actual role of new-gas facilities can also hinder or at least delay their development. An identifiable gap in this direction is for example the lack of clarity in the role of P2gas as a gas production and/or energy conversion facility. Complex procedures for permitting, lack of clarity on the type of gases accepted for injection into the networks, lack of or non-transparent connection rules and charges, high financial guarantees and payments for the creation of new connections may cause uncertainty to investors and hinder transition to carbon free networks. Available capacity at distribution is not a measure typically available. Lack of rules for determining available capacity may lead to refusals of access.

New-gas production facilities (either biomethane or P2gas) plants are costly investments. Although we identify lack of support as a clear barrier to penetration we shall not address this further as it is beyond the scope of the present study. On the other hand, we note that lack of clear rules on the ownership structure of such facilities can also be a barrier to their development. This is particularly the case regarding the role and involvement of the gas DSOs.

DSOs, typically after decades of moderate investments, are now called to adopt new business models and technologies, act as neutral market facilitators and transform their business to meet the requirements of energy transition. This transformation touches not only on the specific topic of new gases but also upon digitalization, cybersecurity and data handling. Distribution systems are regulated enterprises, cost recovery has been traditionally secured through cost-plus and/or revenue cap methodologies with little focus on innovation. Lack of a legal/regulatory scheme that will guide DSOs to timely and efficiently meet the energy transition challenges may delay network expansions and new connections and ultimately inhibit new gas penetration.

Considerable network development is expected to take place during the transition period not only to connect new-gas production facilities but also to accommodate new-gas injections at times of low demand. Demand for gas is highly seasonal, demand in urban areas is greater than in the countryside and demand for gas during the day is higher than at night. New gas facilities may operate at a continuous mode, as is the case with biomethane production through fermentation, or intermittently as may be the case of P2Gas facilities utilising RES electricity that would have been otherwise curtailed. Substantial imbalances between supply and demand particularly during summer are anticipated. Lack of solid methodologies for the calculation of available linepack, lack of network development plans, lack in transparency in network development and lack of rigid cost-benefit analysis rules may give rise to discriminatory behaviours, delays, non-optimal investments, stranded assets and/or high costs for network expansions to be borne ultimately by end consumers.

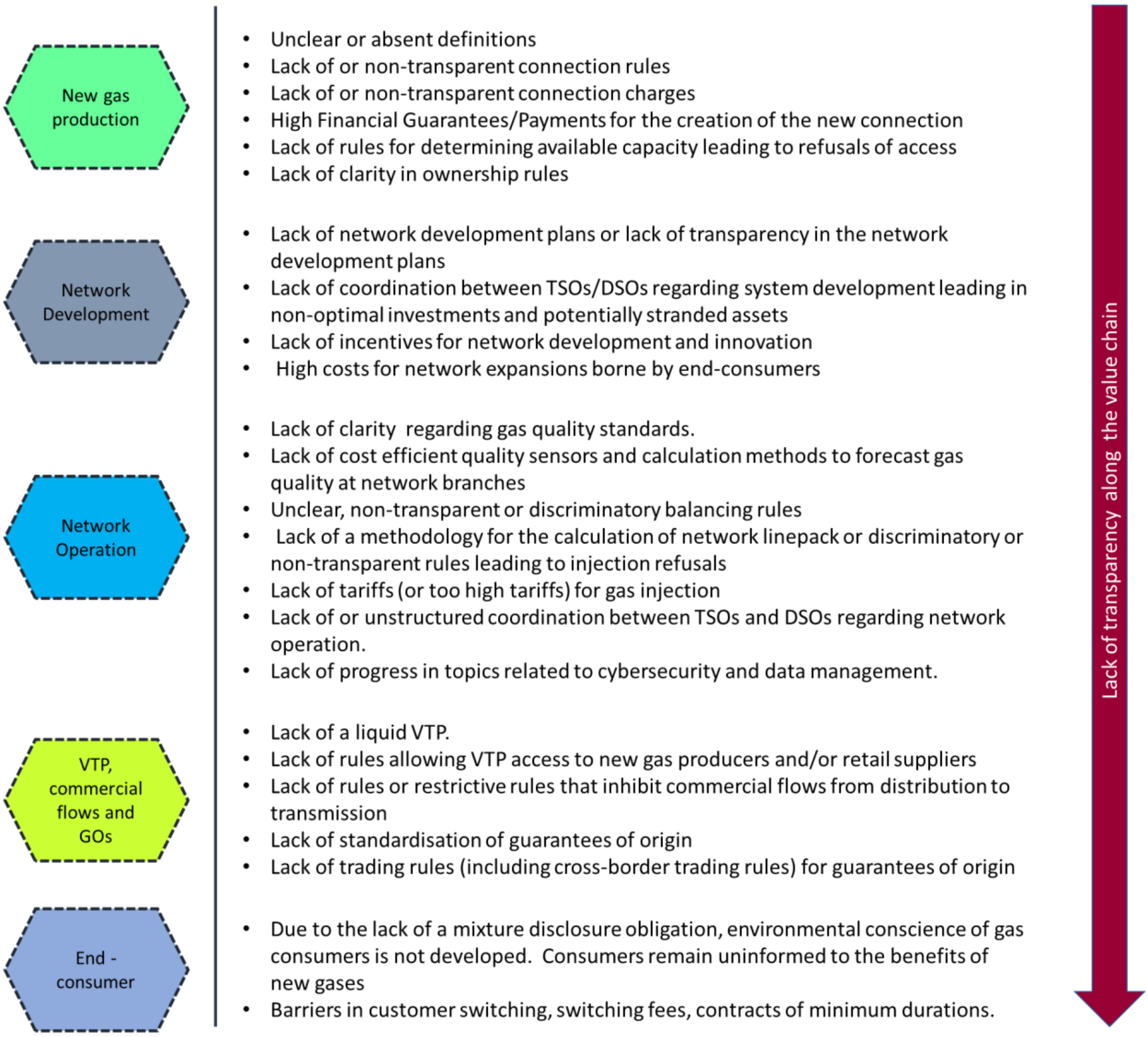
Standardised and well-defined TSO and DSO cooperation for the purposes of network development becomes mandatory. Towards the end of the transition period, cooperation between gas and electricity DSOs is also required in relation to power-to-gas facilities. Further uncertainties such as lack of a methodology for the allocation of costs of gas compressors to be installed between transmission and distribution may also delay network integration.

During energy transition, and at steady state, the DSO is faced with further challenges during everyday operation. Lack of cost-efficient quality sensors and calculation methods to forecast gas quality at network branches, unclear, non-transparent or discriminatory balancing rules, lack of a methodology for the calculation of network linepack or discriminatory or non-transparent rules leading to injection refusals and lack of cost reflective tariffs or discriminatory tariffs may inhibit new gas penetration. Lack of clarity in regarding taxes and levies for P2Gas facilities can also be a clear barrier to entry and operation. Lack of progress in topics related to cybersecurity and data management may also inhibit the modernisation of the DSOs. Cooperation between gas TSOs and DSOs during daily operation is well established however in its current form the DSO is always the taker. Lack of communication protocol among electricity/gas TSO/DSO/new-gas producers to account for the evolving modus operandi and needs can also hinder daily cooperation particularly towards the end of the transition.

The new gas is more expensive than conventional gas and of a variable carbon footprint, Section 2.1. The contribution of new gas towards combating climate change needs to be appropriately quantified and certified. The relevant information should be conveyed to end consumers. Lack of a mixture disclosure obligation upon suppliers may undermine the penetration of new-gases. Lack of standardisation of guarantees of origin may inhibit trade (including cross border trade). New-gas producers shall need to secure bilateral contracts or trade their production at the VTP. Lack of, or discriminatory, rules regarding VTP access may also create a barrier to new-gas-producers. Finally, existing barriers in the retail such as a cumbersome and costly switching process may also inhibit penetration.

Specifically, for hydrogen, we note that conventional hydrogen (otherwise referred to as "gray" hydrogen) has been used by the petrochemical industries for decades and transported through dedicated private pipelines. Introduction of pure hydrogen networks for end-use (e.g. domestic heating) poses further challenges. Clear rules and a proper balance shall need to be stricken between dedicated industrial operation and a potentially regulated service by analogy to natural gas networks. Potential gaps in the regulatory framework, as identified for the remaining new gases, are also applicable to the specific case of hydrogen alone.

Figure 20 aims to provide a summary of topics where absence of regulation, or lack of clarity in existing regulation, may inhibit the penetration of new gases.



.Figure 20 List of potential barriers to the injection of new gases and the role of DSOs within the scope of Directive 2009/73/EC.

National Case Studies: Review of national frameworks and Actions

A number of Member States have already adopted national plans and put in place dedicated regulatory frameworks to alleviate potential barriers as identified in .Figure 20. This Section provides a summary of actions adopted by Austria, France, Germany, Italy and the Netherlands as these countries are comparatively active in their commitments towards new-gas facilitation.

Austria

Overview

Austria hosts 396 biogas plants (as of the end of 2018), with a cumulative capacity of 118 MW[63]. The country ranks 7th in Europe in terms of number of biogas plants installed (after Germany, Italy, France, the UK, Switzerland and the Czech Republic). As shown in Figure 21, electricity generation from biofuels (solids, liquids and biogas) amounts to about 7% of the total electricity generation in Austria. Electricity generation from biofuel plants remains almost unchanged since at least 2013. Electricity from biogas is of the order of 1% of total electricity production.

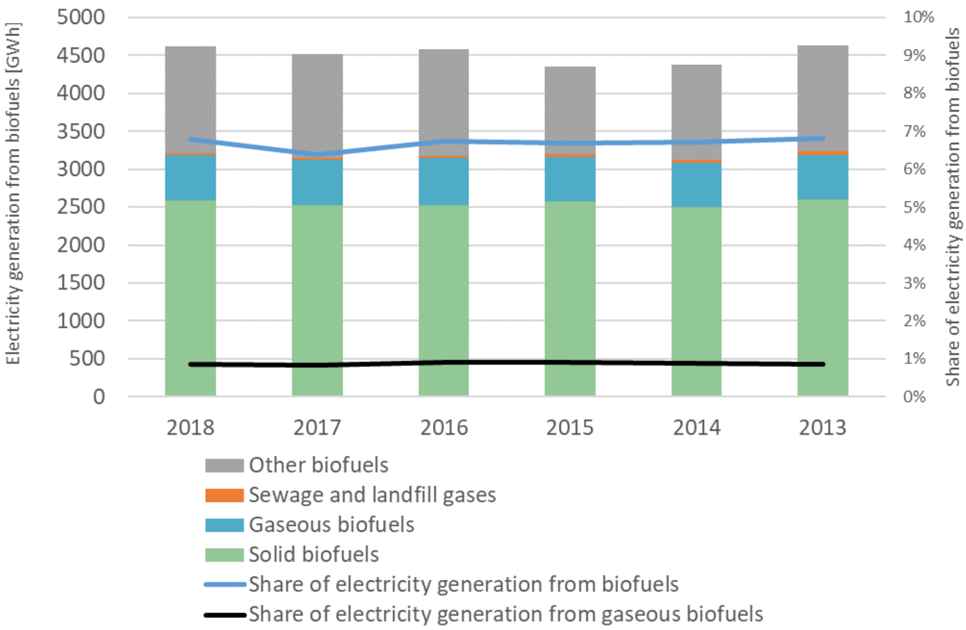


Figure 21 Electricity generation from biofuels including biogas in Austria[64]

As in the case of Germany (see Section 0), the specificity of Austria is its high share of energy crops as input to biogas production and CHP as valorisation pathway. The supporting scheme in Austria is composed of several pillars[65]. The main support is a Feed-in-Tariff for 13-15 years under several conditions which favour agricultural substrates. A tariff premium is granted if heat is used (efficiently) or if the electricity is produced from upgraded biogas. Investment subsidies, which may represent up to 30% of the

[63] Federal Ministry for Sustainability and Tourism, Bioeconomy, A Strategy for Austria (2019), page 64.
[64] Econtrol, Key Statistics 2014-2019, https://www.e-control.at/en/publikationen/statistik-bericht
[65] CEER, Status Review of Renewable Support Schemes in Europe for 2016 and 2017, Geerolf, L (2018) The biogas sector development: Current and future trends in Western and Northern Europe, Master of Science Thesis, KTH School of Industrial Engineering and Management, Division of Heat & Power, Stockholm, Sweden

total costs, are also granted to new CHP plants. A gradual reduction in the feed-in-tariffs has stalled further biogas development. Starting January 2018, FiT for new applicants is limited to plants using less than 30% energy crops and to new bio-CHP plants of an efficiency over 67.5%. Moreover, most efficient existing plants are eligible to a FiT extension of 3 years (subject to selection criteria). As a result, the energy crops share in the production should decrease, while the CHP valorisation should still constitute most of the output.

Injection of new gases into networks is steadily growing, at a rate of circa 15% in the period 2017-2018, Table 6[66]. A favourable injection tariff (in comparison to conventional production plants) is in place and tools to promote new gas injection in natural gas networks are under development (see Section 0). The Austrian Gas Grid Management AG (AGGM) reports on 14 biogas plants, all injecting new gases into distribution systems[67] of production capacity of 36.6MWh/h.

Table 6 Injection of new gases into gas networks in Austria[68]

	2018	2017	2016	2015	2014	2013
Injection of biogas to natural gas networks [GWh]	171	149	131	106	88	53
Total domestic gas consumption [GWh]	**96044**	**100925**	**92822**	**88641**	**83543**	**90170**
Share of Biogas injection to total gas consumption	**0.18%**	**0.15%**	**0.14%**	**0.12%**	**0.11%**	**0.06%**
Annual increase in biogas injection	**15%**	**14%**	**24%**	**20%**	**66%**	**--**

National Framework

Legal acts in support of new gases

Austria has a target of 100% renewable electricity in 2030 and an increase in the share of renewable energy in gross final consumption of energy to 45-50%. For the sake of comparison, we note that actual levels for 2017 were 68% and 32.6% respectively[69].

On December 2018, the Federal Ministry for Sustainability and Tourism presented a legislative proposal for a renewable expansion law from 2020 onwards (Erneuerbaren Ausbau Gesetz 2020 – EAG 2020) and additional actions for the promotion of renewable

[66] https://platform.aggm.at/vis/visualisation/shortcut/Q5r
[67] Ein-/Ausspeisepunkte, Verteilergebiete in Österreich, https://www.aggm.at/files/get/6cf63ccfde24de21333109c2-8e1cda40/EntryExitPoints_DS_Austria_161017.pdf
[68] Draft Integrated National Energy and Climate Plan for Austria 2021-2030, https://ec.europa.eu/energy/sites/-ener/files/documents/ec_courtesy_translation_at_necp.pdf
[69] Bundesministerium für Nachhaltigkeit und Tourismus, Erneuerbaren Ausbau Gesetz Die größten Hits und Herausforderungen, July 2019, https://news.wko.at/news/oesterreich/7_Benedikt-Ennser_EAG---Energiewen-derecht-09-07-2019.pdf

energy including new gases. The proposal is structured across 7 thematic pillars. Three pillars are relevant to new gases[70]. These are listed below.

- **Integrated network infrastructure plan:** This pillar provides for alignment in infrastructure planning between electricity and gas sectors both for transmission and for distribution networks.
- **Greening the gas:** This pillar aims to promote the replacement of conventional gas by biomethane and other renewable gases including hydrogen. It postulates the introduction of a quota system i.e. an obligation for suppliers to include a certain proportion of new gases in their energy mix and preferential dispatching of new gases into the grid.
- **Hydrogen as a driver to innovation:** The development of a hydrogen strategy is a joint initiative between the Federal Ministry of Sustainability and Tourism and the Federal Ministry of Transport. The strategy was launched in 2019 and will be also included in the renewable expansion law.

The proposal also includes 12 flagship projects. Flagship project 7 is dedicated to the promotion of biomethane and hydrogen through four groups of measures[71]:

- **Enablement and support of long-term storage of electricity through hydrogen** (e.g. power-to-gas) and off-set some of the investment cost (Mineral Raw Materials Act).
- **Absorption of excess electricity through the production of hydrogen** Linking funding for renewable energy with the provision of storage capacity.
- **Prioritisation of delivery of hydrogen/biogas to the natural gas network** and development of appropriate instruments to ensure such prioritisation.
- **Boost non-fossil fuels and create legal security for investors through exemptions from taxation for hydrogen and biogas**.

These measures will be implemented through changes several legal instruments such as the Mineral Raw Materials Act, Renewable Extension Act, NaturalGas Tax Act, GasIndustry Act in the period 2-19-2021.

Flagship Project 8 also envisages the design of a number of finding mechanisms.

On 25 September 2019, an amendment to the Green Electricity Act (Ökostromgesetz 2012 – "ÖSG 2012") was adopted. The amendment aims to ensure a stable transitional period until the adoption of the Renewable Energy Expansion Act (Erneuerbaren Ausbau Gesetz). The new provisions foresee increased funding for biogas projects aiming however for electricity generation. It is expected that the proposal for the renewable expansion law and the remaining supporting instruments will be finalised within 2020.

Regulatory Framework for the injection of new gases into networks

The Natural Gas Act (Gaswirtschaftsgesetz[72]) and the Ordinance on Provisions for the Gas Market Model sets the regulatory framework for the connection of biogas production

[70] Bundesministerium für Nachhaltigkeit und Tourismus, Erneuerbaren Ausbau Gesetz 2020 – EAG 2020 Legislatives Vorhaben, mit dem das Erneuerbaren Ausbau Gesetz 2020 (EAG 2020) erlassen, das Ökostromgesetz 2012 (ÖSG 2012), das Elektrizitätswirtschaft- und –organisationsgesetz 2010 (ElWOG 2010), das Gaswirtschaftsgesetz 2011 (GWG 2011) und weitere Gesetze geändert werden sollen.
[71] Federal Ministry of Sustainability and Tourism, #Energy2030, Austrian Climate and Energy Strategy, https://mission2030.info/wp-content/uploads/2018/10/Klima-Energiestrategie_en.pdf
[72] https://www.e-control.at/documents/1785851/1811597/GWG+2011+Fassung+vom+14062017_en.pdf/40c3d3-47-c0fe-7539-fafb-0cdaf87061e0?t=1511873597354, consolidated version 14.06.2017

facilities to networks (transmission and distribution) and rules for operation[73]. Note that the Gas Act uses the term biogenic to refer to new gases without however providing a definition on what types of gases are encompassed by this term. However, the Act is clear that all references to "natural gas" or "gas" also mean biogenic gas produced to meet the natural gas quality standards. Thus, in principle, the legal framework accommodates any kind of new gas as long as it meets the quality standards. Further provisions exist in the Distribution Codes of each DSO[74]. The Austrian Regulator, EControl, recently approved a mixture disclosure obligation set upon suppliers so that end-consumers receive information on the type of gas delivered.

Table 7 provides a summary of all legal provisions outlined above.

Table 7 Rules for the connection and operation of new gas plants to natural gas transmission and distribution networks in Austria

Topic	Responsible entity	Tasks Assigned
General provisions on Quality and Safety		
Quality requirements for biogas injection	Producer	Producers must meet defined quality specifications. Up to 4% of hydrogen injection is currently allowed[75].
Labelling76		
Mixture disclosure obligations	Supplier	Retailers supplying natural gas, biogas, landfill gas or sewage treatment plant gas to consumers in Austria shall show on, or on annexes to, consumers' gas bills (annual statements) their supply mix, taking into account the total amount of gas procured by the supplier for consumers (Section 130 of the Gaswirtschaftsgesetz) . The Austrian Regulator EControl, with its decision no. 275 of January 2019 implemented the legal provision. The obligation (and its implementation) is similar to that already existing for electricity as stemming from Directive 2009/72/EC (and 2018/93/EU). Classification is done according to the three categories (natural gas / renewable gases / gas from other Energy sources). EControl is extending the Guarantees of Origin system to also cover new gases. The regulation is applicable from January 2020.
Definitions		Three categories of gases are defined.

[73] Energie-Control Austria Executive Board Ordinance on Provisions for the Gas Market Model as amended in 2016 (2016 Gas Market Model Amendment Ordinance 2012), Consolidate version https://www.e-control.at/documents/1785851/1811597/GMMO-VO+Novelle+2016_Beschluss_konsolidiert_en.pdf/4c0d35af-5298-42bc-8642-a2c52c4e51aa?t=1473340778473

[74] https://www.e-control.at/recht/allgemeine-bedingungen/allgemeine-bedingungen-gas

[75] AGGM, Netwrork development plan 2019, https://www.aggm.at/files/get/6bfdfe3e2ec2320f8420e580fe06cc15/-LTP19_report_E1_xxxBGG_inkl-annex.pdf

[76] 275. Verordnung der E-Control über die Regelungen zur Gaskennzeichnung und zur Ausweisung der Herkunft nach Primärenergieträgern (Gaskennzeichnungsverordnung – G-KenV), https://www.ris.bka.gv.at/Dokumente/BgblAuth-/BGBLA_2019_II_275/BGBLA_2019_II_275.html

Topic	Responsible entity	Tasks Assigned
		Renewable gases defined as "biogenic gases" according to § 7 4 GWG 2011 (methane, hydrogen and others based exclusively on renewable energy sources). **Decarbonised gas**. The latter is hydrogen obtained through technical processes such as steam reforming or pyrolysis from methane, with carbon dioxide permanently captures and non-emitted (blue hydrogen) **Synthetic gas** which refers to gas originally based on hydrogen and subsequent methanization with hydrogen produced from power-to-gas facilities. From a labelling point of view, it should be noted that electrical energy used can be in principle from both renewable and fossil or other energy sources. If renewable energy sources are used, the synthetic gas produced is considered as renewable gas. If the synthetic gas is obtained from electricity produced from conventional gas, the synthetic gas is considered within the natural gas group.
New Connections		
Injecting Party		The Austrian code offers a common definition for the producers regardless the type of gas injected into the network. An injecting party is a natural or legal person or registered partnership feeding natural gas or biogas into the network at an entry point so that it can be transported.
Capacity Allocation and Capacity Products	System Operator	First Come First Served, Annual firm and interruptible capacity,
Network Connection	System Operator	DSOs are obliged to connect producers of biogenic gas that meet quality requirements. Rules are as with all types of connections. System access contracts may specify any point in time for the connection to become operational, within three years of signing the contract.
Refusal of Access	System Operator	Rules as with all types of connections
Connection Costs	Producer /System Operator (transmission only) System Operator	For transmission, the connection cost is a one-off payment. There is no specific methodology in the tariff regulation. Only a provision that the applicant shall be informed on the individual cost components in a transparent and understandable manner. In cases where connection costs are

Topic	Responsible entity	Tasks Assigned
	(distribution)	borne by system users themselves, the system admission charge shall be reduced accordingly[77]. For distribution there are no provisions for a connection cost in the tariff regulation. There is a network usage charge typically lower than the charge faced by conventional gas producers[78] by factors in the range from 2 to 10.
Second Comer Rules	Network Operator	n.a.
Network maintenance and availability	Network Operator	Rules as with all types of connections
Additional services	Network Operator/Producer	n.a.
Procedure for a New Connection	Network Operator	Applications are received according to a Template included in the Ordinance on Provisions for the Gas Market Model.
Financial Guarantees/Payments for the creation of the new connection	Producer	As with conventional natural gas connections.
Guaranteed minimum entry capacity	Producer	Procedure is common for conventional gas and new-gas producers. Every year, producers of natural or biogenic gas shall set the maximum capacity to be reserved. If a producer of natural or new gas fails to comply with the system operator's call to book capacity within a reasonable deadline to be set by the system operator, the amount of capacity last booked by the producer shall be again booked for the next year.
Estimated time for a new connection	Producer/ Network Operator	Not specified in network code
Delays and Penalties	Network Operator	Not specified in network code

[77] Energie-Control Austria Regulation Commission Ordinance Amending the Gas System Charges Ordinance (2nd 2013 Gas System Charges [Amendment] Ordinance 2017), https://www.e-control.at/documents/1785851/1811-597/01+GSNE-VO+2.+Novelle+2017+2017-09-04_clean_en.pdf/0cc305f1-d33a-add3-d5ac-3ea4d2e55a0a?t=1505478915013 and E-Control Regulation Commission Ordinance Setting the Natural Gas System Charges (Gas System Charges Ordinance 2013), https://www.aggm.at/files/get/ff1610958b98afe330542608e21ae82b/Gas_System_Charges_Ordinance_2013_2.pdf

[78] Verordnung der Regulierungskommission der E-Control, mit der die GasSystemnutzungsentgelte-Verordnung 2013 geändert wird (Gas-SystemnutzungsentgelteVerordnung 2013 – Novelle 2020, GSNE-VO 2013 – Novelle 2020) page 5,
,

Topic	Responsible entity	Tasks Assigned
Operation and Balancing		
Priority of Access	Network Operator	n.a.
Refusal rights for receiving biogas	Network Operator	Refusal on grounds of quality
Balancing	Clearing and Settlement Agent	New gas plants are excluded from the typical balancing process applicable to all other suppliers (Section 26 of the Gas Market Model) and do not sign an operational balancing agreement (which is the case with all other parties). The clearing and settlement agent (CSA) determines deviations between the confirmed schedules and the metered or calculated withdrawals and injections. It receives the required information from the distribution system operators (DSOs) (meter readings, SLP consumptions) and from the distribution area manager (DAM) (confirmed schedules). Settlement is done at the volume-weighted spot price index for the relevant delivery period. New-gas producers are not subject to a ±3% mark-up (depending on whether the producer has a long or short position) unless they have reserved capacity over 10,000 kWh/h. The Ordinance specifies that the invoiced calorific value is used as a base for the calculation and settlement of imbalances. The DSOs have an obligation to use the linepack to operationally balance the system, but no further provisions are included.
Data Exchange		Chapter 2 of the Gas market rules (Version 10 – April 2018) describe in detail the data exchange procedure between the new-gas producer, its balancing responsible party and the operators (DSO, Distribution Area Manager and Clearing and Settlements Agent)[79]
	Balance Responsible Party (BRP)	BRP nominates biogas entries; BRP to DAM if injecting party has authorised BRP to submit schedules☐Nominations and allocations on hourly level.
	DSO and Distribution Area Manager	The DSO notifies the Distribution Area Manager on injections at monthly level (and also calorific values).

[79] https://www.e-control.at/documents/1785851/1811597/SoMaGa_2_Kommunikation+und+Fristenlauf_MG-Ost-_201804_f%C3%BCr+Beschluss_en.pdf/e5bee133-c5e9-0454-b233-1670cc208591?t=1534779303703

Topic	Responsible entity	Tasks Assigned
	Distribution Area Manager, DSO and Clearing and Settlement Agent	Biogas injection schedules and actual metered data on an hourly level
	Network Planning	
Network capacity to accept biogas injection throughout the year	Market and Distribution Area Managers (AGGM)	A plan is developed which also targets distribution systems[80]. The plan includes ▪ Criteria for the sitting of power to gas plants and proposed sitting locations (transmission and Level 1 distribution[81]) ▪ Criteria for the sitting of biogas plants. AGGM, in the plan, states a commitment to prepare a plan for possible sitting locations. Preference is given to locations that are in the immediate vicinity of level 3 network areas (pressures ≤ 6 bars), in which quantities of injected biomethane can be accommodated throughout the year. If the network operator cannot provide firm injection capacity on an annual basis then further investments should be considered.
Investments for injection to upstream networks (e.g. transmission if biogas injection at distribution)	System Operator	n.a.
Network planning (general provisions)	Distribution System Operator	There is an obligation for the preparation of
	Transparency and Reporting	
Report on amount of gas injected to the networks	Network Operator	AGGM reports on biogas injection by geographical area by hour[82]

[80] https://www.aggm.at/files/get/6bfdfe3e2ec2320f8420e580fe06cc15/LTP19_report_E1_xxxBGG_inkl-annex.pdf
[81] Level 1 distribution are lines for the East market area named and listed under § 84 Appendix 1 GWG2011.
[82] https://platform.aggm.at/vis/visualisation/entry_exit/f/2019-12-28T14:00/t/2019-12-28T15:00/rt/individual/gr-/HOUR/g/1201

Indicative hydrogen injection projects

A 6MW hydrogen production facility commenced operations in Linz, Austria in November 2019. The plant is developed under H2FUTURE, a European flagship project. It comprises a large-scale proton exchange membrane (PEM) electrolyser that splits water into hydrogen and oxygen using renewable electricity. The plant is to provide part of the hydrogen required for steel maker Voestalpine. The replicability of the experimental results on larger scales in EU28 for the steel industry are also being studied in the context of the project.

The Federal Ministry of Sustainability and Tourism has also launched the so called "Underground Sun Storage" (USS) project to evaluate different technologies towards increasing penetration of renewable energy sources and utilising different storage options including power to gas. In the context of the USS project, the Hydrogen compatibility of RAG Austria's underground storage facilities was examined. Results show that up to 10% of hydrogen mixtures can be stored in existing underground storage facilities. Beyond this level technical issues may exist subject to further assessments

Summary: Enabling factors and barriers for the injection of new gases in distribution

Table 8 Enabling factors and barriers for the injection of new gases in distribution in Austria

Enabling Factors	Potential Gaps/Barriers
+ The greening the gas initiative, the hydrogen strategy (under development) and the legislative proposals in the context of the Renewable expansion act demonstrate a political commitment towards the promotion of new gases.	– There is no solid support – It is unclear if an operator can refuse a connection on grounds other than quality. – Rules for timely connections are not in place – All existing information is available in national language.
+ The Natural Gas Act (Gaswirtschaftsgesetz) and the Ordinance on Provisions for the Gas Market Model set the regulatory framework for the connection of biogas production facilities to networks (transmission and distribution) and rules for operation.	
+ Injection tariffs for biogas plants are lower by factors of 2 to 10 than injection tariffs from conventional gas.	
+ Rules related to system operation (nominations, allocations) are as with conventional gas	

Enabling Factors	Potential Gaps/Barriers
+ All types of new gases maybe accommodated in transmission and distribution networks if quality specifications are met.	
+ A favourable balancing regime is in place.	
+ A ten-year network development plan that also includes distribution is foreseen. The development plan is produced in cooperation with the respective electricity operators. + The development plan aims to introduce a standardised process for the sitting of new gas plants.	
+ A gas disclosure obligation is in place. Suppliers are obliged to report on the renewable/carbon content of gas delivered to final consumers. A new-gas GO system is under development.	
Publicly available information on the plants is provided by the AGGM	

France

Overview

As of 31 December 2017, 548 facilities were generating electricity from biogas, for a total capacity of 423MW. Electricity generation from biogas was at 1.9 TWh in 2017 i.e. using 5.5 TWh of biogas[83].

By the end of 2017, 44 facilities were injecting biomethane into the natural gas grids. Production capacity at distribution reached 11 TWh per year. At the of 2019, the biomethane injection capacity at distribution level doubled reaching 0.7 TWh/year (88 units). At the end of March 2020, biomethane injection capacity reached almost 1.9 GWh/year (133 units), Figure 22. Total installed injection capacity (transmission and distribution) amounts to 2.4 TWh. About 80% of biomethane producers are farmers.

Total production is at levels substantially below installed capacities[84], Figure 23. Taking into account that gas consumption in 2018 in France was 427,121 GWh[85], it is clear that production levels remain extremely low.

[83] https://opendata.reseaux-energies.fr/explore/dataset/points-dinjection-de-biomethane-en-france/information/?disjunctive.site&disjunctive.departement&disjunctive.region&disjunctive.type_de_reseau&disjunctive.grx_demandeur
[84] https://opendata.reseaux-energies.fr/explore/dataset/production-mensuelle-biomethane/table/?sort=-mois
[85] Eurostat, Complete energy balances, 2018, Value quoted is the gross available energy.

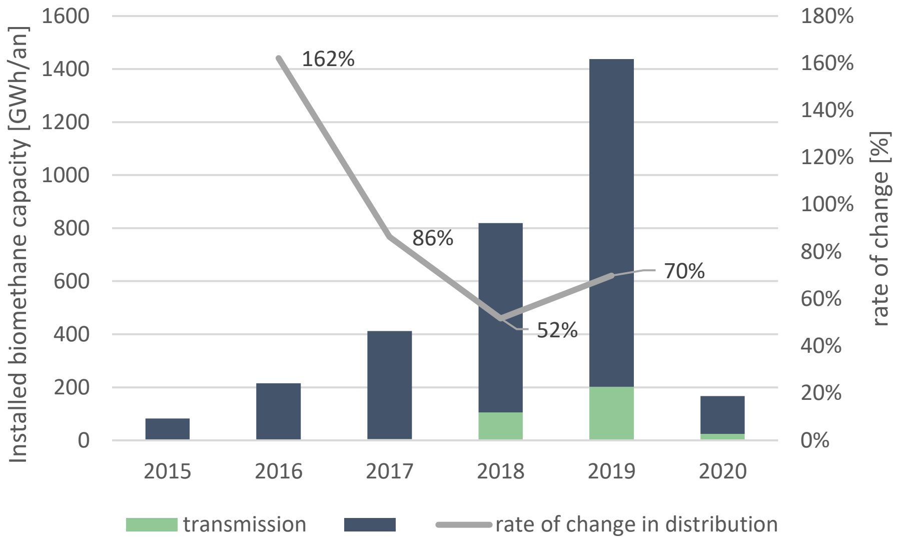


Figure 22 Installed biomethane production capacity in France

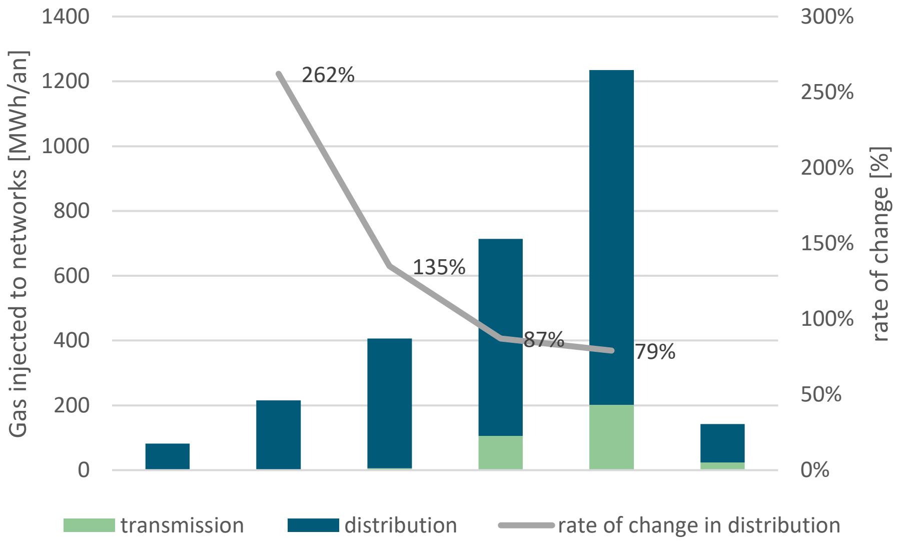


Figure 23 Actual biomethane produced and injected into the networks

France has a solid production target for biomethane of 10% by 2030 as specified in Article L. 100-4 of the Energy Code.

National Framework

Legal acts in support of new gases

The foundation of the current French national climate and energy policy is the Law on Energy Transition for Green Growth (La Loi relative à la Transition Énergétique pour la Croissance Verte - LTECV) adopted in 2015. The LTECV proposes ambitious national targets leading to 75% emissions reductions by 2050.

The long-term targets of the LTECV are implemented through the Multi Annual Energy Programme (PPE or MAEP) and the national low-carbon strategy (Stratégie Nationale bas Carbone, SNBC). This Multi-Annual Energy Plan covers two successive five-year periods: 2019-2023 and 2024-2028 and introduces solid commitments for the injection of biomethane as shown in Table 9.

Table 9 Medium term targets for the use of biogas and biomethane as set by the French Multiannual Energy Programme

Topic	2023	2028
Production of injected bio-methane	8 [*TWh*]	14-22 TWh

The MAEP acknowledges that a main barrier to the penetration of biomethane is its cost, about 10 times more of the cost of conventional gas. To promote penetration the plan foresees two calls to tender, for an annual production objective of 350 GWh HHV/year each, to be launched each year. The calls to tender shall be built on a baseline purchase price trajectory, with the aim of achieving an average of € 67/MWh HHV for the injected bio methane projects selected in 2023 and € 60/MWh HHV in 2028. If this average price is not reached, the total quantities will be reduced not to exceed the public expenditure level targeted. A maximum purchase price trajectory reaching an average of 87 €/MWh HHV for injected bio methane in 2023 and 80 €/MWh HHV in 2028 will also be put in place. Other feed in tariffs are foreseen for smaller installations.

The potential of injecting synthesis gas and hydrogen into networks is also under study but no support is yet provided.

Regulatory Framework for the injection of new gases into networks

A complete set of Rules for network expansions for injection of biomethane into the networks was adopted by the French Regulator CRE in November 2019[86]. Tariffs were updated in February 2020[87]. Main provisions are summarised in Table 10. Detailed provisions are included in the French Code de l' Energie.

The framework design is based on the following main elements:

- A biomethane producer can only sell production to a single buyer.
- Purchase prices are regulated[88].
- A list of last resort biomethane suppliers is also specified.
- Rules target specifically biomethane.

Table 10 Rules for the connection of biogas plants to natural gas transmission and distribution networks in France[89]

Topic	Responsi-ble entity	Tasks Assigned
General provisions on Quality and Safety		
Quality require-ments for biogas injection	Producer	

[86] Délibération CRE du 14 Novembre 2019 portant décision sur les mécanismes encadrant l'insertion du biométhane dans les réseaux de gaz. https://www.cre.fr/content/download/21607/275015
[87] CRE, Deliberation N° : 2020-010, https://www.cre.fr/en/Documents/Deliberations/Decision/equalised-tariff-for-the-use-of-grdf-s-public-natural-gas-distribution-networks
[88] Article R446-2 of the French Code de l' énergie
[89] http: //www.gesetze-im-internet.de/gasnzv_2010/BJNR12611025% 010.html#BJNR126110010BJNG000800000

Topic	Responsible entity	Tasks Assigned
Odourisation and measurements of gas quality and quality of gas at delivery points	System Operator	The Code includes provisions for a second distribution system (second-tier) connected to the first distribution system (first-tier) which is in turn connected to transmission. The second-tier distribution system operator shall make available to the first-tier distribution system operator, upon request, the documents attesting to the compliance of the odourisation of the natural gas distributed with standards in force at the connection points of the biomethane production facilities injected into the second-tier distribution network.
Labelling		
Guarantees of Origin	Producer /Supplier /Delegated Entity for GOs	The Energy Code provides that biomethane injected into natural gas networks, can benefit from a certificate of guarantee of origin, upon request.
New Connections		
Network Connection	System Operator	Connection investments may fall under one or more of the following categories: reinforcements (not giving rise to a financial contribution by producers); connection investments (eligible for pooling between producers); other connection investments (extensions, connections, etc.) giving rise to a financial contribution by producers. CRE has defined the methodology for the evaluation of connection charges[90].
Refusal of Access	System Operator	This right to injection was codified in article L. 453-9 of the Energy Code which states that "[w] hen a biogas production facility is located near a natural gas network, the managers of the natural gas networks carry out the reinforcements necessary to allow injection into the network of the biogas produced, under the conditions and limits **making it possible to ensure the technical and economic relevance** of the investments defined by decree taken after the opinion of the Energy Regulatory Commission. " In June 2019[91], Décret n° 2019-665 specified the rules for assessing technoeconomic relevance and for splitting the cost between producers and operators.

[90] Délibération CRE du 14 Novembre 2019 portant décision sur les mécanismes encadrant l'insertion du biométhane dans les réseaux de gaz.
[91] Décret n° 2019-665 du 28 juin 2019 relatif aux renforcements des réseaux de transport et de distribution de gaz naturel nécessaires pour permettre l'injection du biogaz produit

Topic	Responsible entity	Tasks Assigned
Connection Costs	Shared between network operator and producer	See cell above on network connections
Second Comer Rules	Network Operator	unclear
Network maintenance and availability	Network Operator	No specific provisions in place for biomethane
Additional services	Network Operator/Producer	n.a.
Procedure for a New Connection	Network Operator	To be connected to a gas network, biogas production installations must register with the capacity management register. This register sets up a capacity reservation system, specific to an injection area. Registration in the capacity management register is made when ordering a study (detailed study in distribution and feasibility study in transport), during which the network managers inform producers of the consumption profile of the area to which they plan to connect to and therefore its capacity, and commit to a quote to connect the producer. The connection contract is only signed several months after the delivery of this study. The effective commissioning of the production facility takes place approximately 18 months after the signing of the connection contract.
Financial Guarantees/Payments for the creation of the new connection	Producer	An injection charge is defined in the range of 0 and €0.7€/MWh. The injection charge is location dependent so as to provide locational incentives to producers[92]. The level of tariff also depends on whether injection to transmission is required. The highest level of 0.7 €/MWh corresponding to the case of compression to transmission. Out of the 0.7 €/MWh, 0.65 €/MWh is paid by the DSO to transmission. The French regulator CRE has asked the larger French DSO to CRE collect reliable cost data on pipeline extensions (fixed portion + variable por-

[92] CRE, Deliberation N° : 2020-010, https://www.cre.fr/en/Documents/Deliberations/Decision/equalised-tariff-for-the-use-of-grdf-s-public-natural-gas-distribution-networks

<table>
<tr><th>Topic</th><th>Responsible entity</th><th>Tasks Assigned</th></tr>
<tr><td></td><td></td><td>tion per meter), so that the possibility of introducing a relative incentive may be considered in the future.</td></tr>
<tr><td>Guaranteed minimum entry capacity</td><td>Producer</td><td>Capacity allocation is on a first-come-first-served basis</td></tr>
<tr><td>Estimated time for a new connection</td><td>Producer/Network Operator</td><td>The actual installation of the production facility takes place approximately 18 months after the signing of the connection contract.</td></tr>
<tr><td>Delays and Penalties</td><td>Network Operator</td><td>n.a.</td></tr>
<tr><td colspan="3">Operation and Balancing</td></tr>
<tr><td>Priority of Access</td><td>Network Operator</td><td>No specific provisions have been identified</td></tr>
<tr><td>Refusal rights for receiving biogas</td><td>Network Operator</td><td>No specific provisions have been identified</td></tr>
<tr><td>Balancing</td><td></td><td>No specific provisions have been identified</td></tr>
<tr><td colspan="3">Network Planning</td></tr>
<tr><td>Network capacity to accept biogas injection throughout the year</td><td>System Operator</td><td>CRE has requested network operators to prepare a map with the networks and the potentials for new connections. As outlined above, new connections are divided in different categories related to different costs (and costs borne by operators only or shared between operators and producers). The map is due to be made available Q1-2020.

Investment planning is subject to a technoeconomic assessment as specified by the Décret n° 2019-665 and the Decision of the Regulator of 24 November 2019. Charges to be borne by producers are published as shown below.

<table>
<tr><th>Area color</th><th>Technical-economic ratio</th></tr>
<tr><td></td><td>I / V> € 4,700 / nm3 / h (i.e. € 3.2 / MWh)</td></tr>
<tr><td></td><td>€ 3,300 / nm3 / h <I / V ≤ € 4,700 / nm3 / h (i.e. € 2.2 / MWh <I / V <€ 3.2 / MWh)</td></tr>
<tr><td></td><td>I / V ≤ € 3,300 / nm3 / h (i.e. € 2.2 / MWh)</td></tr>
</table>
</td></tr>
<tr><td colspan="3">Transparency and Reporting</td></tr>
<tr><td>Report on amount of gas injected to the networks</td><td>Network Operator</td><td>CRE has introduced three quality indicators to monitor the response of DSOs regarding new biomethane connections:</td></tr>
</table>

Topic	Responsi-ble entity	Tasks Assigned
		▪ response time for fulfilling requests for detailed studies for biomethane project developers; ▪ number of claims following the connection of bi-omethane installations; ▪ number of claims related to the “Gas conver-sion”. Indicators are reported to CRE on a monthly ba-sis. Biomethane installations are recorded both by the respective operators, in a centralised site[93] and in the Environment and Energy Management Agency (ADEME). Information is also collected by the Ministry of Energy

Indicative hydrogen injection projects

GRHYD of a budget of 15 m€ is coordinated by ENGIE, a global energy and services group and a major French gas supplier. Eleven industrial partners are taking part in the GRHYD in addition to ENGIE, including GrDF. GrDF is the largest dis-tribution system operator in France (over 95% of gas in distribution is distributed by GrDF through a network of over 200,000 km[94]).

The project, launched in 2014, tests the injection of hydrogen into the natural gas distribution grid of the town of Cappelle-la-Grande, a town in the vicinity of Dunkirk in Northern France.

The project is supported by the French state as part of the Future Investments Program run by ADEME (French Environment and Energy Management Agency) and accredited by the Tenerrdis Competitive Industry Cluster.

Its inauguration marks the start of the demonstration with the injection of the first hydrogen molecules into the local natural gas grid, at a level of 6% to begin with (and up to a maximum of 20%), for supplying the 100 households and the health centre’s boiler in the “Petit Village” district of Cappelle-la-Grande.

It consists of two demonstration sub-projects:

- The Hythane® fuel project on an industrial scale. A CNG bus station will be adapted to the hydrogen-natural gas mixture, up to 6% hydrogen and then up to 20%.
- A hydrogen injection project in a natural gas distribution network. A new neighbour-hood of about 100 dwellings in Cappelle-la-Grande will be fuelled by a mixture of

[93] opendata.reseaux- energies.fr/
[94] https://www.grdf.fr/grdf-english/200000km-network-natural-gas-installation,

hydrogen and natural gas, with varying proportions of hydrogen and less than 20% by volume.

The ultimate project scope is to optimize, technically and economically, the sizing of production assets with regard to the volumes and profiles of hydrogen production and consumption, to evaluate the critical links and to propose improvement and optimization solutions, as the case may be.

Its inauguration on June 11, 2018 marked the beginning of the demonstration with the injection of 6% hydrogen into the local natural gas distribution network. On a second stage hydrogen injection reached 10%. Currently it has reached a maximum level of 20%. A total of 100 dwellings and the boiler of a local health centre of the district "The Small Village" of Cappelle-la-Grande are supplied.

Summary: Enabling factors and barriers for the injection of new gases in distribution

Table 11 Enabling factors and barriers for the injection of new gases in distribution for France

Enabling Factors	Potential Gaps/Barriers
+ France has a solid commitment for a 7-10% new gas penetration by 2028. New gas production is supported by a feed-in tariff scheme for smaller installations and a competitive procedure for larger scale facilities + Substantial transparency exists both in terms of installed capacity and biomethane production. Several decisions of the Regulator in relation to new-gases are also available in English. + A methodology for a technoeconomic assessment on various types of network expansions is in place and costs to be borne by producers are published.	– The producer is obliged to contract with a single supplier. It is unclear if VTP access is possible. – Existing rules target specifically biomethane. No provisions for other types of gases are in place.

Germany

Overview

Germany is the leading market for biogas production in the EU. Biogas (incl. biomethane) accounts for 14.2% of the electricity generation from renewable energy sources (RES) in 2018 (circa 32 TWh). The heat supply from biogas amounted to around 16.7 TWht in 2018, which corresponds to about 1.4% of the end energy consumption in the heat sector.[95]

The latest reform of the Renewable Energy Sources Act or EEG (Erneuerbare-Energien-Gesetz) law resulted in a significant reduction of the feed-in-tariffs for biogas plants and

[95] Daniel-Gromke, Jaqueline, Denysenko, Velina and Liebetrau, J. (2019) Germany's Experience with Biogas and Biomethane, in "*Biogas and Biomethane in Europe, Lessons from Denmark, Germany and Italy*" (Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), Etudes de l'Ifri,, Ifri, April 2019.

more importantly in the abolishment of substrate bonus for energy crops and the biogas upgrading bonus for biomethane plants.

To ensure the shift from state support to free market competition in alignment to the EU Guidelines on State Aid, an auction model was introduced within the EEG 2017. Against this background, the development and increase of installed capacity in the biogas sector is currently resulting mostly from plant expansions, adjustments for flexible plant operation as well as newly constructed small manure- and waste-based plants.

Due to expiring subsidies for existing biogas plants in Germany from 2021 onwards, biogas plant operators are faced with new challenges. The upgrade of biogas to produce biomethane offers a promising option within the smart and carbon free energy system that Germany is pursuing.

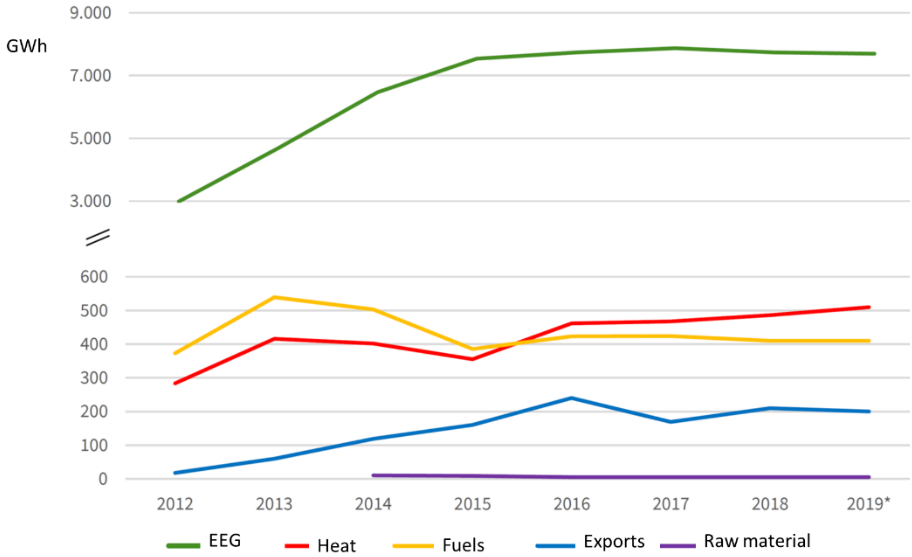


Figure 24 Use of biomethane in Germany[96], EEG stands for biomethane receiving support and fired on site in CHP plants

At the end of 2018, around 8,980 biogas production plants including plants upgrading biogas to biomethane were in operation. Most plants (8,780 plants) that are in operation comprise an on-site electricity conversion of biogas and satellite CHP-units. Just over 200 biogas plants with upgrading technologies produce biomethane. In most of these plants once again biomethane is consumed on site for the production of electricity. A small portion of the biomethane (around 0.3 TWh) is injected into gas distribution networks[97].

About (4%) of the overall biomethane production is used in transport. There are about 120 biogas filling stations in operation and additional 170 filling stations offer a blend of biomethane and natural gas (2017 data).

For the analysis to follow in the remaining of this Section it should be noted that the German Energy Industry Act (Energiewirtschaftsgesetz) defines biogas in § 3, item 10c[98] as "biomethane, gas from biomass, landfill gas, Sewage gas and mine gas, and hydrogen generated by water electrolysis, and synthetic generated methane if the electricity used for electrolysis and the methanation, Carbon dioxide or carbon monoxide each have been proven to be largely from renewable energy sources within the meaning of

[96] dena-ANALYSE: Branchenbarometer Biomethan 2019
[97] https://www.europeanbiogas.eu/wp-content/uploads/2017/12/5.-Hofmann.pdf
[98] https://www.gesetze-im-internet.de/enwg_2005/__3.html

Directive 2009/28 / EC (OJ L 140, 5 June 2009, p. 16)". Thus below, the term biogas refers collectively to several types of new gases.

Key biogas injection figures are summarised in Figure 25. Annual increase in the number of facilities was of the order of 30% in terms of number of facilities connected and almost 40% in terms of injected energy in the period 2013-2014. Since then the number of facilities injecting new gases into the network has radically decrease also reflecting uncertainties on funding schemes, Figure 26.

BNetza reports for 2018[99] that 3 facilities injecting hydrogen of 1.4 GWh/annum are connected to the network. An additional 1.1 GWh of synthetically produced methane is produced by 2 other facilities. The amount of hydrogen and synthetically produced methane equals to just 0.024% of total biomass energy injected into the network. The total amount of biogas injected into gas networks for 2018[100] amounts to about 1%. Both hydrogen and syntenic methane are produced by electrolysis of total connected load of 16.3 MWe.

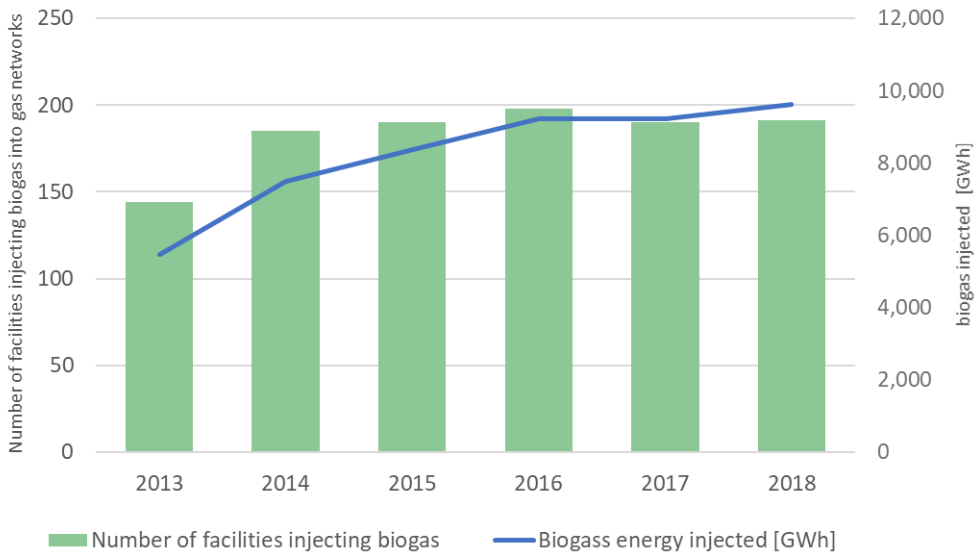


Figure 25 Key figures for biomass injected into gas networks in Germany [101]

[99]Bundesnetzagentur, Monitoringbericht 2019 https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2019/Monitoringbericht_Energie2019.pdf?__blob=publicationFile&v=5

[100] approximate value calculated as a percentage of the amount of biogas injected into networks as reported by BNetza and the natural gas gross consumed also reported in the Monitoring report of the German regulator (928.1 TWh)

[101]Bundesnetzagentur, Monitoringbericht 2019 https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2019/Monitoringbericht_Energie2019.pdf?__blob=publicationFile&v=5 also Monitoringbericht 2018

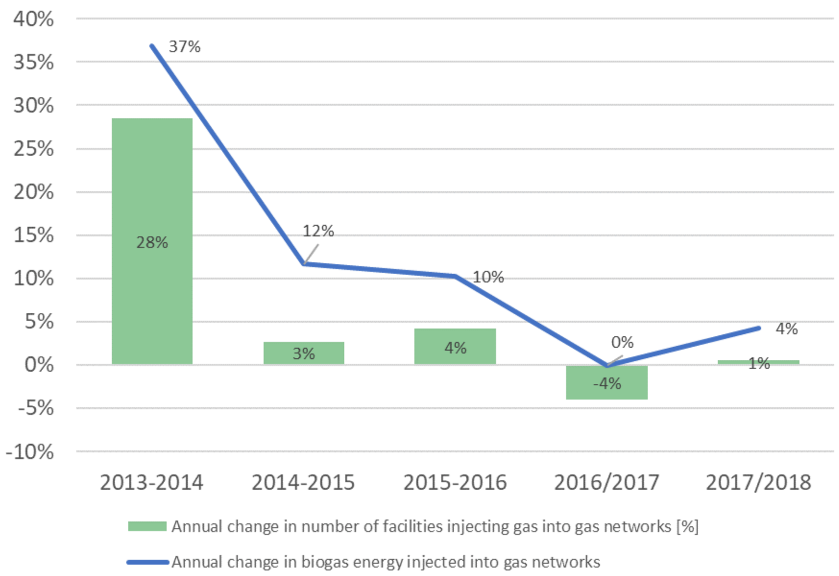


Figure 26 Annual change in the number of biogas facilities connected to gas networks and energy injected.

BNetza reports that the total network cost to accommodate biogas, passed down to end consumers, amounted to 199 m€ in 2018. The respective numbers for 2017, 2016 and 2015 were 184, 172 and 178 m€. The additional cost borne by end-consumers is estimated for 2018 of the order of 0.018 € per kWh of biogas produced. For the sake of comparison, the respective value for 2013 was 0.023 € per kWh pf biogas energy produced.

In its National Energy and Climate Action Plan[102] submitted to the Commission in 2018, Germany notes a penetration projection of 0.6% and 0.2% for biogas and hydrogen in transport respectively. For 2040, indigenous production of biogas is projected at a level of 8% of all energy products[103].

National Framework

Legal acts in support of new gases

Electricity In the electricity sector[104], the current Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz – EEG) is the main policy instrument promoting the production of electricity from renewable energy sources in general including biogas (and biomethane). It has been adopted as a feed-in tariff (FIT) system in 2000. With the latest amendment in 2017 an auction system has been introduced implying public tender procedures for onshore wind, offshore wind, solar and biomass projects in the country's efforts to shift from FIT support renewable energy deployment to a market orientated price finding mechanism. With that, projects are no longer eligible for statuary feed-in tariff remuneration but bid in public auctions organised and monitored by the Federal Network Agency (the German Energy Regulator, Bundesnetzagentur BNetza). The amendment stipulates capacity thresholds for technology deployment in order to control capacity volumes commissioned each year.

[102] https://ec.europa.eu/energy/sites/ener/files/documents/ger_draft_necp_eng.pdf
[103] p. 133 of German NECP
[104] A major part of this section is drawn from the IEA Bioenergy Country report on Germany (2018 update) https://www.ieabioenergy.com/wp-content/uploads/2018/10/CountryReport2018_Germany_final.pdf

The EEG is supplemented by the Biomass Ordinance (Biomasseverordnung – BiomasseV) and the Biomass Electricity Sustainability Ordinance (Biomassestrom-Nachhaltigkeitsverordnung – BioSt-NachV) defining the types of biomass that are eligible for receiving support under the EEG.

Next to the Renewable energy Sources Act (EEG) there is the Combined Heat and Power Act (KraftWärme-Kopplung-Gesetz – KWKG) in place. This Act aims to increase electricity generation from CHP plants, to support the launch of the fuel cell sector and funding for construction and expansion of heating and cooling systems.

The law intends to contribute to an increase in electricity generation from CHP by 25 % by 2020 through the modernisation of existing and construction of new CHP plants. In January 2016, the CHP-Act (KWKG 2016) entered into force. To date CHP plants in Germany have received funding support for cogeneration with a capacity of ≤50 kW and over a period of 10 years. While the eligibility period in the new CHP Act for CHP plants >50 kW with 30,000 full load hours has not changed, for CHP up to 50 kW this amount has been adjusted to 60,000 full load hours.

By 2030, fixed remuneration schemes under the EEG will expire for many existing biogas plants. The central question for existing plants is still which economically viable options exist for the continued operation of biogas plants. If there is no chance for an economic operation of existing biogas plants after the expiry of the feed-in tariff according to EEG, the required investments and maintenance of the existing plants will be deferred, and with the expiry of the EEG tariff, the available plant capacity may decrease.

Heat In the Renewable Energies Heating Act (EEWärmeG, 2008) the German Federal government defined the target of meeting 14% of the heat market demand with renewable energy sources by 2020. In 2011 the renewable energies share was 10.4%. The transformation of district heating to higher percentages of renewable energy can contribute to achieving the targets set. The purpose of the act is to promote renewable energies in the heat sector to achieve a sound management of fossil resources and lower dependency on energy imports. The EEWärmeG aims to facilitate a sustainable development of energy supply and further development of technologies generating heat from renewable energy sources.

In the heating/cooling sector, the main policy measures include a financial subsidy through the Market Incentive Program (Marktanreizprogramm – MAP), a building regulation in form of the Renewable Energies Heat Act (Erneuerbare-Energien-Wärmegesetz – EEWärmeG), as well as further support programs of the public bank KfW and the Energy Saving Ordinance (Energieeinsparverordnung – EnEV). These instruments have allowed for a significant expansion in the use of renewable energies in recent years.

Transport sector In context with the of the point Integrated Energy and Climate Programme (IECP) of the German government, the federal cabinet approved a national ordinance on requirements regarding the sustainable generation of biomass to be applied as biofuel. The Biomass Sustainability Ordinance (BioNachV, 2009) defines minimum requirements for the generation of biomass as biofuels are defined; this ordinance is accompanied and supplemented by the Biofuel Quota Act (BioKraftQuG, 2007).

In January 2015, the German Biofuels Quota Act (Biokraftstoffquotengesetz – BioKraftQuG) introduced a GHG biofuel quota of 6% of GHG reduction in 2020 onwards. The quota system will also be existing post-2020.

Regulatory Framework for the injection of new gases into networks

The Gas Network Access Ordinance (GasNZV, Chapter 6) sets the regulatory framework for the connection of biogas production facilities to networks (transmission and distribution) and rules for operation. Table 12 provides a summary.

Table 12 Rules for the connection and operation of biogas plants to natural gas transmission and distribution networks in Germany[105]

Topic	Responsi-ble entity	Tasks Assigned
General provisions on Quality and Safety		
Quality require-ments for biogas injection	Producer	All costs are borne by the producer. However, there is also a possibility for a portion of the costs to be borne by the system operator. Biogas needs to specify the certain standards provided in the code (worksheets G 260 and G 262 of the German Association of Gas and Water Specialists).
Odourisation and measurements of gas quality	System Operator	
Quality of gas at delivery points	Network op-erator	The network operator is responsible for the qual-ity of delivered gas.
New Connections		
Network Connec-tion	System Operator	See cell "*Procedure for a New Connection*" below
Refusal of Access	System Operator	A network connection cannot be refused with ref-erence to the fact that there are capacity bottle-necks in a network that is directly or indirectly connected to the connection point. If the network operator rejects an application for connection, he must prove the existence of the reasons according to § 17 paragraph 2 of the En-ergy Industry Act[106]. If the connection to the desired connection point is refused, the network operator must at the same time propose to the connectee another con-nection point that realizes the expressed inten-tions of the connectee in the best possible way. The Code states that the network operator is obliged to take the necessary measures to fulfil its obligation outlines above unless implementa-tion of measures is economically unreasonable.
Connection Costs	Shared be-tween net-	The network operator bears 75 percent of the costs for the network connection. The connectee bears the remaining 25 percent of the network

[105] http: //www.gesetze-im-internet.de/gasnzv_2010/BJNR12611025% 010.html#BJNR126110010BJNG000800000
[106] According to § 17 paragraph 2 of the EnWG, operators of energy supply networks can refuse a network connection if they can demonstrate that it is not possible or unreasonable for them to grant the network connection for opera-tional or other economic or technical reasons. The rejection must be justified. At the request of the requesting party, in the event of a lack of capacity, the reasoning must also contain meaningful information about which measures and associated costs for the expansion of the network would be required in order to carry out the network connection; the reason can be requested later. For the justification, a fee that may not exceed half of the costs incurred may be requested, The EnWG foresees that

Topic	Responsible entity	Tasks Assigned
	work operator and producer	connection costs, but for a network connection including a connecting line with a length of up to one kilometre, the maximum is EUR 250,000. If a connecting line exceeds ten kilometres in length, the connectee must bear the additional costs. The network connection is the property of the network operator.
Second Comer Rules	Network Operator	If additional connections are added within ten years after the grid connection, the network operator must distribute the costs as they would have been had the grid been connected at the same time and reimburse connectees for any additional amount paid.
Network maintenance and availability	Network Operator	The network operator must ensure the availability of the network connection permanently, but at least to 96 percent, and is responsible for the maintenance and operation of the network connection. He bears the costs for this. Insofar as it is necessary for the testing of the technical equipment and the measuring equipment, the network operator must allow the connectee or his representative access to the rooms.
Additional services	Network Operator/ Producer	The connectee and the network operator can contractually agree further rights and obligations, services, and compensate each other.
Procedure for a New Connection	Network Operator	The network operator informs the applicant 2 weeks after receipt of the application on the studies that need to be undertaken for the operator to decide on the connection. If additional information is required, the network operator must request this in full of the connectee within one week of receipt of the application. The 2-week period begins from the receipt of all information. If necessary, other network operators are obliged to participate in the studies to determine the connection requirements. The connectee can request that the network operator(s) also carry their analysis considering the assumptions of the connectee. The results of the studies are notified to the connectees. The connectee must be informed of the result of the tests immediately, but no later than three months after receipt of the advance payment. The costs of the studies are borne by the connectee

Topic	Responsible entity	Tasks Assigned
Financial Guarantees/Payments for the creation of the new connection	Producer	25% of the connection costs and cost of connection studies (see above)
Guaranteed minimum entry capacity	Producer	The producer is bound to reserve a certain minimum capacity
Estimated time for a new connection	Producer/ Network Operator	Construction works need to begin within 18 months from the commitment of the producer to a minimum capacity. This timescale is not affected by delays in the construction of the biogas that may occur and are not in the sphere of influence of the connectee. The construction realisation schedule is agreed between the producer and the connectee. Milestones need to be agreed (for example land acquisition, permit acquisition, approval of grid connection work by connectee, placing orders for equipment, actual construction, commissioning time etc). The implementation schedule is submitted to the regulator. The network operator discloses to the connectee all connection costs. The Network Code includes a provision that the efficiency of the system operator must always be preserved.
Delays and Penalties	Network Operator	If the date of commissioning of the system specified in the implementation schedule is exceeded for reasons for which the operator is responsible, the operator's claim to the share of costs for the network connection including the connection line with a length of up to one kilometre to be borne by the connectee is cancelled. All costs are borne by the operator. If the connectee has already made advance payments, the network operator must reimburse them.
Operation and Balancing		
Priority of Access	Network Operator	Network operators are obliged to conclude entry contracts and exit contracts primarily with shippers of biogas and to transport biogas with priority, insofar as these gases are network compatible.
Refusal rights for receiving biogas	Network Operator	Network operators can refuse to feed in biogas if this is technically impossible or economically unreasonable. The feed-in cannot be refused with

Topic	Responsible entity	Tasks Assigned
		the indication that there are capacity bottlenecks in a network directly or indirectly connected to the connection point, insofar as the network's technical-physical capacity is given.
Balancing		Market area managers obliged to offer expanded balancing for the entry and exit of biogas
Special biogas balancing group contracts		▪ The balance sheet for biogas balancing group contracts for twelve months (accounting period) must be balanced (as is the case with conventional natural gas contracts but under a flexibility arrangement as shown below) ▪ A flexibility of ± 25% is provided. This flexibility refers to the cumulative deviation of the amount fed into the network to the amount withdrawn within the accounting period. ▪ The market area manager and the balancing group manager can agree on an initial accounting period of less than twelve months (short accounting period). ▪ Positive final balances from a previous accounting period can be transferred to the following accounting period. ▪ Differences exceeding the flexibility must be compensated. ▪ Proportionally, only those costs may be invoiced that are necessary to compensate for the differences that remain after balancing all balancing groups managed by a market area manager. ▪ The standard provisions for natural gas balancing groups are not applicable. ▪ The biogas balancing group manager pays the market area managers a fee for the extended balancing service of EUR 0.001 per kWh for the use of the flexibility framework. The service is monitored by BNetza within the lines of §35, par 1.(7)s of the Energy Industry Act.
Transfer of quantities between balancing groups		Transfer of quantities from natural gas balancing groups to biogas balancing groups is not allowed.
Information exchange		Before the start of each balancing period, the balancing group manager informs the market area manager about the expected entry and exit quantities and their scheduled distribution for the balancing period.

Topic	Responsi-ble entity	Tasks Assigned
		Network Planning
Network capacity to accept biogas injection through-out the year	System Operator	The network operator must carry out all economi-cally reasonable measures to increase the capac-ity in the network to ensure all-year feed-in and to ensure the ability of its network to meet the demand for transport capacity for biogas.
Investments for injection to up-stream networks (e.g. transmission if biogas injection at distribution)	System Operator	The network operator is obliged to ensure the ability of the network to transport biogas further upstream as well as the installation of additional facilities such as de-odourisation and drying of the biogas. The network operator must check to what extent the feed-in of biogas can be achieved without or with reduced admixture of liquid gas under eco-nomically favourable conditions, considering fu-ture biogas feed-in.
Network planning (general provi-sions)	Distribution System Operator	Art 15 of the EnWG (also applicable to distribu-tion) specifies that operators should ensure that their networks have a long-term ability to meet demand in transportation services. No obliga-tions for a 10-year development plan are in place.
		Transparency and Reporting
Report on amount of gas injected to the networks	Network Operator	The network operator immediately reports the feed-in quantities in energy units that it has taken over from the shipper to the relevant con-nectee, the balancing group manager and third parties designated by the connectee.

Indicative hydrogen injection projects

In Falkenhagen, at the north east of Germany Uniper Energy Storage has constructed the world's first demonstration plant power to gas plant107. The project, originally funded by the EU research project STORE&GO, started in 2014 using electricity generated by wind turbines to produce 360 Nm³/h of hydrogen. Hydrogen was fed via a 1.6 km hydrogen pipeline into the natural gas grid operated by the German transmission system operator ONTRAS Gastransport GmbH.

. In May 2018, following the completion of the installation of a methanation stage, synthetic natural gas - methane – is now being fed into the grid. Synthetic methane is produced from hydrogen and CO_2. Nowadays. the plant produces up to 1,400 cubic meters of synthetic methane (SNG) per day, which corresponds to approximately 14,500 kWh of energy

With this amount of energy, 200 medium size passenger CNG cars could drive about 150 km per day. The methanation is designed for continuous operation and constantly achieves high quality of feed.

A 10MW PEM electrolysis plant is also under construction at Shell's Rheinland refinery in Wesseling, Germany. The plant is developed in the context of REFHYNE a project funded by the European Commission's Fuel Cells and Hydrogen Joint Undertaking (FCH JU)108.

Summary: Enabling factors and barriers for the injection of new gases in distribution

Table 13 Enabling factors and barriers for the injection of new gases in distribution for Germany

Enabling Factors	Barriers
+ The Energy Industry Law (EnWG) includes a broad definition of biogases. This definition incorporates biomethane, synthetic gases, hydrogen and other gases produced from renewable sources – thus in principle a wide variety of renewable gases may be injected to German gas networks subject to their meeting quality requirements. + The Gas Network Access Ordinance, which sets connection and operation rules for biogas injection, includes common rules that also accommodate several renewable gases	– Other gases of reduced carbon footprint but not of a renewable origin cannot be accommodated at this time. – The positive investment trend has decreased in the period 2014-2018 reflecting market uncertainty in the funding mechanisms for new installations. – Publicly available information is limited and shared by various entities (Dena, BNetza). A database which provides information on plants connected to gas networks (maintained by Dena) is only upon subscription.

107 https://www.uniper.energy/news/methanation-plant-in-falkenhagen-starts-operation-and-supplies-synthetic-methane--another-step-towards-a-successful-energy-transition/
108 https://refhyne.eu/about/

Enabling Factors	Barriers
+ A favourable legal framework regarding feed-in tariffs promoted the development of biomethane facilities in the period 2013-2014 (Figure 16).	– All existing information is available in national language.
+ Rules to ensure that the system operator does not refuse a connection are in place.	
+ Connection charges are shared between Producers and the remaining network users at a pre-specified proportion of 25%/75%	
+ Costs for new connections are notified to the regulator. BNetza in their annual monitoring report publish the additional costs borne by network operators for the connection of biogas plants and the cost per kWh delivered to each end-user.	
+ Rules for timely connections are in place	
+ There is priority for biogas injection over conventional gas to meet demand. The network operator cannot refuse to uptake biogas except on ground of quality and pressure.	
+ A favourable balancing regime is in place	

Italy

Overview

Italy is the second biogas market in Europe after Germany in terms of number of plants, and the third in terms of biogas production (2.2 bcm/year), after Germany and the United Kingdom[109].

The sector evolved in three periods driven by relevant changes in feed-in-tariffs (FiT).

The biogas industry took off in 2008. The period from 2008 to 2012 was characterized by a rapid growth in biogas plants installations. Over 1000 plants of capacity of around 900 MWel (1% of total generation) [110] were installed. Progress was due to a favourable FiT ("tariffa onnicomprensiva") of 288 € per MWh of electricity produced. For the sake of comparison, we note that the day-ahead electricity price at the Italian Energy Exchange (GME) was of the order of 70 €/MWh for mainland Italy and of the order of 100-

[109] European Biogas Association (EBA), Statistical Report 2017, February 2018, available at: https://european-biogas.eu; EurObersv'ER, Biogas Barometer 2017, available at: www.eurobserv-er.org

[110] Total generation capacity of end of 2012: 124 GW, Source Annual Report to the International Agency for Cooperation Between National Energy Regulators and the European Commission on the Activities and Duties of the Italian Regulatory Authority for Electricity and Gas (2013)

110 €/MWh for Sicily[111]. Overall the Italian Power Exchange registered for 2012 an average price of 75.53 €/MWh[112] .

In the period from 2013 to 2017, the Italian biogas support scheme entered its second phase and the FiT tariff was reduced although the duration of support received by power plants was extended from 15 to 20 years. The levels of feed-in-Tariffs depended also plant size (the smaller the biogas plant, the higher the subsidy) and feedstock type (the more by-products or organic waste, the higher the subsidy). A ranking system for the new biogas plants ("registri") was also introduced. The end of 2017 saw[113] a total of 1555 biogas plants of total capacity of 1345 MWe.

The third period which started in 2018 is being shaped by the provisions of the Biomethane Decree analysed in the next Section. In the period 2016-2019 there has been a considerable growth in new connections of biomethane plants to the transmission network, Table 14. Data for just two months within the Gas Year 2019/2020 (October/November 2019) also show a spectacular increase both in terms of new connections and Biomethane Entry Point Capacity.

Table 14 Progress in biomethane connections at transmission level[114]. Data for the Gas Year 2019/2020 until November 2019

Gas Year	Number of connections	Entry Point Capacity [Sm^3/d]	Annual increase in no. connections [%]	Annual increase in Biomethane Entry Point Capacity [%]
2019/2020 (2-month data)	37	764,232	16%	9%
2018/2019	32	703,356	39%	16%
2017/2018	23	607,528	229%	304%
2016/2017	7	150,376		

Further advances are expected in the forthcoming years. In the country's National Energy and Climate Action Plan submitted to the Commission in 2018, a goal of 8% in the penetration of advanced biofuels in final energy consumption in transport is noted for 2030. About 75% of the target for advanced biofuels will be attained through the use of advanced biomethane (0.8 Mtoe) and 25 % through the use of other advanced biofuels (0.26 Mtoe).

The next paragraphs provide an overview of the current national legal and regulatory framework.

Current National Framework

Legal acts promoting new gases

On 2 March 2018, the Minister of Economic Development and the Ministers of Environment and Agricultural Policies signed decrees for the promotion of the use of biomethane

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[111] See for example http://www.mercatoelettrico.org/It/WebServerDataStore/MGP_ReportGiornaliero/20121010MgpReportGiornaliero.pdf
[112] Annual Report to the International Agency for Cooperation Between National Energy Regulators and the European Commission on the Activities and Duties of the Italian Regulatory Authority for Electricity and Gas (2013)
[113] Maggioni, L., Pieroni, C., Pezzaglia, M The biogas and biomethane market in Italy Evolution of the Italian market: from biogas for the production of electricity to biomethane as biofuel https://www.gas-for-energy.com/fileadmin/G4E/pdf_Datein/g4e_2_18/02_fb_Maggione.pdf
[114] Snam Rete Gas, New Activation Points and Accepted Biomethane Connection Offers, list updated monthly, https://www.snam.it/en/transportation/Online_Processes/Capacita/information/transportation-capacity/Transportation_capacity/Capacity_entry_exit/01c/01c_elenco.html

in the transport sector. With the Decree (Biomethane Decree), Italy set the objective of 10% consumption of renewable energy by 2020 in the transport sector and a national sub-target for advanced biomethane and other advanced biofuels of 0.9% by 2020 and 1.85% by 2022. The mechanism is funded by sales of petrol and diesel. It is also required that biofuels, most importantly imported biofuels (biodiesel), are replaced with biomethane produced in Italy, in order to promote the construction of plants for the treatment of urban waste.

Due to the Ministerial Decrees of 2018[115], the biomethane market is now experiencing a new growth. It is useful to note that in its preamble, the Biomethane Decree makes specific reference to paragraph (26) of Directive 2009/73/EC on the obligation of Member States to take concrete measures to encourage wider use of the biogas and gas from biomass and that producers of these types of gases should obtain non-discriminatory access to the gas systems. Grids have a wide definition in the Decree: they include all types of networks: transmission, distribution systems and also transport systems with cylinder trucks, and natural distributors for transport (CNG and LNG stations), even if not connected to the main networks. The ultimate focus of the Decree is on transport with networks being the means for making decarbonised gas available to the transport sector.

The Decree allocates funds of €4.7 billion to installations, new and existing ones undergoing upgrades to biomethane and becoming operational within the year 2022 at the latest. The fund covers a maximum yearly production of 1,1 bcma. Within this scheme, gas retailers are obliged to include biofuels in their offer and show a preference to biofuels produced in the national territory. To better understand the level of biomethane to be receiving support under the Biomethane Decree, note that current Italian indigenous production of conventional gas is around 4.5 bcma[116] while annual national gas consumption exceeds 70 bcma.

The biomethane promotion scheme is based on the sale of the so-called CIC certificates (Certificati di Immissione in Consumo di biocarburanti) allocated to biomethane producers by GSE (Gestore dei Servizi Energetici[117]). CICs are bought by suppliers of transport fuel subjected to a mandatory blending quota. The number of CICs that these suppliers are obliged to hold is determined every year and specified in the Decree. The Decree further specifies that 75% of the sub-target for advanced biofuels must be met with biomethane and the remaining 25% with must be met with other advanced biofuels[118]. It stipulates for biomethane to be ultimately sold in a virtual point. This can be the case for example for plants connected to the distribution network where biomethane, for commercial purposes, may be considered as delivered at a virtual entry point (PIV) to transmission subsequently sold to downstream suppliers at the virtual trading point of the transmission system operator Snam Rete Gas (PSV), either as a result of a bilateral transaction or though the organised gas market of GME. Figure 27 is a schematic prepared by Snam showing a potential structure of the gas market following the Biomethane Decree.

[115] https://www.gazzettaufficiale.it/eli/id/2018/03/19/18A01821/SG
[116] source EUROSTAT, Table **nrg_bal_c**
[117] , National Agency in charge of managing all the support schemes for renewables deployment
[118] "Italy – 2018 Update, Bioenergy Policies and Status of Implementation", IEA Bioenergy, IEA, September 2018, available at: www.ieabioenergy.com., Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), "Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy", Etudes de l'Ifri, Ifri, April 201

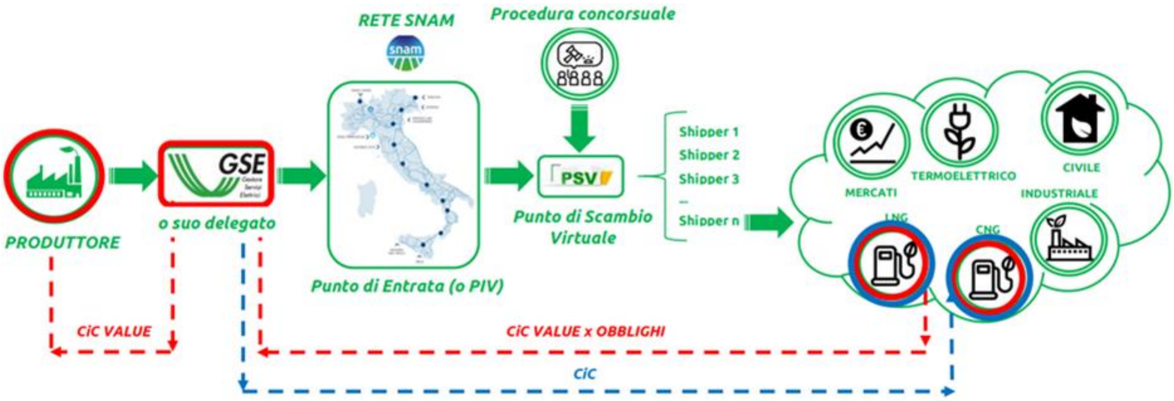


Figure 27 Visual representation drafted by the Italian Transmission System Operator Snam Rete Gas of a potential biomethane market based on the provisions of the Biomethane Decree. The virtual point of entry (PIV) of gas from distribution networks is identified[119].

The definition of advanced biomethane refers to the use of certain feedstocks[120], such as waste, by-products and integration crops, crops that do not cause an Indirect Land Use Change (ILUC) for their production as provided for in the new EU renewable energy directive (2018/2001/EU, RED II). Overall, the Decree puts strong emphasis on the sustainability of biofuels which are certified.

The Decree includes a specific favourable support scheme for advanced biomethane to be used for transport, including agricultural machinery, fishing vessels and inland navigation. However, although focus is on transport the Decree is clear that only biomethane introduced into the natural gas network is considered (with the network however being broadly defined). Overall however it is clear that the Decree also seeks to promote network injection.

For the first ten years of operation of their biomethane plant, producers can decide to sell the biomethane produced to GSE, obtaining the Day Ahead gas market price as traded in the Italian energy exchange GME, minus 5%. Producers will also obtain a premium corresponding to the value of the CICs, set at € 375/10 GCal (≈ EUR 44/MWh)for biomethane or at € 375/5 GCal of advanced biomethane (≈ EUR 87/MWh). The producers can alternatively decide to trade directly their biomethane without the intervention of GSE, obtaining only the premium of EUR 375/CIC. Following this ten-year period, producers have access to the ordinary method of valuing CICs, namely through the private sale to parties. In order to help CIC trades the Decree includes a provision for GME (Gestore dei Mercati Energetici, the Energy Market Operator) to set up an organized exchange platform. This platform is not yet available. Currently, operators can exchange CICs through a dedicated platform created by GSE (BIOCAR).

Biomethane producers (also in LNG and CNG forms) are entitled to an increase in the number of GICs by a factor of 20% to 70% of the value of the cost of construction of the same natural gas distribution plant with a maximum value of 600,000 euros per plant.

The Decree also provides for issuance of guarantees of origin (GO) for biomethane not meant to be used for transport (and thus not benefiting from the support scheme described above). These GOs may be also used by participants in the emissions trading

[119] https://www.snam.it/export/sites/snam-rp/repository-srg/file/it/business-servizi/dialoga-con-noi/news/20180426_Biometano/4_-_2018-04-18_-_Connecting_Biometano_-_Accesso_al_servizio_di_trasporto_gas.pdf, slide 20.
[120] listed in Annex 3 of Ministerial Decree of 10 October 2014

system (Directive 2003/87/EC) towards reducing their obligations to counterbalance their emissions through European Union Emission Allowances (EUAs), as provided by Regulation (EU) 601/2012, concerning monitoring and reporting of greenhouse gas emissions.

The supporting framework as outlined above focuses on biomethane. There is no equivalent for other new gases, for example hydrogen.

Regulatory Framework for the injection of new gases into networks

The Italian Legislative Decree no. 164/00 (known as the "Letta Decree") clarifies that "the rules concerning natural gas set by the Decree also apply in a non-discriminatory also to biogas and gas deriving from biomass or other types of gas, to the extent that these gases can be injected into the gas system natural and transported through this system without posing technical problems or security", as provided for in Article 1, paragraph 2 of Directive 2009/73/EC. Through a number of Decrees since 2011, ARERA, the electricity, gas and water regulator of Italy, has been assigned the further responsibility of adopting specific provisions "regarding the technical and economic conditions for the connection for biomethane production plants to natural gas networks".

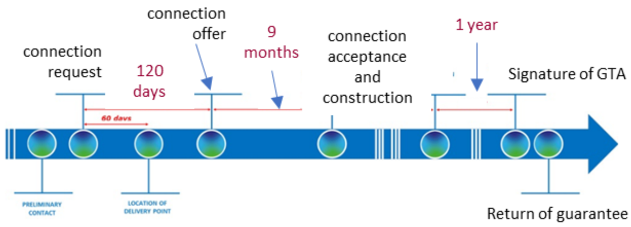
In 2015, with Resolution 46/2015/R/gas, the Italian Regulator, approved rules for the connection on biomethane plants to natural gas transmission and distribution networks. The main elements of the decision are summarised in Table 15.

Table 15 Summary of rules for the connection of biomethane plants to natural gas transmission and distribution networks in Italy (AEEGSI Resolution 46/2015/R/gas).

Topic	Responsible entity	Tasks Assigned
General provisions on Quality and Safety		
Safety and technical efficiency of the network	System Operator	The Network Operator ensures that the biomethane entering the network at the new entry point corresponds to technical specifications and prerequisites on safety.
Odourisation	System Operator	The distribution operator is responsible for the odourisation of biomethane
Compliance with quality specifications, pressure and ability for odourisation according standards	Producer (for gas injected from the production facility to the network). System Operator for gas injected into the network from cylinders.	It is the responsibility of the producer to ensure that biomethane introduced into the network complies with quality specifications, pressure or capacity constraints. The producer also ensures that the injected biomethane can be odorized according to the standards and does not have such features to cancel or cover the effect of odorizing substances. [*The manufacturer of biomethane sends monthly updated data to the GSE measures and analyses carried out in compliance with the criteria set out in quoted relationship, provision included in the Decree of 2018*] The biomethane producer is responsible for the installation and maintenance of the measuring systems. [for cylinders however

Topic	Responsible entity	Tasks Assigned
Quality and pressure Specifications	System Operator	The network manager defines and publishes the quality and pressure specifications for the input of biomethane in its own network. However, at the time, due to the lack an EU standard (now EN 16723-1, released in 2017) there was a standstill in the definition of certain quality specifications. Only biomethane produced from the anaerobic digestion of organic products and by-products was eligible. This issue has been now resolved.
	New Connections	
Connection Point	System Operator	The connection point is identified by the system operator considering the hourly profiles.
Refusal of Access	System Operator	Denial of access may be because the injected gas does not meet technical specifications or incompliant to safety standards. Technical specifications may also include quality standards and pressure levels. <u>The refusal is notified to the regulator.</u>
Procedure for a New Connection and content of a Connection request	System Operator/ Producer	The procedure includes the following steps: 1. The producer submits a connection request. 2. The Operator carries a feasibility study, identifies the entry point and obtains a cost estimate which is notified to the producer within 120 days from the receipt of the connection request. If the producer accepts the cost, then the guarantee is released to meet the connection expenses. The Regulator decision specifies the content of the application and specifies a standardised response to be provided by the network operator to the applicant. In its response, the operator also specifies the portions of the connection system that can be made by the applicant and the schedule for the realization of the connection. The procedure for new connections does not discriminate between biomethane and conventional gas Entry Points.
Estimated time for a new connection	*[not included in the ARERA decision but estimated*	The Italian TSO Snam Rete Gas provides online the following timeline for the realisation of a biomethane connection[121].

[121] https://www.snam.it/en/transportation/Online_Processes/Allacciamenti/procedure-module/new-delivery-biomethane-points/biometano.html

Topic	Responsible entity	Tasks Assigned
	here to provide an indication]	 *The timeline shown here is applicable to connections to transmission.*
Delays and Penalties	Network Operator	In case of delay by the operator in work realization, an automatic compensation is provided. The compensation equals 35 euros / day for every working day late. In the event that the delay exceeds 60 working days, the applicant may report to the regulator requesting for measures to be taken. Additional provisions to address delays (such as increase in the level of compensation) are also in place.
Financial Guarantees, application fees	Producer	A financial guarantee (2,000 euros) is submitted together with the connection request. This amount is subject to escalation (based on the Harmonised Index of Consumer Prices in Italy)
Connection Fee	ARERA	The connection fee is calculated from the following formula: $$C = [I - T \cdot \sum_{t=1}^{n} \frac{1}{(1+i)^t}] \cdot \alpha$$ Where I is the investment cost for the construction of the grid connection system, evaluated according to technical minimum solutions, expressed in euros. T is the expected average annual tariff revenue deriving from the application of the tariffs for the use of the network calculated with reference to the delivery points. In the case of connections to the distribution network, the T parameter assumes a value of zero; i is the is the rate of return on invested capital, n the investment lifetime (equal to 50) and α a reducing coefficient equal to 0.8. The connection fee may be paid within a 20-year period. An instalment formula is also included.
Second comer rules	System Operator	Second comer connection rules are also included, so that if in a period of the first 10 years one or more parties connect on the same pipeline, the

Topic	Responsible entity	Tasks Assigned
		network operator returns a portion of the instalments already paid to the producer who initiated the connection.
Operation and Balancing		
Tariffs for use of Biomethane Entry Points	System Operator	Applicable tariffs are the same to those paid by producers of conventional gas.
Measurement system installation and maintenance obligations	Producer	The producer is responsible for measuring quantity and quality of gas produced and also for the maintenance of measuring equipment. The decision of ARERA provides specifications on the measurement systems such as daily availability of measurement data relating to quantities with hourly detail) automated systems with data downloading functionalities etc. The network operator has the right to access the measurement systems.
Collection, validation and registration of quantity and quality measurements and availability of measurements	System Operator	In addition to collecting the measured data, the system operator also makes available collected data. The network manager stores the data relating to the quantities and to the quality of the biomethane introduced into the network for a minimum period of 10 years
Balancing		No specific provisions included in the ARERA decision
Network Planning		
Network Planning		No specific provisions included in the ARERA decision
Transparency and Reporting		
Transparency	System Operator	The network operator identifies and makes publicly available a) the quality specifications for biomethane to be placed on the network; b) the criteria for assessing the admissibility of a connection request; c) the criteria for the location of the entry point; d) the procedure for examining the connection request; e) the criteria for carrying out work by the applicant for the connection;

Topic	Responsible entity	Tasks Assigned
		f) the technical standards relating to the construction of the connection system to the network. Following the 2015 modification of its network code to accommodate biomethane plants, Snam Rete Gas is obliged to publish in its website a list of connected facilities and the respective connection capacities on a monthly basis.

Table 16 Information made available online by the Transmission System Operator

Transparency and Reporting (in practice)	
Information related to a connection	▪ Connection Application ▪ Technical Information ▪ Timeline ▪ Guarantees
Information related to progress in the connection of biomethane facilities	▪ List of connected facilities and connected capacities updated monthly Actual production is not reported neither in the site of Snam nor in GSE who is the authority also responsible for data collections for plants under the incentive scheme.

The decision of ARERA includes additional provisions to "track" the gas injected into the networks to determine whether it is eligible to receive support according to the Biomethane Regulation. The decision distinguishes between gas injected into the network without and without a destination clause, direct connections to consumption and also whether the injection is from a cylinder or intended for high efficiency cogeneration as support mechanism varies. There is also a distinction between biomethane produced from one or multiple biogas plants, Figure 28. The decision also includes some provisions of transparency and reporting obligations of biomethane producers to GSE.

In 2016, the Snam adapted its network code to allow for the injection of biomethane. No similar updates for the distribution companies have taken place to date[122].

On 29 January 2019, by its 27/2019/R/GAS Decision , ARERA approved a new set of rules for the connection of biomethane plants to transmission and distribution networks. The rules include alignment of the quality specifications to the standard CEN EN 16726 on gas infrastructure and quality of gas and some additional provisions for the implementation of the Biomethane Decree. The remaining conditions regarding access to the network remain unchanged.

The 2019 ARERA decision was placed into public consultation prior to its adoption. We reviewed the responses from the market with emphasis on topics related to distribution.

[122] The last update of the Network Code for Distribution took place in 2010, https://www.arera.it/allegati/gas/codicerete/crdg.pdf

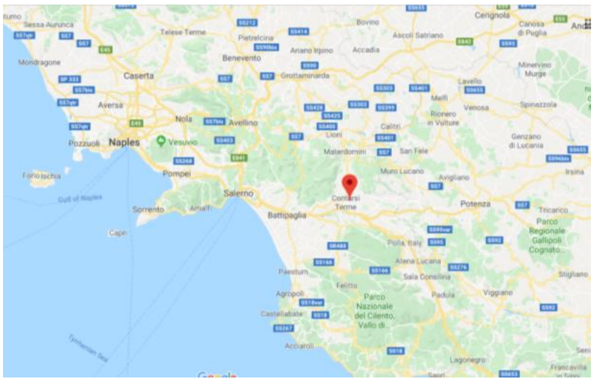
Indicatively, a number of topics identified by the DSOs that participated in the consultation are listed below:

- Concerns for pure mixability of new gases with conventional gas in distribution networks as distances between production and consumption can be short.
- Requirements for clarity in the role of the distribution system operators
- Requests to limit of liability between producer and DSO to be fixed upstream of the odourisation plan
- Requirements to specify the roles of the various parties involved also in the commercial chain
- Need to specify the form of communication between the parties involved
- Need to specify that injection of biomethane should comply with minimum pressure requirements.
- Concerns that DSOs cannot firmly commit to the quantities of gas to be absorbed from the network as there may occasions, for example during the summer period where the pressure in the network is already too high.
- Difficulties in publishing current pressures in distribution online due to the topology of the networks

Figure 28 Rules for determining the quantities of biomethane to be covered by the incentive schemes

Indicative hydrogen injection projects

Snam Rete Gas, launched in early 2019 an experiment of introducing a 5% hydrogen and natural gas blend into the Italian gas transmission network. The experiment a first of its kind in Europe, was conducted in the town of Contursi Terme, some 100 km to the south of Naples. It involved the supply of a blend of hydrogen and natural gas from a pressurised tank to two industrial companies in the area: a pasta factory and a mineral water bottling company.



A second similar experiment is planned within 2020. This second experiment will aim for an increased percentage of hydrogen.

Summary: Enabling factors and barriers for the injection of new gases in gas distribution

Table 17 Enabling factors and barriers for the injection of new gases in distribution for Italy

Enabling Factors	Barriers
+ In its Energy and Climate Action Plan of 2018, Italy has specified a goal of 8% in the penetration of advanced biofuels, including biomethane. + The Biomethane Decree of 2018 and Italy's commitments towards further penetration of advanced biomethane by 2030 have resulted to positive market dynamics. + Rules for new connections of biomethane plants are incorporated in the network code of the transmission system operator. + Information on new biomethane connections is made available by Snam on a monthly basis. Snam also includes a devoted location in its website providing information on new connections.	– There is no framework for the promotion of other types of new gases (except biomethane) – Rules for biomethane connections to distribution are not in place – There are no rules for the connection of new gases other than biomethane. – All existing information is available in national language.

Netherlands

Overview

Biogas from fermentation has been produced in the Netherlands for several decades. Currently (2019) about 250 installations are producing biogas at over 100 locations across the country. Biogas is typically burned in CHP facilities and boilers for the production of electricity and heat (830 GWh of each in 2018)[123]. Quantities of biogas upgraded to biomethane outpaced biogas for electricity in 2018 reaching 940 GWh. Although values remain low (just 0.2% of total gas consumption), the government has presented an ambitious plan for a tenfold increase of green gas injected to the networks by 2030.

Green gas production is supported by SDE +/++ scheme which targets five categories of green gas production, differentiated according to raw materials, scale and technique. These are: small-scale mono-manure fermentation, large-scale mono-manure fermentation, sludge digestion, all-purpose digestion and biomass gasification. The scheme also supports electricity production from biogas. Favourable taxation for green gas is also in place.

A blending obligation for green gas exists in the mobility sector and the government has plans for increasing the obligatory share of CO_2. Barriers recently recognised by the government include the lack of adequate and suitable location for the installation of new-gas facility and lack of transport routes for biomass and also lack of support. Recently (March 2020), the government announced that a possible solution to the bottleneck shall be the reuse of mining sites and existing, currently not utilised, direct lines to gas production fields. A study is underway.

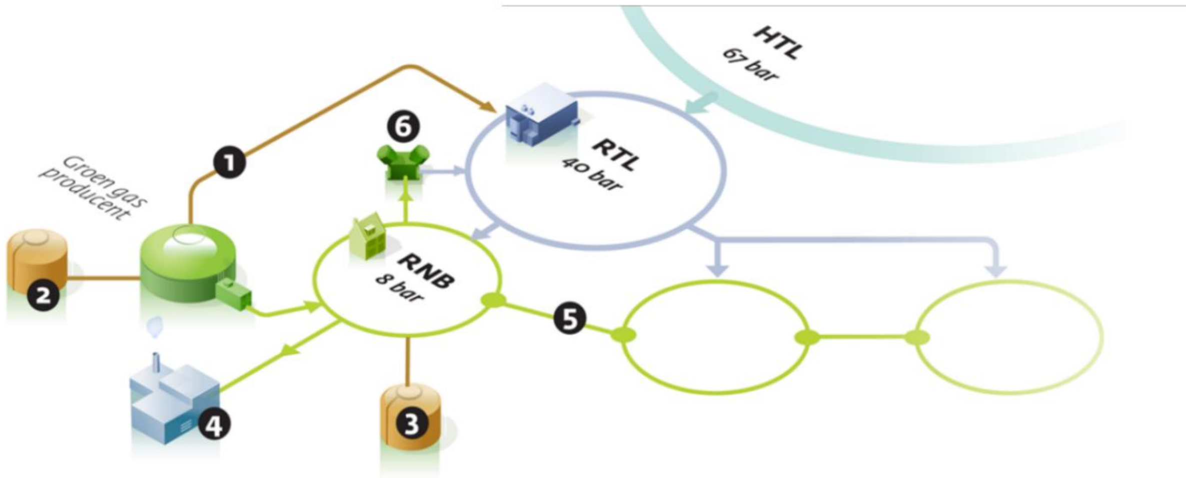


Figure 29 Alternative solutions considered by Dutch network operators to accommodate the imbalance between continuous biogas supply and demand; (1)direct connection of producers to transmission; (2) buffering or storage at the producer' s site; (3) storage at middle pressure network; (4) meet the demand of continuous customers (institutions, power, industry); (5) additional connections at distribution level and loops; (5) compression to transmission.

National Framework

In the Netherlands, injection of biomethane and hydrogen is allowed in the distribution grids as well as in the transmission grid, if the gas complies with the quality standards that are stated in the Ministerial Decree on gas quality. In practice, this means that biogas needs to be upgraded to biomethane in order to comply with the gas quality standards. The maximum hydrogen content that is allowed according to the Ministerial

[123] Kamerbrief Routekaart Groen Gas, March 2020, https://www.rijksoverheid.nl/documenten/kamerstukken/2020/03/30/kamerbrief-routekaart-groen-gas

Decree on gas quality is a molar fraction up to 0.02% in the transmission grid and 0.5% in the distribution grid.[124]

Network operators recognise that one of the issues of potential green gas producers is the available input space in the Dutch gas network[125]. An study conducted in collaboration by the TSO GASUNIE and the Regional System Operators has calculated that the injection of 105 PJ green gas (circa 29,000 GWh, 0.8% of the annual gas consumption) will require approximately 300 million euros in grid investments. The study[126] considers a range of alternative investments as shown in **Figure** 29. To facilitate these investments, the report makes a number of recommendations, such as drawing up a technical assessment framework for the various solutions by the network operators. It is reported that a plan on how to address grid reinforcements is under consideration by the regulator.

Regulatory Framework for the injection of new gases into networks

Terms and conditions regarding connection of new gas facilities to the distribution network and new gas injection are included in a supplementary document of the Distribution Network Code. Table 18 provides a summary. Besides topics related to quality, all other rules related to the interaction between the producer and the network operator (rules related to connection and operation) are the same as with conventional gas.

The network code includes definitions of renewable and low carbon gases such as landfill gas, synthetic gas, bio synthetic gas, green gas and biogas.

There is also a distinction between a production unit defined as an installation in which fermentation of organic material takes place and a reprocessing unit. The latter is defined as an installation in which raw gas from the production unit is upgraded to natural gas quality.

The producer may contract with one or more suppliers.

We have not managed to identify connection rules regarding new-gas facilities and connection charges.

Table 18 Summary of rules for the connection of biomethane plants to natural gas transmission and distribution networks in the Netherlands.

Topic	Responsible entity	Tasks Assigned
General provisions on Quality and Safety		
Safety and technical efficiency of the network	System Operator	
Odourisation	Producer	The code specifies that the production unit shall be equipped with all equipment to measure gas quality and odorise the gas for injection to the network

[124] Regeling gaskwaliteit - https://wetten.overheid.nl/BWBR0035367/2016-04-01#Bijlage8
[125] https://www.gasunietransportservices.nl/aangeslotenen/systeembeheerders/groen-gas-invoeder-worden
[126] https://www.netbeheernederland.nl/_upload/Files/Adviesrapport_'Creeren_voldoende_invoedruimte_voor_-groen_gas'_122.pdf

Topic	Responsible entity	Tasks Assigned
Compliance with quality specifications, pressure and ability for odourisation according standards	Producer .	The code states that the DSO may define the frequency of sample collection. The producer is responsible for checking gas quality both continuously and non-continuously.
Quality and pressure Specifications	System Operator	The maximum hydrogen content that is allowed according to the Ministerial is a molar fraction up to 0.02% in transmission and 0.5% in the distribution. The producing installation is also equipped with pressure control equipment so that the gas is injected according to the requirements of the DSO. Pressure is also checked at the DSO side of the flange
	Labelling	
Guarantees of Origin	Producer /Supplier /Delegated Entity for GOs	Issuance of guarantees of origin is compulsory. New-gas producers register with

Indicative hydrogen injection projects

The port of Eemshaven shall host NorthH2 project, a joint venture between Shell Netherlands, TSO Gasunie and the port of Groningen. Feasibility work on what would be the largest green hydrogen project in the world started in February 2020. The plan would see 3 to 4 gigawatts of offshore wind capacity established in the North Sea by 2030 purely for the manufacture of green hydrogen. Electrolysers will be based in Eemshaven, along the northern coast of the Netherlands, and potentially offshore as well. The project could be expanded to 10 gigawatts of offshore wind by 2040 dedicated to green hydrogen production.

A second project using natural gas to produce hydrogen is underway in the port of Rotterdam.

Hydrogen Strategy

The Netherlands is, after Germany, the largest producer of so-called gray hydrogen in Europe. About 10% of Dutch natural gas is used for the production of hydrogen, with significant CO_2 emissions as carbon capture storage (CCS) technologies are not in use. Not only is there substantial experience in relation to hydrogen handling in terms of safety and security but also a comparatively large industrial market that can provide the necessary demand as basis for the transition to sustainable hydrogen.

On 30 March 2020, the Minister for Economy and Climate published a vision and action plan for hydrogen to 2050. Three phases are identified for hydrogen deployment. The first (current) phase involves the development of green hydrogen installations within industrial clusters where there is already demand for hydrogen. In a next stage it is likely for the development of a more extended network. In the long term, seasonal storage may be required, potentially large-scale storage in salt caverns or empty gas fields. The policy agenda is drawn along 4 pillars as analysed below:

- **Laws and regulations for the deployment of the existing gas network.**

  The hydrogen chain is likely to develop towards a network sector just as is the case with electricity and natural gas with features of a national monopoly. The government recognises that there is a public role for the development of the hydrogen network - certainly in the start and development phase as the introduction of a new carrier is a complex process that will take decades to complete. Besides hydrogen-only network, use of hydrogen blends in the existing gas network are envisaged. Conditions for the transport of hydrogen are under investigation by the transmission operators (Gasunie and also the electricity operator TenneT). Gasunie and TenneT have already demonstrated the need for development of the electricity grid and the hydrogen grid in proper coordination and also in coordination with the State for the location of electrolysers.

  In the letter, the government declares a commitment to examine the specific role of network operators in the hydrogen chain. Network operators have also been assigned the task to initiate hydrogen pilot projects in collaboration with market parties, with the aim to investigate a workable.

  A guarantees of origin system is also in place.

- **Cost reduction and upscaling of green hydrogen**

  A commitment to achieved cost reductions through a large upscaling of green hydrogen production is announced. Such an upscale will be achieved by support to research and development activities and through a so called temporary aid of 35 mil € per annum. A subsidy of € 1 064 per tonne of avoided CO_2 is foreseen plus an additional subsidy of € 300 per ton. An evaluation mechanism on the effectiveness of these measures is also foreseen.

  A study on the coupling of offshore wind production with hydrogen is underway and foreseen to be concluded in S1 2020. The study is expected to also quantify avoided costs due to congestion rents in electricity networks.

  In the letter, the possibility to increase the demand for green hydrogen (physical or via certificates) by introducing a compulsory blending obligation remains open to be addressed in a future policy. The government acknowledges the benefits of mandatory mixing to create demand.

- **Sustainable final consumption**

  Reference is made to specific policies in the context of the implementation of the Renewable Energy Directive (Directive 2018/2001/EU) and to actions regarding (a) the ports of Rotterdam and Amsterdam and specific industrial zones (b) transport with solid commitments for 300,000 fuel cell vehicles in 2030 (c) buildings with a national hydrogen programme to investigate the use of hydrogen for heating (d) electricity sector with initiatives under way to investigate the decentralised electricity production and hydrogen storage. Again, here reference is made towards the avoidance of congestion in the electricity grids. (e) agro-sector. It is acknowledged that the agro sector offers opportunities for both the generation and use of hydrogen. Farms have many options for the decentralized generation of renewable electricity (wind and solar PV on stables and commercial buildings). In addition, the use of CO 2 -free hydrogen for agricultural machines, tractors and heavy agro-logistics offer several opportunities for sustainability.

- **International and regional cooperation and research and development**

  Focus is placed at cooperation at European level and regional across member states but also at national level given the experience on natural gas production at the northern parts of the country.

Summary: Enabling factors and barriers for the injection of new gases in gas distribution

Table 19 Enabling factors and barriers for the injection of new gases in distribution for the Netherlands

Enabling Factors	Gaps
+ Clear definitions, distinction between a production and a conversion plant. Several types of gases are allowed for injection. + Strong government commitment to the promotion of new-gases including hydrogen.	▪ The websites of DSOs refer to the fact that they support the injection of new gases, nevertheless no information is provided to interested parties. All existing information is available in national language.

Conclusions from national assessments

All countries reviewed in this Section have adopted specific provisions regarding the connection and operation of new gas plants. As anticipated, in countries with support schemes and targets for new gas penetration by a specific deadline, the process is accelerated. The example of France here is the most relevant.

In most cases, provisions are specific to biomethane and thereby the connection of other types of gases is excluded. Lack of specific rules for the connection and operation of new-gas plants are a clear barrier to entry. The case of Italy where the distribution system operators have not yet incorporated ARERA's request for new-gas rules is an example of zero connections at distribution level due to lack of framework. On the contrary, at transmission level where the framework is in place, connections to biomethane plants are realised.

Costs for new connections are in some cases borne by the producers (e.g. Italy) and in other cases shared between producers and network operators (e.g. France, Germany). A techno-economic analysis before deciding on a new connection is carried out by some operators (e.g. France). The French Regulator CRE has established a detailed methodology for the assessment of new connection requests and the allocation of costs between producers and system operators.

Second comer rules are present in some cases (e.g. Italy for transmission only and Germany). In Italy, the NRA set that if in a period of the first 10 years, one or more parties connect on the same pipeline originally constructed to accommodate the first connectee, the network operator shall return a portion of the instalments already paid to the first connectee. In Germany the approach is similar. If additional connections are added within ten years after the first grid connection, the network operator must distribute the costs as they would have been paid if all interested parties connected at the same time and reimburse original connectee for any additional amount paid.

We have not been able to identify a methodology for the calculation of available capacity at distribution neither confirmed the existence of potential congestions at distribution level. Such information may be a result of dedicated national studies. Realisation of connections, and thus capacity allocation, at the countries reviewed is on a first-come-first served basis. Connection refusals need to be justified in some cases but rules and conditions upon which a connection may be refused maybe unclear. Connection times are not always specified.

During operation, DSOs have the right to refuse injection of new-gases into the network on grounds of quality, odourisation and lack of capacity. However the methodology and criteria upon which injection due to lack of capacity is not allowed, are unclear. We have not been able to identify clear obligations upon DSOs for the maximisation of linepack utilisation and optimisation in network operation. In some countries (e.g. Germany) priority rules for the injection of biomethane in comparison to natural gas injection are in place.

In some of the Member States reviewed (e.g. Austria, Germany), new gas plants are excluded from the typical balancing obligations applicable to all other suppliers. For example in Germany, biogas balancing group contracts have a twelve month balancing obligation (accounting period) with a ± 25% flexibility provided. This flexibility refers to the cumulative deviation of the amount fed into the network to the amount withdrawn within the accounting period. Compensation is only due when the balancing limits are exceeded.

The sites of the operators in most cases do not include information on how to connect a new-gas plant, connection costs, times and clear rules. Connection and operation rules are in some cases scattered in a number of documents and decisions of the national Regulator and challenging to retrieve. Transparency obligations upon DSOs are limited. Critical parameters such as quality and pressure are not published. The lack of transparency templates as developed for transmission, LNG and storage systems is noted. Typically information is available at national languages.

System operators are actively involved in technical assessments regarding hydrogen injection. This includes indicatively Snam Rete Gas in Italy and GrDF in France. In the Netherlands, the TSO Gasunie together with DSOs are focussing on a design of alternative distribution-level storage solutions to account for the seasonality of gas consumption amidst continuous new-gas production. We have not identified cases where a DSO is directly involved in a new-gas production facility in the sense of owning such a facility and/or the gas produced. Such an investigation – DSO-by-DSO- was not in the scope of the present study.

Assessment of the European Legal Framework on Natural Gas Regarding Gaps and Barriers to the Penetration of New Gases

Overview

This Chapter provides a review of the EU Legal Framework with a specific aim to identify gaps and barriers towards the penetration of new gases into distribution networks as well as gaps in the tasks currently assigned to DSOs that may restrict its evolving role in the context of energy transitions. The review focuses mainly on the provisions of Directive 2009/73/EC and Regulation (EU) 715/2009. Detailed comments are provided in Appendixes 2 and 3. We have also reviewed Regulations (EU) 312/2014, 703/2015, 459/2017, 460/2017 on balancing, interoperability and data exchange, capacity allocation and tariffs and provide comments where relevant. The **N**ew **E**lectricity **D**irective and the **N**ew **E**lectricity **R**egulation (Directive (EU) 2019/944, hereinafter NED and Regulation (EU) 2009/943 hereinafter NER) are also considered as provisions for the development of electricity storage systems and the new role of the DSOs in the electricity sector may be also relevant to gas. We note however, that gas and electricity are different energy products. A level playing field argument does not necessarily justify the principles and framework of the electricity sector to be transposed to the natural gas sector.

Definition of new gas

It is well recognised that decarbonising the EU's gas sector requires identifying and deploying the best sources of alternative gas e.g. see EU Long Term Strategy. However, the wide variety of feedstocks and conversion pathways for producing gases necessitates more nuanced terms than "renewable" or "sustainable" to characterize their suitability for long-term decarbonisation. Further, a "new gas" which is the terminology adopted in this study may well be neither renewable nor sustainable. We have already underlined elements on the new gas definition debate in Chapter 2.

The framework provided by the Directive 2009/73/EC (Gas Directive) concerns mainly the gas market as it has developed so far, with natural gas being the main form of gas flowing into the gas system and being the main commodity of the gas market. While the Directive refers to the gas market it does not include a definition for the term "natural gas" and it does not define the term "other types of gases" appearing in Article 1(2) of the Directive. It is generally acknowledged that the term natural gas refers to conventional natural gas of certain composition and combustion characteristics as defined by each Member State. Further, the Gas Directive applies to biogas or other types of gas in so far as such gases can technically and safely be injected, and transported through, the natural gas system[127]. These provisions of the Gas Directive in principle allow for any other type of gas to be injected in the system including new gases as discussed in Chapter 2.

[127] Art. 1(2) of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

Topic	Assessment	
Definition of New Gases		▪ The Directive does not foreclose the injection of new gases of any type in so far as such gases can technically and safely be injected. Implementation of this provision in Member States is subject to further scrutiny.

legend

The topic addressed is absent in the gas legal framework however its absence may not be necessarily a gap or barrier to the penetration of new gases in European networks

The topic addressed is absent in the gas legal framework and its absence is considered a a gap or barrier to the penetration of new gases in European networks

However, interviewees in this study acknowledged that in many countries, legislation refers to biogas as a fuel for electricity generation, but only limited provisions exist for the injection of biomethane or other types of new gases including gases produced from P2X facilities into transmission or distribution networks. The review in Chapter 0 has also highlighted that in some countries, existing framework provides only for the injection of biomethane and excludes other gases.

Facilitating the use of new gases through appropriate definitions in the Gas Directive may be considered in a future potential proposal for an amendment of the Gas Directive.

We also note that although the Gas Directive in its current form allows in principle for the injection of any type of gas provided that meets the technical and safety requirements of the system, such requirements may not be fully defined or not defined in such a way to accommodate new gases. Currently studies on the determination of acceptable blending ratios are under way[128]. Absence of standards can be detrimental to the development of new-gas production while too rigid standards can also hinder the development of new gases.

Definition for new-gas production facilities and new-gas producers

While 'production' is referred in the Directive 2009/73/EC, the activity itself is not framed in detail, for instance with clear definitions of the activity itself or reference to production facilities. A definition of new gas facilities may be considered in a future amendment of the Gas Directive.

We also note that power-to-gas or even biomethane plants or other plants producing gas of lower carbon footprint than conventional gas maybe also considered as energy conversion rather than energy production facilities. For power-to-gas, their role as converting plants is self-explanatory. A conversion role may be also assigned to biomethane plants in the sense that they upgrade and purify biogas of low calorific value to biomethane. Plants that through the processes of pyrolysis or steam reforming *convert* conventional natural gas or other fossil fuels to synthetic gases of lower carbon footprint may be also considered as energy conversion facilities. Interviewees to this study also noted that there might be a scope to define biomethane plants or power to gas plants with emphasis on the fact that they are energy conversion rather than production facilities.

[128] E.g. Marcogaz infographic at the 33rd Madrid

Topic		Assessment
Definition of New Gas Facilities and New Gas Producers	(green/red)	▪ Directive 2009/73/EC in its current form does not provide a definition for production facilities and producers. ▪ As production is not in the scope of the Directive a definition may not be necessary - subject to the analysis regarding the involvement of DSOs in new gas facilities.
Regulation of new gas facilities	(red)	▪ Currently there are no provisions for the regulation of new gas facilities in the Directive.

The regulatory implications for a distinction between "production" and "conversion" may be significant depending on the provisions to be included in the framework. Production is not within the scope and context of Directive 2009/73/EC (with the exception of the unbundling requirement upon network operators not being allowed to own production facilities).

On the other hand, a "conversion facility" depending on its size can be subject to third party access (TPA) requirements. A small facility can be closed to third party access, while a larger facility can also operate as a 'tolling station' open to third party access and providing conversion services.

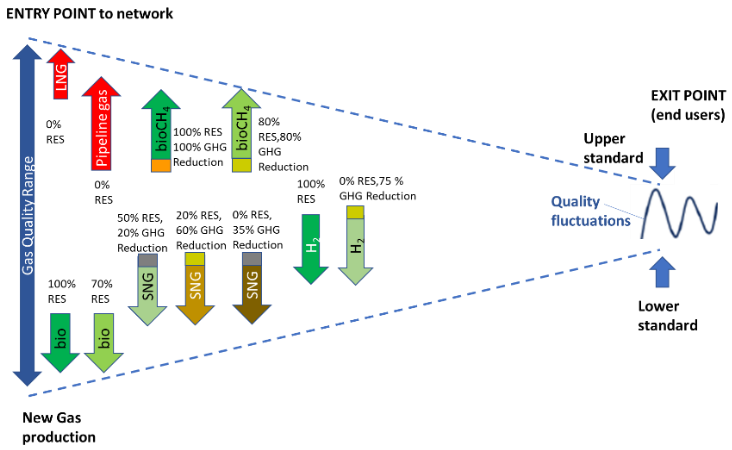


Figure 30 Gas quality range for the various types of new gases, conventional pipeline gas and LNG. Here quality range refers to the calorific value or the Wobbe index[129]. Percentages of renewable gas and GHG reduction shown in the figure are arbitrary and are included by way of an example.

Gas disclosure obligations

Figure 30 shows qualitatively that new gases may vary both in their renewable content and also in terms of their GHG footprint. In this new era of mixtures of conventional gas with new gases, the end consumer will be receiving a gas of variable carbon content. In our view it is necessary for the end consumer to receive information from the supplier on the type of gas mixture delivered as is the case with electricity. Note that as early as with Directive 2003/54/EC, an obligation was introduced upon suppliers to inform their customers on the mix of fuels used to generate the electricity supplied. The fuel mix disclosure obligation has long been linked to the overall functioning of liberalised electricity markets where customers are able to choose not only their energy supplier, but also a particular energy product. As a result, they have the possibility to choose between different offers in terms of price, company profile, sources of energy and technologies used for electricity production. A fuel mix disclosure provision enables customers to make an informed choice about the energy they buy. The CEER in its Advice on customer information on sources of electricity[130] stresses that a complete picture of how electricity offers, and in particular "green electricity" offers, are managed and marketed should be provided to consumers. Clearly, this line of arguments is directly expandable to gas.

Topic		Assessment
Mix disclosure obligation	●	▪ The Directive does not foresee an obligation for suppliers to disclose the carbon and/or renewable content of their fuel mix

Access of new-gas producers and suppliers to the wholesale market

Suppliers active at distribution level have been traditionally considered as retailers. They deliver gas to end consumers. During energy transition and latter at steady state, they may also transform to aggregate buyers of new gas and sellers at the wholesale market.

New-gas producers connected at distribution level with bilateral contracts with end-consumers are also retail suppliers. New-gas producers should be also able to access the wholesale market to sell their production, Figure 31.

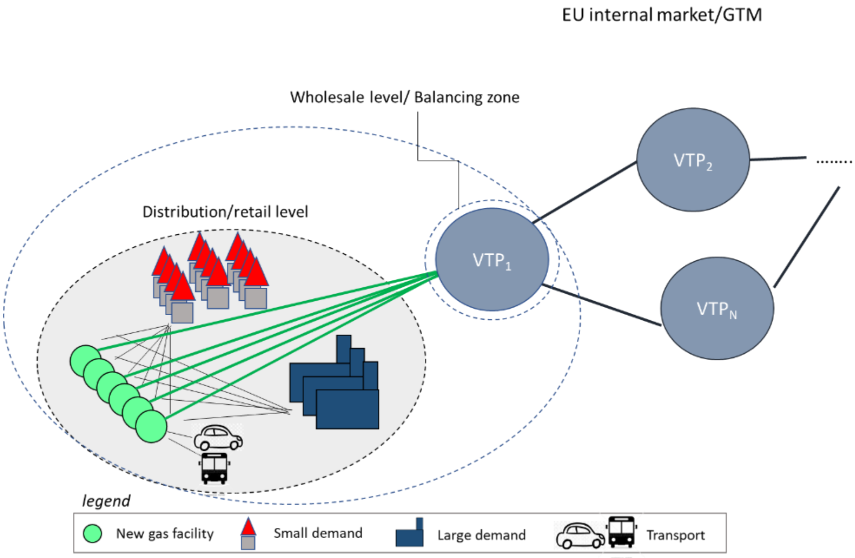


Figure 31 Conceptual view of market operation in the presence of new gas facilities.

Directive 2009/73/EC does not hinder access of retailers to the wholesale market. On the contrary, the European framework through Regulation (EU) 312/2014[131] provides for the definition of balancing zones to also include distribution networks. Nevertheless, a study commissioned by ACER a few years ago[132] shows that smaller participants to wholesale gas markets may face barriers in accessing trading hubs. Barriers may be

[130] CEER Advice on customer information on sources of electricity, Ref: C14-CEM-70-08, https://www.ceer.eu/documents/104400/-/-/8207e038-1312-a790-c1c1-8b2fd7ac58c9
[131] Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks.
[132] Barriers to gas wholesale trading Final Report submitted by Kantor S.A. to ACER
, https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/Kantor_report_on%20barriers%20to%20gas%20wholesale%20trading.pdf

related to too complicated or too demanding requirements and obligations to access the wholesale gas market, high costs of subscribing (una-tantum fees, subscription fees) and operational costs (volume fees) at trading platforms (balancing platforms, VTP, OTC brokers, exchanges), heavy requirements/costs for a wholesale trading license to trade at the VTP. We have not assessed further this topic as it is beyond the scope of the present work. We note however that access of retailers (and thus also new-gas producers) to national VTPs should be facilitated by the regulatory framework at EU level as the anonymous and structured form of the VTP operation and the assumption of risk by the clearing party can substantially lower entry barriers and hence is an essential prerequisite for fertilising retail competition.

For clarity it is noted that the VTP is expected to retain its role as a market place for gas regardless of type or source (conventional, new-gas, gas of reduced footprint, hydrogen). The type of gas and its contribution to global warming should be certified by guarantees of origin traded at a dedicated market place.

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Topic	Assessment	
Access to VTP		▪ The EU legal framework and the GTM promote VTP access. Nevertheless, there are still several Member States with illiquid or non-functioning hubs. Access to VTPs for small new-gas suppliers may be have inherent challenges.
Customer switching		▪ The Directive imposes upon Member States several obligations towards facilitating customer switching. Still the CEER in a series of reports continuous to recognise barriers in the supplier switching process

Customer switching

Article 3(6) of the Gas Directive sets that Member States shall ensure that: (a) where a customer, while respecting the contractual conditions, wishes to change supplier, the change is affected by the operator(s) concerned within three weeks; and (b) customers are entitled to receive all relevant consumption data. Despite the legal provisions, CEER continues to identify barriers to supplier switching.

Besides the regular difficulties related to switching, the new-gas producer is a new entrant. The new entrant faces higher barriers and it is more difficult to convince the final consumer to purchase its new product which may also happen to be more expensive than the conventional equivalent. The amount of new gas produced (too low) may also be a barrier per-se. Examples of current biomethane facilities indicate very small sizes and, in some cases, also non-continuous production. Non-continuous production may also be an issue with P2G facilities particularly if their operation depends on what would otherwise be curtailed electricity production or the price of electricity versus the price of the renewable gas.

The customer structure in distribution networks needs also to be considered. In distribution, typically there are comparatively few (in terms of numbers) but large (in terms of consumption) consumers: district heating plants, hospitals, schools, some industrial and commercial enterprises, public administration. Then the remaining bulk comprises many small residential and commercial consumers.

Note that gas is a primary source of energy. The switching process does not necessarily relate solely to supplier switching butalso switching from and to other energy sources. Interviewees have suggested that switching to different sources of heat, including to/from district heating should also be considered, monitored and where required facilitated if barriers exist.

Registration, licensing and technical requirements

Based on information provided by the Interviewees, in many countries there is legislation with reference to biogas, as a fuel for electricity but limited provisions for biomethane or other types of new gases for injection into transmission or distribution. The same issue would apply also to power to gas (P2G) facilities, especially when it comes to a large-scale deployment of such facilities.

Furthermore, as noted in ACER's recommendation[133], a system of mutual recognition for wholesale market authorisations/licences (or an equivalent mechanism) should be introduced across the EU. Once a wholesale supplier/trader is authorised or licensed in one Member State, based on well-defined standardised minimum requirements, including in relation to the reliability and financial solvency of the entity, this should automatically be recognised in any other Member State that requires a licence or authorisation for wholesale trading.

Lack of technical rules and also specific safety standards in a Member State can be a barrier to entry (barrier to connection of new facilities) as already discussed in Section 0.

Topic	Assessment	
Wholesale and retail licensing	🔴	▪ A system of mutual recognition for wholesale market authorisations/licences (or an equivalent mechanism) still does not exist at EU level. ▪ There is no mutual recognition for retail licenses
Licensing of new gas facilities	🔴	▪ Article 4 of the directive refers only to natural gas facilities with no provisions for biogas or other types of gas. Interviewees informed that in many countries there is legislation with reference to biogas, as a fuel for electricity but limited provisions for biomethane or other types of new gases for injection into transmission or distribution.
Safety standards for hydrogen and Blending limits	🔴	▪ Undefined standards for hydrogen including blending limits. Lack of a roadmap for reaching an agreement on blending limits at least on national level.

Unbundling and involvement of DSOs in new-gas facilities

Directive 2009/73/EC calls for legal and functional unbundling of gas distribution operators with over 100,000 customers. Operators with less than 100,000 customers may still act as producers and/or suppliers of gas. Due to the lack of a definition on what is a new-gas plant, as already discussed in Section 0, it may be interpreted that certainly DSOs with less than 100,000 customers can own a new-gas production facility. Terms and conditions for access of third parties to such facilities are also not specified in the EU legal framework.

Topic	Assessment	
Lack of clarity in the ownership of DSOs of new gas plants	🔴	▪ DSOs with less than 100,000 customers can own a production facility without any unbundling obligations ▪ As there is no definition of a new-gas plant in the Directive, the legal framework is unclear. This includes also access conditions in case the production facility provides a conversion service to more than one users

Unbundling provisions for gas DSOs are the same as for electricity (of former Directive 2009/72/EC). The NED reincorporated the same provisions with no further adjustments or additions which indicates that a need for more stringent unbundling rules was not identified at least in the electricity sector.

[133] "The Bridge Beyond 2025 Conclusions Paper, see footnote 52

For the analysis in this Section it is useful to also note that the potential involvement of electricity DSOs in energy storage facilities (for example batteries) has been the focus of a strong debate and has been explicitly addressed in the NED. Article 36 provides that electricity DSOs should not own, develop, manage or operate energy storage facilities. Only by way of derogation, Member States may allow the involvement of electricity DSOs in energy storage facilities upon NRA approval, or where certain conditions are fulfilled such as lack of market interest for the development of these facilities by the market and strictly for ensuring the secure and reliable operation of the system. Even in this case (lack of market interest), the NED provides that the NRAs shall perform, at regular intervals or at least every five years, a public consultation on the existing energy storage facilities in order to assess the potential availability and interest in investing in such facilities. Where the public consultation, as assessed by the regulatory authority, indicates that third parties are able to own, develop, operate or manage such facilities in a cost-effective manner, the regulatory authority shall ensure that the distribution system operators' activities in this regard are phased out within 18 months.

In gas, currently, a number of DSOs and also TSOs are involved in consortia that develop new-gas plants, inject new gases to networks and evaluate implications on network components and combustion devices of end consumers. Current involvement of DSOs is at R&D or demonstration level. We have not been able to verify whether system operators own, in part or in full, new-gas facilities. From our review, it appears that operators are solely focused on the part of the R&D or demonstration project which relates to the technical assessment of new gas injection in networks (including impact of hydrogen).

As already discussed in Section 4.2, stakeholders through two public consultations carried out in 2019, by CEER[134] and ACER[135] expressed diverging opinions regarding ownership of new-gas production facilities by system operators. One group of respondents, mainly commercial market actors, were of the view that TSOs/DSOs should not be involved in activities open to competition. Another group, mainly network operators, were of the view that TSOs/DSOs should be allowed to invest in power-to-gas and biomethane plants to support scaling up of the market. Stakeholders consulted in the present work also expressed diverging opinions. As a general trend, they agreed that at no time should DSOs/TSOs trade or sell an energy product. One stakeholder pointed out that distribution operators could own a production facility and should be reimbursed through network tariffs in case they are obliged by the regulator to build such a facility (for example in case there is a clear customer need and the market cannot deliver at a reasonable cost or in a timely manner).

Overall, it is our view that it is preferable for activities related to new-gas production to be developed under market conditions by interested parties completely distinct from regulated monopolies taking however into account the fact that smaller gas DSOs may also be gas suppliers. The involvement of DSOs can then be as follows:

- The supply arm of DSOs with less than 100,000 customers (“small DSO”) may be involved in new-gas production, as already inferred by the Gas Directive. Further clarity may be needed in a potential future revision of the Gas Directive to better reflect involvement of the DSOs in new-gas facilities (including their definition as noted in Section 0).
- For DSOs with more than 100,000 customers, an exemption could be foreseen under special market conditions e.g. market kick-start (in analogy to the NED framework for electricity storage, but not for serving similar purposes).

[134] See footnote 57
[135] Public Consultation on the Gas Bridge beyond 2025, from 23 July to 9 September 2019

For the sake of clarity we note that the ownership and operation of new-gas production facilities by system operators may be developed under two models, Figure 32. One is that of a vertically integrated undertaking owning and operating the new-gas facility and the produced gas, (Figure 32a). This for example can be the case of a small DSO with less than 100,000 customers and subject to accounting unbundling of the production activity from the remaining activities of the DSO. Another model could be that of a fully unbundled system operator, who owns and operates the facility (Figure 32b). In the second model the DSO may offer a "conversion service" to independent third parties. Such service maybe the conversion of biogas to biomethane or electricity to gas (P2gas plants). In the latter business model, third party access rules shall be required and subject to approval by the regulator. Each supplier would need to pay a (conversion service) tariff for the use of the infrastructure.

Note that national frameworks as reviewed in Section 0 do not yet foresee the model of Figure 32(b). However in interviews carried out in the context of this study, we have confirmed that the model of Figure 32(b) is plausible for reasons related to economies of scale, subject to further technical and financial assessments. We discuss this topic further in Section 0.

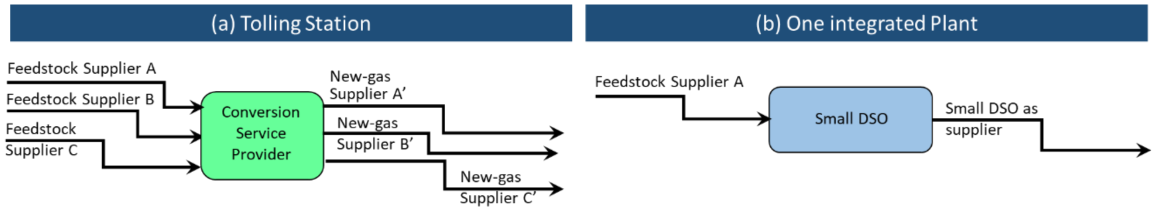

Figure 32 Alternative business models for a new gas facility; (a) the new gas conversion facility operates as a comparatively large scale conversion facility and is used by a number of suppliers both in the upstream and in the downstream; (b) alternatively each interested party (or consortium, including a small DSO) builds its own facility

Interviewees also raised the topic of size of the new-production facility indicating that potentially all DSOs maybe involved in very small production facilities regardless of the business model (e.g. Figure 32(a)) and facilities below a critical size may be exempted from regulation. Note that the topic of the "size of an infrastructure" has also been addressed by ACER[136]. ACER notes that as regards the development of new technologies and activities for gas, barriers for genuine, first-of-a-kind or small-scale pilots, should be avoided.

The size of a certain infrastructure has also been addressed previously in the Gas Directive (re. Article 36). Rules and conditions applicable to major infrastructures as in Article 36 however are substantially different than in the case of a small-scale new-gas production plant.

Gas DSOs role in relation to new-gases

The Directive includes no provisions related to the obligation of the DSO to connect new gas facilities. Further the right of the DSO to refuse a connection is only based on the general statement of Article 35 "Natural gas undertakings may refuse access to the system on the basis of lack of capacity or where the access to the system would prevent

[136] Recommendation No 02/2019 of the European Union Agency for the Cooperation of Energy Regulators of 19 November 2019 on the regulatory response to the future challenges emerging from developments in the internal gas market
https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2019.pdf

them from carrying out the public service obligations". There are also no provisions for the promotion of renewable sources or TSO and DSO cooperation.

Looking into precedence from the electricity sector, the NED (Article 31) provides that Member States may require the distribution system operator, when dispatching generating installations, to give priority to generating installations using renewable sources or using high-efficiency cogeneration. Interviewees in this study have also stressed that gas DSOs should provide for injection priority to new-gas facilities and that a role towards the promotion of RES should be assigned to gas DSOs. In the country review of Chapter 0 we have identified that in a number of countries injection priority is already assigned to new-gas producers.

The NED also calls for the distribution system operator to act as a neutral market facilitator and cooperate with the TSO. Interviewees in this study noted that in current gas regulations, day-to-day operation and network planning is upon gas TSOs even though European Network Codes (particularly those related to day-to-day operation[137]) are relevant also for the DSOs. They commented on the lack of a structured form of cooperation between DSOs and their upstream TSOs or ENTSOG. However, they confirmed that cooperation exists on an informal level but that the level of cooperation, and coordination may vary across Member States. Interviewees particularly stressed the need to strengthen the interlinkage between DSOs and TSOs on network planning in both gas and electricity. We note that a need for more structured cooperation between TSOs and DSOs was also been acknowledged in the conclusions of the 2019 Energy Infrastructure Forum.

Finally Article 31(10) of the NED also foresees that Member States or their designated competent authorities may allow distribution system operators to perform activities other than those provided for in this Directive and in Regulation (EU) 2019/943, where such activities are necessary for the distribution system operators to fulfil their obligations provided that the regulatory authority has assessed the necessity of such a derogation. Thus the NED allows for a more dynamic form of regulation, while this flexibility is currently absent in the Gas Directive.

Topic	Assessment	
Role of the DSOs in relation to connecting new gas facilities	🔴	▪ The Directive includes no provisions related to the obligation of the DSO to connect new gas facilities.
Role of the regarding the promotion of RES	🔴	▪ The Directive does not include specific provisions
Cooperation between TSOs and DSOs	🔴	▪ No specific form is specified. No formal obligations for cooperation
Flexibility upon DSOs to carry out other services subject to NRA approval	🔴	▪ No such provisions exist in the Gas Directive

Smart metering

The NED includes (Articles 19-21) extensive provisions on smart metering, their functionalities and the entitlement of customers to a smart meter even in case of a negative CBA at a Member State level. These additional requirements in the case of electricity reflect the developments in the sector over the past few years in terms of technology

[137] Such as the Network Code on Interoperability and Data Exchange (Regulation (EU) 2015/703) and Balancing (Regulation (EU) 312/2014)

(e.g. smart homes, distributed generation, electric vehicles) and the market products (e.g. demand response). For gas, obligations on smart metering are lighter in comparison to electricity provisions (NED and also Directive 2009/73/EC) and reflect the different conditions and needs of the gas system.

Interviewees in this study, when asked on the relation, if any, between smart meters and new gases stressed again the fundamental difference between electricity and gas based on the traveling time of the latter from production to consumption in comparison to the former. It was stressed that real time measurements do not make sense for gas because what is actually metered is one cubic meter (1 m^3). However 1 m^3 of one gas, at the same pressure and temperature, may have a very different energy content in comparison to another gas. Thus at this stage one may conclude that new-gases do not call for more detailed provisions in the context of gas smart meters. Note however, as discussed in Section 0 that some form of smart metering may be due to assist on the calculation of linepack probably towards the end of the energy transition phase.

Smart measuring of gas quality

We have already touched on the topic of quality of new gases in Chapter 2 and Section 0. In this Section we analyse the importance of metering and monitoring of gas quality in networks taking into account that at least in the energy transition period, consumers shall be receiving a blend of different gases with potentially substantially different properties.

Figure 33 presents a simple example of two end-customers (End-customer A and End-customer B) connected to a distribution network. Customer A consumes all hydrogen produced by the P2Gas facility and an equal amount of conventional gas from transmission. Customer B receives only gas from transmission. For each 1m^3 metered by the conventional meter of Customer A, the amount of energy delivered is 34% less than the amount of energy delivered to Customer B[138].

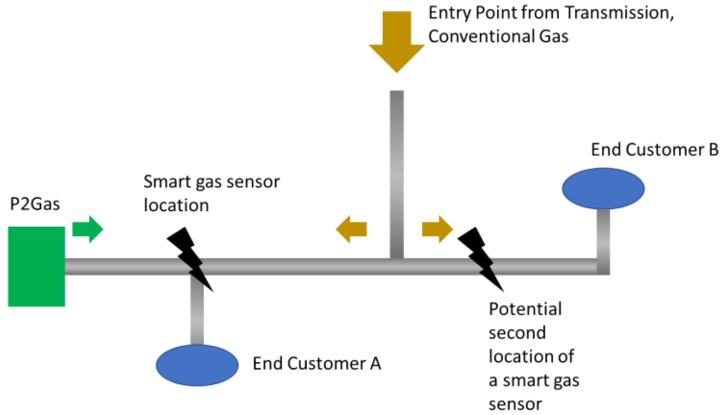

Figure 33 Simple example on different types of gases received by customers depending on their location at the distribution network.

Interviewees noted that development of gas smart grids and gas-quality smart meters shall be driven by the need to know the energy content of gas inside the grid. A smart gas grid is related to sensors that are affordable and capable of measuring the calorific value of gas in the grid. In our simple example above at least one such sensor would be required at the branch to End-Customer A. Depending on the consumption patterns of Customer A and the production levels of the P2Gas a second sensor may also be

[138] Calculation based on an assumed calorific value for conventional natural gas of 11 kWh/Nm3 and a calorific value of hydrogen of 3.45kWh/Nm^3,

necessary towards Customer B. The number of sensors that may be required on an actual case depends on the grid topology, the location of the P2Gas facilities and the amount of hydrogen produced. Current gas-chromatographer technology would need to progress further into cost-efficient, versatile sensors. Simulation software forecasting gas quality shall be also necessary.

The EU framework neither assigns an explicit role on DSOs for gas quality metering and monitoring nor does it address the need for the development of smart and affordable quality meters and their installation in networks.

Topic	Assessment	
Role on DSOs regarding gas quality measurements	●	▪ The EU framework neither assigns an explicit role on DSOs for gas quality metering and monitoring nor does it address the need for the development of smart and affordable quality meters and their installation in networks.

Network operation, flexibility and storage at distribution level

Article 2(15) of Directive 2009/73/EC defines linepack as “the storage of gas by compression in gas transmission and distribution systems, but not including facilities reserved for transmission system operators carrying out their functions”. In simple terms, linepack is the ability of any gas grid to store gas. Every transmission or distribution pipe has a maximum pressure, under which it may be operated. This pressure depends on the material, diameter and thickness of the pipe. Typical maximum pressures in DSO pipes are 100 millibar (mbar), 1 bar, 4 bar or 16 bar. Operation pressure is typically lower than the maximum pressure and can vary during the day depending on the supply and demand balance

Topic	Assessment	
Storage and Linepack	●	▪ The scope of the Directive on linepack provisions touches also upon distribution. ▪ IT is subject to interpretation whether existing provisions on storage are applicable to distribution.

Usage and availability of linepack in a transmission system may differ from country to country. To a large extent, usage depends on the balancing system adopted and whether linepack is adequate to be offered as a commercial service. For distribution, currently there seems to be no commercial use of linepack. From the interviews carried out in the context of this project, we understand that some DSOs have considerable flexibility and regularly use their linepack to plan their services. However, approaches vary between Member States and often rules are absent and third party access to linepack at distribution level is typically not provided. It is also understood that in the absence of smart meters located at end-consumption points DSOs are only able to obtain approximate values of linepack on a daily basis.

There are a few specificities related to pressure levels within distribution networks (and thus to the availability of linepack). For example, typically, demand is low during the summer months and pressures in the network may be also low. As a P2Gas facility is expected to be receiving curtailed electricity for the production of gas throughout the year, there may be a potential for some of the produced gas to be stored within the system linepack or in a storage facility at distribution level during summer months. The same could be the case with biomethane. Depending on the design of the balancing system and the technical capacity of the network there may be both a scope and an opportunity for the DSO to offer a commercial linepack flexibility service accompanied by a potential tariff for the service. A storage service may be also provided in a separate storage facility. Dutch DSOs as discussed in Section 0 already consider distribution storage or network looping to increase network storage(please refer to Figure 29).

Further, we note that Article 33 of the Gas Directive, although not explicitly stated, it refers to a storage facility connected to the transmission system. However, storage facilities may also start to emerge at distribution level to accommodate imbalances between continuous supply for new gases and low demand. The regulation of such storage facilities and relevant tariffs to be paid by users would need to be specified. The Directive, even for the case of transmission, recognises a competition element on storages therefore allowing for complete foreclosure to TPA and negotiated access.

Network planning at DSO level, coordination between TSOs/DSOs regarding network planning and cross-sectoral coordination

Directive 2009/73/EC does not assign to gas DSOs an obligation for network planning. Interviewees noted that in some countries, electricity and less often gas DSOs already develop and submit to the regulator their development plants. Approaches vary across DSOs and from one Member State to another.

Connections of new-gas facilities to distribution networks will be inherently related to some network expansions at mid and possibly low pressure. Installation of gas quality measuring equipment at least at some distribution network branches will gradually become necessary and further upgrades may be needed to accommodate potentially variable new-gas injection patterns taking also into account the strong seasonality of demand in distribution.
Ultimately, high penetration levels of new gases at distribution level may call for the installation of compressors to support reverse flows from distribution. Overall, such actions indicate a need for forward planning and further coordination between gas TSOs and DSOs.

Topic	Barrier identification and assessment	
DSO and TSO cooperation and network planning		▪ The Directive does not impose an obligation upon DSOs for the creation of network development plans. ▪ There are no provisions for a structured TSO/DSO cooperation during network development planning.

In electricity, the NED introduced provisions (Article 32(3) to (5)) obliging an electricity DSO to publish, at least every two years and submit to the regulatory authority a network development plan. The NED specifies that the plan should provide transparency on the medium and long-term flexibility services needed, and set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan of electricity DSOs shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator may consider as an alternative to system expansion.

According to the NED, Member States may decide not to apply the development plan obligation to integrated electricity undertakings which serve less than 100 000 connected customers or small isolated systems. In our view, even the smallest DSO should be obliged to submit to the NRA estimates on the evolution of demand and injection of new gases into their network. Indeed, in some Member States transmission codes or other regulatory documents impose upon DSOs the obligation to submit their expectations for the evolution of demand at their networks to the TSO, however once again there is no common practice.

Interviewees pointed out that currently an informal process is in place with the TSO consulting with the DSOs on future investments at their common interconnection points and that accordingly the TSOs inform ENTSOG on the expected demand at its own network but confirmed the absence of a standardised process. The common European

TYNDP, now carried out jointly by ENTSOE and ENTSOG, calls for further alignment at national levels between the electricity and gas TSOs and in turn between electricity TSOs and DSOs, gas TSOs and DSOs and also for cross-sectoral coordination to address the infrastructure requirements towards the transition from a centralised to a decentralised energy system. Stakeholders pointed out that this transition to a decentralised system is already present in electricity as RES production on distribution has been taking place for quite some time but it is also now also becoming a reality with biomethane and P2X plants gradually developing in areas where there are curtailments.

Further DSO/TSO coordination

Directive 2009/73/EC has no provisions for cooperation between electricity and gas system operators. Interviewees noted that a cooperation between TSOs and DSOs exists both for operational reasons and also in terms of network planning but this is more on an informal basis.

The CEER in its Position Paper on the Future DSO and TSO Relationship[139] has already noted that obligations for cooperation should be defined on European level while more detailed regulation should be left upon Member States. The CEER also noted that:

- The type and nature of DSOs (e.g. size, DSO-connected or TSO connected) should be considered when designing the instruments and requirements to deliver the wider objectives, in order to avoid disproportional or negative cost/benefit impacts and
- For the future DSO-TSO relationship it is necessary to enhance a whole system approach at every level of responsibility i.e. NRAs, TSOs and DSOs. This includes cooperation in the efficient use of (and where appropriate, trialling of) innovative solutions and approaches for system operation and network planning.

Further cooperation at EU level between ENTSOG and an EU level DSO entity is also not foreseen, see Section 0.

Gathering systems

Gathering systems, i.e. a number of biogas producing plants connected to a gathering pipeline that transports biogas to a biomethane plant, have been brought up during the interviews although some interviewees questioned the potential of development of such systems in Europe unless it is comparatively large companies. A gathering system has strong resemblances to the concept of upstream pipelines. Subject to further consultation, Article 34 of the Gas Directive provides adequate legal support for the realisation of such systems.

We note however that the business model depicted in Figure 32(a) can accommodate one or more upstream gathering systems.

The role of the NRAs towards new-gases and DSOs

Directive 2009/73/EC does not include specific provisions in relation to DSOs and decarbonisation or renewable energy commitments.

On the contrary, NED introduces a few modifications to the role of NRAs regarding the electricity sector. Here we take note only of those that are of relevance to the penetration of energy storage.

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[139] CEER Ref: C16-DS-26-04 Position Paper on the Future DSO and TSO Relationship, https://www.ceer.eu/documents/104400/-/-/e8532c60-56d5-17bf-cecb-b4f9594fe0c4

Article 59(1(l, m, o and z)) introduced specific obligations regarding the role of the NRAs as follows which are also relevant to the role of the NRAs in relation to new gases and may be considered in a future amendment of the Gas Directive.

Topic	Assessment	
Drivers to innovation and incentives	🔴	▪ Directive 2009/73/EC includes only a minor reference to the need for innovation
Role of NRAs regarding new-gases	🔴	▪ Directive 2009/73/EC does not include specific provisions for the role of NRAs regarding monitoring of new-gas production and DSO monitoring in relation to new gases.

Drivers to innovation and incentives

In Directive 2009/73/EC there is only a minor reference to the need for innovation. This is justifiable as the Directive was agreed at a time when emphasis was on the completion of the internal gas market rather than on innovative approaches. Innovation in Directive 2009/73/EC is only referred to in the context of innovative price formulas mainly to accommodate energy efficiency improvements (Article 3(8)). The recent amendment (Directive (EU) 2019/962) of the Gas Directive, also makes no reference to innovation. Currently however such a need is emerging strongly both in the electricity and also in the gas sectors if the EU is to meet its Long-Term Strategy to 2050.

Innovation relates both to the development of new-gas technology at a commercial level and to new services to be offered by the DSOs (for example flexibility, coordination with the electricity sector, smart sensors for quality measurements).

Regarding new-gas production technologies, interviewees noted that technology specific approaches should be avoided and stressed that a technology neutral approach is a least-cost approach with tenders published and answered by interested market parties in a competitive way.

Regarding DSOs, interviewees noted that regulation should allow DSOs to innovate. Regulatory schemes that include a maximum ceiling of costs for DSOs do not provide proper drivers for DSOs to invest. For DSOs to be able to adapt to energy transition they need to be able to invest and take up new technology. Incentive regulation for gas DSOs supporting research and innovation projects should be promoted at EU level and gradually incorporated in the legal framework of Member States.

Interviewees clarified that they support the definition, at European level, of high-level guidelines regarding distribution tariffs but do not advice for a major EU regulatory overhaul. High-level common principles included in the EU NC TAR, ensuring that network tariffs are non-discriminatory, reflect network costs associated with the use of the system, promote innovation and are capacity based where possible to follow costs in a fairer way may need to be defined in European level. It was also suggested that regulators consider the trade-off between CAPEX and OPEX at national level when incentivising innovation.

Interviewees further commented on the need for overall support to the use of new gas which could be promoted by a review of emission targets to reflect, for example for cars well-to-wheels emissions rather than tank-to wheels emissions and also provide incentives and tax breaks for the purchase of natural gas vehicles. They also noted that regulation can have a key role to play in supporting renewable gases through policy decisions supporting the increased production of decarbonised gas and specific economic measures including tax incentives investment grants for pilot projects introduction of trade certificates for the production and trade of such gases that would allow market players to reduce their CO2 emission footprint. It was pointed out that one of the main barriers to renewable gas is that the attractiveness of power generation in comparison to grid injection so that the latter is very limited. It was strongly pointed out that policymakers should show the same ambition for renewable gases that they have for renewable electricity and that the natural gas infrastructure and the potential for renewable gases varies between Member States, so a range of approaches should be supported.

The NED places some focus on innovation, in the recitals of the Directive it is stated:

- By taking advantage of new technology, **new and innovative energy service companies** should enable all consumers to fully participate in the energy transition (Recital 5).
- The Union would most effectively meet its renewable energy targets through the creation of a market framework **that rewards flexibility and innovation**. A well-functioning electricity market design is the key factor enabling the uptake of renewable energy. (Recital 9)
- Healthy competition in retail markets is essential to ensuring the market-driven deployment of **innovative new services** (Recital 10).
- Member States should maintain wide discretion to impose public service obligations on electricity undertakings in pursuing objectives of general economic interest [...]. Nevertheless, public service obligations in the form of price setting for supply [...]constitute a fundamentally distortive measure that often leads to the accumulation of tariff deficits, the limitation of consumer choice, poorer incentives [...] and the restriction of competition, **as well as to there being fewer innovative products and services on the market** (Recital 22).

Within the main body of the Directive reference to innovation is made in Article 19 in relation to smart grids.

Regulation (EU) 2019/943 also provides for innovation. It defines a demonstration project as a project which demonstrates "a technology as a first of its kind in the Union and **represents a significant innovation** that goes well beyond the state of the art" (Art 2(24)) and makes ensures that innovation is taken into account the tariff methodologies by stating that tariffs "shall reflect the fixed costs of [..] distribution system operators and **shall provide appropriate incentives** [..] over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, **and to facilitate innovation** in interest of consumers in areas such as digitalisation, flexibility services and interconnection" (Art 18(2)).

In a potential future revision of the Gas Directive further provisions fostering innovation may be considered. These are further discussed in Chapter 7 under Recommendation 12.

Participation of DSOs at EU institutional level

Gas DSOs are not formally represented at an EU institutional level e.g. by an EU DSO entity as it is the case with transmission system operators, represented by ENTSOG.

The NER introduced the new EU DSO Entity as an umbrella organisation for the cooperation of electricity DSOs at Union level, in order "to promote the completion and functioning of the internal market for electricity, and to promote optimal management and a coordinated operation of distribution and transmission systems". (NER Article 52(1)).

Interviewees in this project expressed strong support to the creation of a similar entity for gas. It was mentioned that the gas EU DSO Entity will be "one of the main building blocks for coordinated planning and cooperation between TSO and DSO". Diverging opinions were collected as to whether the scope of the EU DSO entity specified in the NER should be expanded to include gas DSOs or whether a new separate entity should be formed by analogy to ENTSOs (one for electricity and one for gas). One interviewee noted that if a separate entity is created then their provisions for a formal coordination between electricity and gas should also be included in addition to any provisions for coordination of the DSO entity with ENTSOG. Another stressed that one of the tasks of the gas DSO entity should at least on coordination between gas DSOs regarding gas quality and hydrogen blending by analogy to the American Society Petroleum Engineers which sets the minimum standards and serves as a platform for exchange of now how. Our recommendations on the role and specific tasks of the EU DSO entity are provided in Chapter 7 under Recommendation 14.

Closed distribution systems and hydrogen networks

Article 28 of the Gas Directive refers to closed distribution systems. The NED includes a similar article where it sets that Member States may provide for national regulatory authorities to exempt the operator of a closed distribution system from:

(a) procuring energy to cover energy requirements;
(b) having tariffs, or the methodologies underlying their calculation, approved by the NRAs
(c) procuring flexibility services and to develop the operator's system on the basis of network development plans;
(d) not being allowed to own, develop, manage or operate recharging points for electric vehicles; and
(e) not being allowed to own, develop, manage or operate energy storage facilities.

Closed systems in gas can well refer to private hydrogen networks that have traditionally serviced the petrochemical industry. Interviewees expressed the opinion that these networks for as long as they continue their current line of business they should remain as currently are exempted from regulation.

ACER, in the Agency's recommendation of November 2019, states that consideration should be given to a regulatory framework for a pure hydrogen network since uncertainty over future regulation could hamper (and delay) the initial investments in decarbonised gases. Some basic principles or recommendations (e.g. on issues such as third-party access) could be potentially consulted at EU level before investments are made. ACER stressed that as it is important to ensure effective regulation of networks and equally it will be important to avoid unnecessary regulation of competitive activities. For example, where hydrogen is piped to a single industrial user the need for rigid regulatory requirements is unlikely. On the other hand, should hydrogen networks become widespread, and where blending of decarbonised gas increases in existing networks, there may be value in leveraging the liquidity of existing markets and the understanding of existing rules and regulations. During energy transition, the flexibility provided by Article 28 for closed systems should be maintained.

Data management and interoperability requirements and procedures for access to data

Implementation of smart metering in gas is more confined than in electricity. Only few EU Member States (France, Italy, Netherlands) have proceeded with implementation at distribution. On the other hand, digitalisation, data management and topics related to cybersecurity are expected to gain further importance in the future.

The NED introduces specific provisions for data management (Articles 23 and 24). Interviewees have expressed support these provisions are also adopted for gas DSOs in a future amendment of the Gas Directive. They also noted that topics related to data management and cybersecurity are equally relevant to gas DSOs and that there is scope for cooperation with electricity DSOs on these areas both at national level and at the level of the EU DSOs.

Sector Coupling

Currently the Directive 2009/73/EC offers no provisions for sector coupling between electricity, gas and also heat (district heating).

Interviewees agreed that there is inherent relation between electricity and gas and this relation will be further enhanced in the future with the emergence of power to gas facilities.

Enforcement

Directive 2009/73/EC already includes enforcement provisions and empowers regulators to impose penalties upon market Interviewees suggested that a review of the Commission's enforcement powers to ensure that the Commission is able to address instances of consistent lack of progress in implementing EU rules more effectively and quickly.

A review of ACER powers to monitor and assess the level of competition, and actively support the implementation of the EU Long Term vision was also recommended. ACER has currently limited ability to go beyond the reporting of formal compliance and to play a role in implementation processes.

Review of Commission Regulation (EU) 715/2009

Regulation (EU) 715/2009 targets mainly transmission systems. It also includes provisions for LNG terminals and storage facilities. The Regulation sets non-discriminatory rules for access conditions to infrastructure taking into account the special characteristics of national and regional markets with a view to achieve harmonisation of rules at least at interconnection points. The regulation also provides for the establishment of ENTSOG, its tasks, for cooperation between TSOs and TSOs and ENTSOG and also for the establishment of network codes.

Here we address main elements of Regulation (EU) 715/2009 with a view to assess whether there is scope for their expansion to distribution.

Main concepts addressed in Regulation (EU) 715/2009 such as tariffs, capacity allocation, balancing are further specified in the respective European network codes (Regulations (EU) 2017/460, 2017/459, 312/2014). We also address these topics in the respective Sections below. We note however that European network codes seek, to large extent, to achieve harmonisation in the European gas market as defined in the Gas Target Model (GTM[140]) i.e. a competitive European gas market, comprising entry-exit zones with liquid virtual trading points and where market integration is served by appropriate levels of infrastructure which enables gas to move freely between market areas to the locations where it is most highly valued. The infrastructure referred to in the GTM is in essence at transmission level. Unless new gas production at distribution becomes a significant source of gas in Europe and physical reverse flows from distribution to transmission need to be enabled, it is unlikely that a degree of harmonisation as required by the network codes would be also needed for distribution. In this context we look into the main principles of European Network codes but we have not conducted a by-article review as we consider that scope for their expansion to distribution cannot be yet justified. This opinion is shared by interviewees that participated in this study.

[140] ACER, European Gas Target Model Review and Update, January 2015, https://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/Documents/European%20Gas%20Target%20Model%20Review%20and%20Update.pdf

Table 20 Distribution tariff design principles proposed in a 2015 study[141]

System Sustainability	Economic Efficiency Principles	Protection Principles
Sufficiency – network tariffs should allow the full recovery of efficient network costs and a reasonable return on capital	**Productive efficiency** – network services should be delivered to consumers at the lowest possible cost	**Transparency** – the methodology and results of tariff allocations should be published and available to network participants, whose bills should clearly state each charged component
Achievability and adequacy of the regulated rate of return – the regulated rate of return should guarantee a return in line with the relative risk of the investments and financing conditions.	**Infrastructure cost efficiency:** tariff regulation should aim to incentivise efficient investment	**Non-discrimination** – all users that belong to a certain category and demand the same network services should be charged the same, irrespective of the end use of electricity
Achievability of the incentive components – the incentive mechanism should pose achievable targets.	**Operational cost efficiency**: tariffs regulation should aim to reduce operational (including administrative) costs;	**Equity** – certain categories of users, like low income users, or users that are located in remote areas, are charged a tariff which is lower than the cost of the services received Simplicity the methodology and results of the tariff allocations should be easy to understand and implement
Additivity of components – various tariff components must add up to give the total revenue requirement to be recovered	**Coordination** – tariff regulation should aim to minimise the total system cost by coordinating distribution investment and operation with other stakeholder's investment decisions and operation including transmission, generation, consumption, ancillary services.	**Predictability** – tariffs should be based on observable variables, known by users and other interested parties, who should be able to easily forecast future charges
	Allocative efficiency – tariff should incentivise the users to use the grid efficiently	
	Peak reduction - Network tariffs should promote peak demand management and	**Stability** – tariffs methodology should be stable in order to minimize regulatory uncertainty

[141] see footnote 142.

System Sustainability	Economic Efficiency Principles	Protection Principles
	aim to reduce infrastructure cost for peak demand	
	Flexibility - Tariffs should encourage system flexibility, e.g. distributed generation, demand response and energy efficiency	**Consistency** – tariff regulation has to comply with the legislation in place.
	Market promotion - Tariffs should promote well-functioning electricity and gas markets	
	Cost reflectiveness – consumers should be charged in accordance with the costs of the services they have received considering their contribution to peak demand and their position in the network.	
	Promotion of innovation – tariff regulation should not create any barrier to DSO innovation	

Tariffs in the context of Commission Regulation (EU) 715/2009 and Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas

Regulation (EU) 715/2009 defines general concepts for tariff design such as obligations for an Entry/Exit system, transparency in the tariff methodologies taking into account the need for system integrity, cost reflectivity, return on investments and non-discrimination between system users. These concepts are brought forward mainly with a view to secure market liquidity and avoid distortions in cross border trades. Provisions in the Regulation add to Article 41(8) of Directive 2009/73/EC which requires NRAs to ensure that transmission and distribution system operators are granted appropriate incentives, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities. References to a linkage between transmission and distribution tariffs and energy efficiency actions are also provided in Directive 2012/27/EU (Articles 15 and Annex XI, see Appendix 2).

To our knowledge there is no recent study on gas distribution tariffs across EU Member States that assesses the application of general tariff design concepts as those highlighted by the Regulation by Member States.

A 2015 Consultancy Study funded by the European Commission [142], presented a number of principles for a best practice tariff design in distribution systems (both electricity and

[142] Study on tariff design for distribution systems, Final Report, https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF

gas). These principles, broken down in 3 categories are summarised in Table 15. The study does not include a full assessment across Member States regarding the level of implementation of the proposed principles, it is clear however that insufficient and inefficient implementation of main tariff design principles as highlighted by Regulation (EU) 715/2009 and further specified in Table 15 can be a barrier to the operation and development of distribution systems and also a barrier for the connection of new gas facilities at distribution networks. We include a high-level assessment against the principles of Table 15 in the country analysis of Section 0.

In 2017, the CEER published a Guideline of Good Practice on Electricity Distribution Tariffs based the 7 principles, Figure 34. The CEER further specifies these principles for their implementation to distribution electricity tariffs in the context of energy transition. There may be a scope at least for the development of a relevant document for gas distribution.

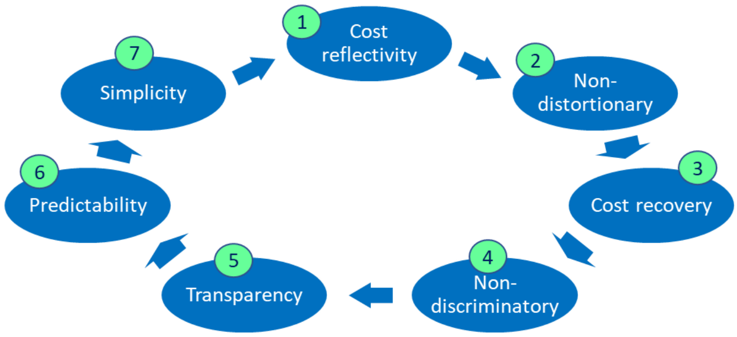

Figure 34 Principles for the design of distribution network tariffs according to the CEER Guideline of Good Practice on Electricity Distribution Tariffs[143]

Connections of new gas facilities are essentially new infrastructure added upon the existing distribution systems. Our country review in the next Section shows that there is no consistent approach across countries. In some cases, the costs are borne entirely by connected system users. In other cases, costs are shared between DSOs and connecting parties. By analogy to the provisions of Regulation (EU) 347/2013(Article 11, par. 7) which calls for national regulatory authorities to cooperate in the framework of ACER, establish and make publicly available a set of indicators and corresponding reference values for the comparison of unit investment costs for projects of common interest, there may be a scope for the development of a similar document containing unit investment costs for new connections.

Note that following the public consultation on the new uses of gas[144], CEER concluded that it is important to distinguish between use-of network tariffs (UoNT) and other charges or taxes and stresses that the use-of-network tariffs are meant to pay the cost of using the networks and clarified that network tariffs should not be used to subsidize technologies.

The principles of Regulation (EU) 715/2009 are further implemented by Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas (EU NC TAR). As stated in the introduction to this analysis (Section 0 above) it is our view that the current level of penetration of new gases does not support an extension of the European network codes to distribution. However, EU NC TAR sets further

[143] https://www.ceer.eu/documents/104400/-/-/1bdc6307-7f9a-c6de-6950-f19873959413
[144] CEER, Stakeholder Comments on CEER's Public Consultation on Regulatory Challenges for a Sustainable Gas Sector Ref C18-RGS-03-03 https://www.ceer.eu/documents/104400/-/-/031e2bd0-7801-ff04-bc7c-c20135fffc5e

specific useful principles that could be taken into account should the Commission consider issuing a recommendation to Member States regarding tariff methodologies for distribution systems.

In recital (2) of EU NC TAR and also in Chapter VIII, it is well recognised that in order to reach the objectives of market integration, enhancing security of supply and promoting the interconnection between gas networks transparency of tariff structures and procedures towards setting them should be increased. EU NC TAR recognises that it is necessary to set out the requirements for publishing information related to the determination of the revenues of transmission system operators and to the derivation of different transmission and non-transmission tariffs and that network users should be able to understand the costs underlying transmission tariffs and to forecast transmission tariffs to a reasonable extent. Although we are not advocating for an extrapolation of EU NCTAR to distribution a further degree of transparency should be pursued with DSOs and NRAs.

Third Party Access and capacity allocation in the context of Commission Regulation (EU) 715/2009 and Commission Regulation (EU) 2017/459

Regulation (EU) 715/2009 introduces general concepts for third party access to transmission infrastructure (and also LNG and storage). It sets upon system operators the obligation to offer firm and interruptible capacity products on a long- and short-term basis under equivalent and non-discriminatory conditions based on standardised contracts. Guarantees demonstrating creditworthiness of signatories should be non-discriminatory, transparent and proportionate. Clearly these general principles are also relevant to distribution. The Regulation also calls for compatibility between contracts offered for storage and LNG facilities and transmission contracts. Compatibility between distribution and transmission contracts maybe also relevant.

Regulation (EU) 715/2009 also notes a need for standardisation of capacity products and contract durations to facilitate market integration. This requirement is further implemented in Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems (EU NC CAM).

Regarding standardised connection rules and capacity allocation, the country review of Section 6 shows that a distribution network code and access rules are in place in all countries considered. Rules for the connection of new gas facilities at distribution level also exist in most countries considered in this study (this is with the exception of Italy where however the Regulator has issued a relevant decision not yet implemented in the distribution network code). Further research is required to establish whether standardised connection and capacity reservation contracts for new gas facilities are in place as well as a methodology for the calculation of relevant guarantees. It is clear that lack of standardised contracts and of a transparent methodology for establishing and guarantees can be a significant barrier to entry. Our review shows that firm capacity contracts are offed at least on an annual basis to new gas facilities and that capacity allocation is typically on a first come first served basis. However, it is generally not clear how the requirement of Article 35 of Directive 2009/73/EC on refusal of access[145] is implemented as there seems to be no specific methodology for the estimation of the technical capacity of distribution networks. The topic of technical capacity maximisation is also discussed in the next Section and is relevant to capacity allocation, congestion management, daily operation and network planning. Regulation (EU) 715/2009 specifically calls for the maximisation of technical capacity and sets an obligation upon TSOs to make available

[145] "Natural gas undertakings may refuse access to the system on the basis of lack of capacity or where the access to the system would prevent them from carrying out the public service obligations", Article 35(1) of Directive 2009/73/EC.

to market participants the maximum capacity at all entry and exit points taking into account system integrity and efficient network operation. In the introduction to this study we have noted that gas networks can serve well as means to reduce the need for expansions in the electricity network through appropriate mechanisms ensuring efficient coupling between the electricity and gas sectors so that a transparent methodology for the calculation of technical or the available capacity at distribution level is essential. Some harmonisation in the calculation methodology may be necessary so as to ensure a level playing field across distribution systems.

EU NC CAM defines standardised capacity products (yearly, quarterly, daily, intraday), imposes the allocation of capacity via auctions at interconnection points based on an EU wide calendar and prescribes a standardised process for the assessment of demand at interconnection points based on a two-step process and an economic test. The regulation already excludes national entry/exit points and interconnection points to third countries from most of the provisions of its provisions (unless the national regulatory authority decides otherwise). EU NC CAM also calls for coordination in the implementation of standard communication procedures, coordinated information systems and compatible electronic on-line communications, such as shared data exchange formats and protocols amongst TSOs and also once again for maximisation of capacity. We do not see a scope for the extrapolation of EU NC CAM to national points and subsequently to distribution.

Congestion management

Regulation (EU) 715/2009 introduces main principles for congestion management once again based on transparency, non-discrimination and compatibility across Member States and specific rules to address contractual congestion. National distribution network codes typically do not include congestion management rules at distribution level. This is also confirmed from our review under Section 0.

Balancing rules in the context of Commission Regulation (EU) 715/2009 and Commission Regulation (EU) 312/2014

Regulation (EU) 715/2009 calls for transparent, non-discriminatory market based balancing rules and places obligations upon TSOs to provide reliable on-line based information on the balancing status of network users so that they can take timely corrective actions. The Regulation also sets that imbalance charges shall be cost-reflective to the extent possible, cross subsidisations should be avoided and the regulatory framework should provide appropriate incentives on network users to balance their input and off-take of gas. Calculation methodologies for imbalance charges and final tariffs shall be made public by the competent authorities or the transmission system operator, as appropriate.

Variant 1	Variant 2
Information on non-daily metered and daily metered off-takes is based on apportionment of measured flows during the gas day;	Information on non-daily metered off-takes is a day ahead forecast

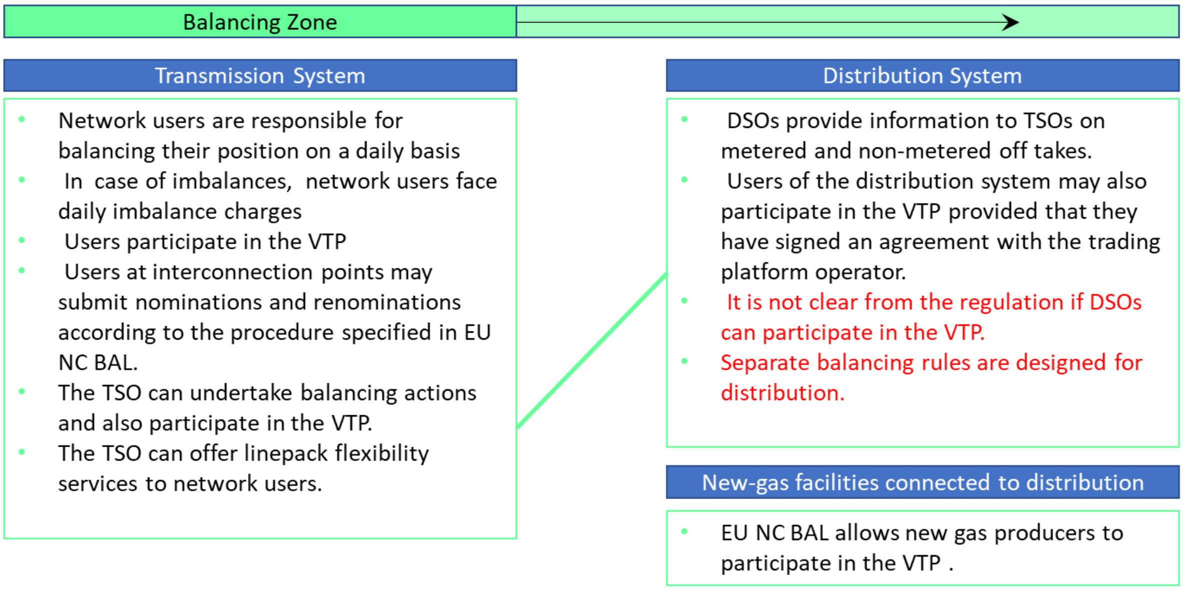

Figure 35 Schematic representation of main provisions of EU NC BAL in case that a balancing zone does not include distribution. Although currently balancing zones in many Member States encompass only transmission systems, EU NC BAL allows for its extension to distribution.

The provisions of Regulation (EU) 715/2009 are further specified in the European balancing network code (Regulation (EU) 312/2014, hereinafter 'EU NC BAL'). EU NC BAL applies to balancing zones i.e. to entry-exit systems which may also include distribution systems. Thus, EU NC BAL sets a base for the integration of transmission and distribution at least on operational level.

Furthermore, the Regulation imposes upon DSOs the obligation to provide timely information to TSOs on:

- intraday and daily metered inputs and off-takes on the distribution system regardless whether that system is a part of the balancing zone or not.
- forecasts for non-daily metered off-takes if Variant 2 as shown below is applied.

Figure 35 shows the main elements of EU NC BAL in the case of a balancing zone defined as encompassing transmission only. The figure also includes elements of EU NC BAL related to distribution. According to the Regulation, network users may enter into a legally binding agreement with TSOs irrespective of whether they have contracted transport capacity or not. This agreement shall enable contracting parties to submit trade notifications to the TSO and thus participate in the VTP. Thus, the existing framework already allows for new-gas producers or buyers of their production can participate in the balancing market. A definition for the term Network User is sourced from Regulation 715/2009 where it reads "'*network user means a customer or a potential customer of a transmission system operator, and transmission system operators themselves in so far as it is necessary for them to carry out their functions in relation to transmission*". It is unclear and subject to interpretation as to whether the DSO can participate in the VTP and can also perform balancing actions. However, EU NC BAL allows for new-gas producers to participate in the VTP (as well as the buyers of their production). Figure 35 presents the actual situation in most Member States[146] where the balancing zone is confined to transmission. Integration of transmission and distribution systems in terms

[146] Third ACER Report on the implementation of the Balancing Network Code – 6 August 2018, Second ACER Report on the implementation of the Balancing Network Code – 16 November 2017 (Volume I and Volume II) https://www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Balancing-rules.aspx

of operation and balancing may not necessarily require additional provisions at EU level. However, it will call for a more structure cooperation between transmission and distribution operators on an intraday level, information exchange and also structured cooperation on forecasting.

Our review (Chapter 6) on national frameworks has shown that in some Member States lighter balancing obligations are imposed upon new gas facilities. Such rules may serve well towards promoting new gas facilities.

Transparency

Regulation (EU) 715/2009 introduces a series of transparency requirements. The scope of these transparency obligations is to provide easily accessible and concise information to interest parties so that they can book capacity at entry and exit points. Transparency requirements as described in Annex I(3) of the Regulation have been translated into the so-called transparency templates that may be found at the web sites of all EU TSOs. Transparency templates contain, in summary, the following information:

- Technical capacities at entry and exit points and methodology for their calculation
- A list of the transmission services offered and the standard gas transportation agreement
- Network code
- Gas quality specifications
- Historical data on flows and quality
- Interruption procedures, planned maintenance and
- Capacity allocation, congestion management and secondary market rules
- Rules on balancing and calculation of imbalance charges
- Rules for connection
- Linepack calculation
- Available capacities, reserved capacities and technical capabilities
- Tariff calculation

Similar transparency templates, purposely adapted to reflect the specificities of LNG and storage facilities, have been developed over the past decade and are available in the websites of LSOs and SSOs.

Lack of information on connection and access rules and charges can be a significant barrier to entry for new-gas producers. Our review of Section 0 shows that information is contained in several sources, into national languages and in general is hard to obtain.

Review of Commission Regulation (EU) 703/2015 establishing a network code on interoperability and data exchange rules

The previous Section looked into Regulation 715/2009 and on specific topics such as third-party access, tariffs and balancing as further regulated by Commission Regulations (EU) 2017/459,2017/460, 312/2014. In this Section we look specifically into the provisions of the Interoperability and Data exchange network code (EU NC IA). The Regulation applies to interconnection points except for Article 17 which apply to other points on transmission network where the gas quality is measured and Article 18 which apply to transmission systems in general.

We note that EU NC IA defines a procedure for flow control between adjacent TSOs. Such a procedure is further formalised through an interconnection agreement. An interconnection agreement further includes measurement principles for gas quantities and quality, rules for the matching process, rules for the allocation of gas quantities, communication procedures in case of exceptional events, dispute settlement and amendment procedures.

Article 17 of EU NC IA is also applicable all points on transmission network where gas quality is measured thus also to points between transmission and distribution. The Regulation sets upon the TSO the obligation to inform several parties to receive information on gas quality variation: final customers, network users acting on behalf of a final customer, distribution and storage system operators.

Parties to be informed should typically be those directly connected to the TSO network with operational processes are adversely affected by gas quality changes. The Regulation calls for each TSO to

- define and maintain a list of parties entitled to receive indicative gas quality information;
- cooperate with the parties identified in the above list in order to assess: (i) the relevant information on gas quality parameters to be provided; (ii) the frequency for the information to be provided; (iii) the lead time; (iv) the method of communication.

As already discussed in Section 0, injection of new gases into the distribution network may affect the quality characteristics of the gaseous mixture in the pipelines and that obligations should be imposed upon DSOs to install required measuring equipment and also relevant software that will ensure the required quality of gas in the system.

Further, Article 18, imposes upon ETSOG an obligation to prepare a gas quality outlook based on information provided by TSOs.

Article 19 of the EU NC IA addresses the topic of odourisation and its potential impact on cross border trade. The odourisation of natural gas is an important safety measure to enable the detection of leaks without resorting to sensors or other devices. Odourisation is mostly carried out using sulphur-based odorants. Throughout Europe the requirements for odourisation vary (e.g., specific network level where the gas is odorized, minimum concentration). A discussion towards harmonisation of odourisation is ongoing. EU NC IA provides that where a restriction to cross-border trade due to differences in odourisation practices cannot be avoided by the concerned transmission system operators and is recognised by national authorities, the authorities may require the concerned transmission system operators to reach an agreement within six months, which may include swapping and flow commitments, to solve any restriction recognised. The concerned adjacent transmission system operators shall provide their respective national authorities with the agreement for approval.

Conclusions and High-Level Recommendations

This study encompassed four streams of work:

- **An analysis of the scenarios considered by the PRIMES model** in support to the Commission's Long-term Strategic Vision published in November 2018. Emphasis was placed on projections of new gas consumption in sectors typically encountered at distribution level (residential, tertiary, transport).
- **An analysis on the evolving role of the DSO in the context of energy transition with a view to identify** potential gaps or barriers for the development of new gas facilities.
- **A review of existing rules at distribution level in countries that have achieved considerable progress with the introduction of new gases**. The following countries have been considered: Austria, France, Germany, Italy and the Netherlands.
- **An article by article review of Directive 2009/73/EC and Regulation (EU) 715/2009 and a higher level review of the European network codes (Regulations (EU) 312/2014, 703/2015, 459/2017 and 460/2017).** The relevance of the revised Electricity Directive (Directive (EU) 2019/944) and Regulation (EU) 2019/943) and the results and recommendations included in other studies such as the 'sector coupling study'[147] and existing literature were also taken into account.

The next paragraphs report main findings and recommendations.

Sectoral projections of natural gas and new gases

E3Modelling has provided quantitative modelling (using the PRIMES model) to the in-depth analysis[148] published by the Commission on 28 November 2018 in support to its Long-term Strategic Vision. For the purpose of this study we looked further into our projections for all scenarios considered to support the EU Strategic Vision and analysed findings relevant to distribution networks.

Note that a total of 8 scenarios were examined. A first set of 5 scenarios address the well below 2°C ambition, aiming for GHG emissions reduction levels in 2050 of around 80% compared to 1990 and comprise the following: (1) an Energy Efficiency (EE) scenario achieving energy savings close to the maximum potential, through policies promoting near zero energy buildings and stringent technology standards for appliances, equipment and vehicles; (2) a circular economy scenario (CIRC) with industrial restructuring to optimise resource efficiency and behavioural changes in the transport sector with emphasis on the role of bioenergy (liquids and gaseous); (3) an electrification scenario (4) a hydrogen scenario assuming extended development of hydrogen production and distribution and (5) a Power-to-X scenario leading to the production of synthetic methane and liquid fuels.

Three additional scenarios (COMBO, 1.5 TECH and 1.5LIFE) assume a combination of elements, for both energy demand and supply sectors, from the five abovementioned scenarios. The last two scenarios 1.5 TECH (with more focus on the energy supply sectors) and 1.5LIFE (with more focus on energy demand) were designed to explore the feasibility of the climate neutrality objective and constitute the "1.5°C-GHG" pathways.

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[147] Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU, https://ec.europa.eu/info/sites/info/files/frontier_-_potentials_of_sector_coupling_for_decarbonisation.pdf

[148] https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

Consumption of conventional (fossil) natural gas (excluding non-energy use) is severely reduced by 2050 in all scenarios. The reduction in gas consumption impacts the residential and services sectors serviced by distribution networks. In all scenarios, substitution of natural gas in distribution networks by gases of reduced carbon footprint (biogas, gas from waste, hydrogen and GHG-free gases produced from P2X technologies) is of the order of 10% in 2035. In 2040, gas is substituted by hydrogen by 12% (H2 scenario) and by as much as 50% by GHG free gas and biogas in the remaining (non-hydrogen specific) scenarios. In 2045 and 2050, new gases exceed the amount of fossil natural gas in distribution networks. Total gas demand in 2050 for the residential and transport sector is of the order of 80-130 Mtoe depending on the scenario. New gases amount to 25 to 56 Mtoe. For comparison note that 2015 gas consumption (residential and transport sectors) was of the order of 173 Mtoe (EU-27 and UK). Clearly, subject to additional enabling conditions (e.g. substantial financial support and faster technological maturity than one foreseen in the scenarios of the Long-term Strategic Vision penetration to distribution can occur earlier in time.

New gas penetration in the scenarios examined allow us to distinguish an energy transition period until about 2045 and a steady state with considerable penetration of new gases post 2050.

National implementations

Our review has shown that in countries where penetration of new gases is progressing rapidly, such a penetration is inherently linked to support schemes and new-gas specific regulatory rules for connections and operation. To this end, also national network codes and tariff regulations in those countries have been modified in this direction. However, in a number of countries reviewed, the framework in place allows only for the injection of biomethane and excludes other gases. We also anticipate that in countries where no specific framework is in place, progress in new-gas penetration would be zero or marginal.

We note variations in national implementations in relation to the evaluation of connection charges and rules with some cases costs borne entirely by the connected system users and in other cases shares between the DSO and the connected system users. An obligation for a techno-economic assessment to decide on the costs and benefits of expansions when expansion costs are borne by the DSO exist in some cases. Distribution network planning is in place in all countries reviewed.

Conditions upon which a connection may be refused are not always clear and we have not been able to identity a methodology for the calculation of available capacity at distribution. Capacity allocation is typically on a first-come-first served basis. Connection times are not always specified.

System operators participate in new gas projects. It is not clear if such participation refers to only involvement and support or also to shareholding.

During operation, DSOs have the right to refuse injection of new-gases into the network on grounds of quality, odourisation and lack of capacity. However, the methodology and criteria are not always clear. There is typically no obligation for the DSO to maximise technical capacity offered as is the case for transmission.

In some countries, favourable balancing rules for new gas plants are in place.

A major issue is transparency levels particularly in comparison to transmission. The sites of the DSOs do not include information on how to connect a new-gas plant, connection costs and times and rules. Connection and operation rules are in some cases scattered in a number of documents and decisions of the national Regulator and challenging to retrieve. Transparency obligations upon DSOs are limited so that typically information on critical parameters such as quality and pressure are not published. The lack of transparency templates as developed for transmission, LNG and storage systems is noted. Typically, information is available at national languages.

Review of the EU framework and Recommendations

The key objective of Directive 2009/73/EC and the relevant national regulation was market integration and the development of competition. Harmonisation of rules at interconnection points between transmission networks has been a main focus both of the Directive and also of Regulation (EU) 715/2009 and the European Network Codes.

On the other hand, provisions in the Gas Directive for distribution in the Gas Directive are more high level setting out general principles regarding unbundling (where applicable), third party access, tariffs, role of the DSO and the NRA, transparency and non-discrimination. Implementation has been designed and implemented at national level as a result of cooperation between the national DSOs and the Regulator.

Introduction of production at distribution level, in the context of an internal functioning gas market, inherently implies a gradual integration of transmission and distribution. Taking into account also sector coupling possibilities, an overall general trend towards integration of energy infrastructure (transmission, distribution, electricity, gas) seems to be a plausible case in the not-too distant future.

Recommendations provided below are made with a view of ensuring that the new gas era is designed in a way that preserves the internal market and gradually leads to full integration of transmission and distribution networks. In parallel, a balance between national implementation and EU level regulation should be sought at least in the mid-term.

As ACER has also identified, it is necessary to build on synergies between electricity and gas and seek for political acceptance/support at EU and MS level for a hybrid energy carrier system - utilizing electricity and gas assets efficiently and obtaining improved flexibility and security of supply. Sector integration should be further expanded to also include transport and heat.

Recommendation 1: Type of gas injected into the networks and gas disclosure obligations

- The Commission may consider undertaking a more detailed comparative study on current implementation of Directive 2009/73/EC and relative provisions of gas network codes in Member States (transmission and distribution) to ensure that they do not foreclose the injection of certain types of new gases due to exclusive definitions.
- There may be a scope of extending the Gas Directive and Regulation 715/2009 to apply beyond natural gas specifically include decarbonised gases and hydrogen, with clear carve-outs for direct pipes to individual (or small clusters of) industrial users where additional regulation is unwarranted.
- The introduction and clarification of terms corresponding to "new-gas" and "new-gas production facility" is necessary at European level to ensure consistency between Member States. Lack of consistency may jeopardise the integrity of the internal market.
- Current gas quality standards adopted by Member States are primarily based on mixture composition and a minimum quantity of methane. A study on the gradual transformation of these standards in a softer form like the standards applicable for gasoil, gasoline or lubricants (based more on combustion and fluid mechanical characteristics

rather than composition) should be considered. A European wide study on implications to infrastructure and appliances should also be undertaken.

- The introduction of a mix disclosure obligation upon gas suppliers should be considered in national frameworks so that the amount of renewable gas and their carbon footprint of the gas consumed is gradually made known to consumers. This is also necessary in order to build a climate friendly conscience and raise awareness amongst gas consumers. The Commission may issue a relevant recommendation. Moreover, subject to further assessment, a disclosure obligation should be included in a future amendment of Directive 2009/73/EC.
- Guarantees of origin (GOs) that reflect the contribution of each quantity of gas injected to the grid are also a necessity. Directive 2018/2001 already calls for extending the GO system to also cover renewable gas. In recital (59) of the Directive, it is also suggested that extending the GO system to energy from non-renewable sources should be also an option for Member States as it would provide a consistent means of proving to final customers the origin of gas. The Directive also calls for creation of guarantees of origin for other renewable gas such as hydrogen. Actions towards ensuring a harmonised GO system across Member States should be promoted by AIB that currently is the umbrella for electricity GOs and supported by the Commission. Works on a new gas specific standard (the gas counterpart of CEN - EN 16325) may be initiated.

  Given the large variety of new gases in terms of carbon footprint, there may be a scope, following extensive consultation, to promote an obligatory GO system. Standardisation of gas GOs should be a requirement not only for the purposes of cross-border trade but also to ensure consistency and transparency between Member States regarding the methodology for evaluating GHG savings. The primary nature of a GO, as defined in Directive 2018//2001/EU is to provide proof to final customers that a given share or quantity of energy was produced from renewable sources (or from gas of reduced carbon footprint).

Recommendation 2: Ownership of new gas plants and storage facilities by DSOs

- The legal framework regarding the conditions under which TSOs/DSOs may be allowed to own or operate a new gas plant should be clarified. Clarity is also required for storage facilities and their regulation as Article 33 of the Gas Directive infers to storage connected at transmission level.
- Concerning the ownership and operation of new-gas production facilities, we note that in general it is preferable for such activities to be developed under market conditions by gas producers/suppliers and not regulated monopolies.
- The ownership and operation of production facilities by system operators could be developed under two models. One is that of a vertically integrated undertaking that owns and operates the facility and the produced gas. This for example can be the supply branch of a DSO with less than 100,000 customers. Another model could be that of a fully unbundled system operator, that owns and operates the facility and offers a conversion service to independent third parties. Such service maybe the conversion of biogas to biomethane or electricity to gas (P2gas plants). In the latter business model, third party access rules and close monitoring by the regulator shall be required.
- In our view it is important that in a future update of the Gas Directive the specific activity is defined (e.g. new-gas production or conversion as noted above and then to clarify who shall be allowed to undertake such activity as a production or as a conversion service). For unbundled DSOs with over 100,000 customers, an exemption

could be foreseen only under special market conditions e.g. to kick-start the market and for a limited period of time (analogy to the framework for electricity storage).

- In all cases where a DSO becomes involved in a new-gas plant, there should be strict accounting unbundling between the remaining activities of the system operator and its activities as an owner and/or operator of the gas plant.
- NRAs should issue relevant guidelines, monitor the process and report status in a special new Section in their national reports submitted to CEER and the Commission. Indicatively such a separation should at least require balance sheets and a profit and loss account for each activity separately. Article 31(3) of Directive 2009/73/EC should be appropriately modified in a future amendment of the Directive.
- In the case where the framework allows for a new-gas plant to be developed and operated in whole or in part by a system operator, regulated access should be ensured through standardised contacts and regulated tariffs. The cost of the plant should be borne by the plant users and not by end-customers of the distribution network. A procedure for the allocation of capacity resembling the incremental capacity process of EU NC CAM and the respective economic test may be considered.

Recommendation 3: Monitoring of new-gas production facilities and new gas production

- Reliable fundamental data on gas production facilities in place and planned should be systematically collected by TSOs, DSOs and issuing bodies of guarantees of origin and reported to the national regulator.
- NRAs should monitor new gas facilities including connection times, actual production output, shareholding structure, business model and market participation. A regular reporting mechanism should be foreseen and introduced at EU level.
- The Commission (or ACER) may consider issuing a progress report on new gas facilities planned, installed and operating at each Member State including their business model on an annual basis. A choice of metrics to evaluate progress in new gas installations.

Recommendation 4: Facilitating VTP access for new-gas producers and suppliers

- The Gas Target Model aims at facilitating the creation of a well-functioning EU market, consisting of national or cross-border interconnected entry-exit zones with virtual trading points. However, a number of Member States have still either not implemented a functioning gas hub or the hub is illiquid with only very few transactions. In parallel, the introduction of new-gas production at distribution level shall gradually require the effective integration between transmission and distribution systems, and the update of market access rules.
- Physical and commercial flows should be further decoupled. Functioning hubs allowing access of all interested parties, including new-gas producers and suppliers regardless of the network they are active in (transmission/distribution), should be further developed. The Commission may further consider issuing a recommendation to Member States in this direction.
- Monitoring of the gas wholesale market by ACER should be further expanded to include new gas traded at VTPs and access conditions to VTPs.

Recommendation 5: Facilitating a competitive retail market

- Member States should initiate actions towards building consumer awareness regarding new-gases and their benefits (reduced carbon footprint, RES source, reduction of import dependency if produced within the EU). The Commission may have a role in this direction.
- Member States should ensure that all customers are free to purchase gas, including new gases from the supplier of their choice and further ensure that customers are free to have more than one gas supply contracts at the same time, provided that the required connection and metering points are established.
- Customer switching should be further facilitated. Member States should ensure that at least household customers and small enterprises are not charged any switching-related fees.
- NRAs should monitor switching processes including switching to different products (including products comprising new gases). Where relevant, monitoring of switching to different sources of heat, including to/from district heating should also be considered. NRAs should look into the overall terms and conditions of services and contracts offered by suppliers and fees for early termination. There may be a need to include such obligations at EU level.
- There may be a scope for the Commission to mandate a detailed more detailed template for reporting on retail gas market terms and conditions across Member States. Penetration of new-gas products and customer switching to products containing gases of reduced carbon content should be monitored, while relative metrics to evaluate progress and quantify barriers should be developed. NRAs should be assigned an obligation to closely monitor such metrics and undertake actions if a certain minimum threshold is not met.

Recommendation 6: Registration, licensing and technical requirements

- Member States that require authorisations or other type of licensing for the installation, construction and operation of new-gas production facilities should have the appropriate framework promptly in place. A deadline for the adoption of such a framework (e.g. 2023) may need to be introduced at EU level.
- Wholesale and retail trading will have to be further facilitated. In this context, the Commission may need to evaluate the implications of introducing a system of mutual recognition of licenses (particularly wholesale licenses) across Member States. Barriers in retail licensing should be investigated.
- Member States should ensure that all DSOs conclude with an evaluation on the percentage of hydrogen that can be accepted by their networks without additional investments and on a cost-benefit analysis on additional levels of hydrogen that may be accommodated by a specific deadline (e.g. 2023). A commitment at EU level may be required.
- Timescales referenced here (e.g. 2023) are only indicative and should be subject to further assessment.

Recommendation 7: New role and tasks of the DSO

Gas quality

- DSO should be assigned with specific responsibilities on gas quality monitoring and on taking actions when quality is not of the anticipated standards.
- Distribution system operators should monitor gas quality in their distribution systems and should develop appropriate methodologies to calculate the quality of gas delivered to end consumers.
- Costs borne by the DSOs for the installation of smart gas quality sensors, when these become commercially available, would need to be remunerated through tariffs. Such smart quality sensors shall need to be installed at least at network branches where mixing between different quality branches takes place and potentially also upstream certain selected consumption points. Exact installation locations should be subject to a detailed study including modelling of gas mixing and taking into account related costs versus benefits.
- There may be a scope for the establishment of a platform to include all competent authorities for gas quality by Member State.
- DSOs may consult with final consumers and suppliers active on their networks and collect information on the connected appliances and their operating margins. As a second step they may consider preparing a list of parties that need to receive information on gas quality in a similar manner as provided by EU NC IA for transmission.
- DSOs should be assigned with a responsibility to investigate costs and technical requirements for the removal of odourisation for gases to enter transmission. Such an investigation however may be also carried out also in collaboration with the various associations active at European level or the EU gas DSO entity (see below).

Connection requirements

- DSOs should provide new-gas producers wishing to connect to the distribution network with sufficient information on connection rules, available capacity, costs, timing and quality of gas accepted.
- Each DSO should develop rules for the connection of new-gas facilities to the network, standardised connection agreements and a methodology for the estimation of connection costs. The rules shall not discriminate between new gas facilities and technologies employed.
- DSOs, in coordination with upstream TSOs, where necessary, should develop a methodology for the calculation of available capacity per pressure level to accommodate the injection of new gases without the addition of compression to transmission. The methodology and available capacity for the next 18 months.
- Distribution system operators should develop all relevant rules regarding capacity allocation to new gas facilities.
- All documents above shall be subject to regulatory approval following public consultation and published at the DSO website.

Network Development

- DSOs should prepare a network development plan for the next at least 5-years and submit it to the NRAs for approval following public consultation. The plan should consider the connection of new gas facilities, provision of linepack services and also the potential for reverse flows to the transmission system. National frameworks would need to be modified to include such an obligation.

- In their development plans, DSOs should consider a range of available alternative solutions that could lead to the reduction of reinforcement costs, as well as the reduction of gas losses, should be considered. This includes using innovative technologies where efficient, and considering build or non-build solutions (i.e. solutions that avoid network expansions by demand side management and/or efficient use of linepack) which may be offered by other parties or at other pressure levels, to ensure that the most efficient investment option is taken forward across the system.
- In the development plan, DSOs should also include a long-term gas quality outlook for their distribution system and identify potential trends of gas quality parameters and respective potential variability within the next 5 years. The long-term gas quality monitoring outlook shall cover at least the Wobbe-index and gross calorific value. Additional gas quality parameters may be included following consultation with new-gas producers, end consumer organisations, manufacturers of equipment and other stakeholders.

Network Operation

- Distribution system operators should cooperate with transmission system operators for the effective participation of new-gas facilities connected to their grid in retail, wholesale and balancing markets, the development of capacity on their common interconnection points and for issues related to the interoperability of their systems including gas quality.
- The distribution system operator shall collect and publish gas quality data and pressure in their networks and shall provide NRAs information on all new gas plants connected to its system in terms of technology, production capacity, monthly production and connection date.
- DSOs should also cooperate with TSOs in order to efficiently operate their systems and ensure the necessary system flexibility, including through reverse flows (physical or commercial) and storage options.

Recommendation 8: Network Operation and Flexibility

We don’t see an immediate need for DSOs to provide commercial linepack services however, linepack should be gradually calculated and published for transparency and regulatory reasons (also for assessing connection/access and also injection refusals). Recommendations in this direction are provided below.

- DSOs should:
    - Calculate the average, minimum and maximum levels of linepack within the day for heating and the non-heating seasons. This information should be published.
    - Optimise the use of the linepack so as not to refuse the injection of new gases. Report to the NRAs on the actions taken.
    - Inform the NRA upon all refusals to accept the injection of new gases on one or more days due to existing high pressures in the network.
    - If necessary, design and submit to the Regulator for approval a linepack flexibility service, after consultation with the network users.

    - Submit to the Regulator investment requests related to the optimisation of the use of the linepack. Investment requests should be accompanied by a cost benefit analysis.
    - Consider offering linepack as a service to network users, if necessary, and develop appropriate rules and tariffs.
- NRAs should:
    - Collect information submitted by the DSO. Monitor the use of linepack and report relevant information regarding its utilisation and services offered by the DSO in their annual report submitted to CEER and the Commission.
    - Be responsible of approving the linepack flexibility service and relevant tariffs if proposed by the DSO.
    - Assess all investment requests through a cost-benefit analysis.

The following are also noted:

- Gas TSOs and DSOs should collaborate for the everyday operation of their interconnected systems.
- Gas DSOs and electricity operators should collaborate regarding the operation of the P2Gas plants connected at distribution level.
- An obligation for the TSO to accept physical reverse flows from distribution provided that these meet quality specifications would need to be introduced at the national framework.

Recommendation 9: Network Planning and DSO/TSO coordination

- Gas DSOs should consult with all relevant system users including current and potential new-gas producers and upstream TSOs on the network development plan. DSOs should be obliged to publish the results of the consultation process. The plan should be submitted to the NRA for approval, the NRA may request amendments to the plan.
- DSOs and TSOs should coordinate for the preparation of their development plans. Where network models are used these should be common where possible, including at least the assumptions underpinning these network models.
- DSOs and TSOs shall cooperate to produce demand scenarios and injection forecasts to transmission. DSOs should share information on connected capacity of new gas facilities and also information on projected connected capacity in the mid and long term as well as information on the ability of the distribution network to accept new gas injections on a seasonal basis.
- When developing network plans, DSOs and TSOs should consider the interactions between the electricity, gas, heating and cooling systems.
- DSOs and TSOs should collaborate with each other, as well as with public authorities and other stakeholders on a local and regional level, in order to ensure full coherence between network planning exercises and other relevant developments including local and regional urban planning.
- Proposals for the installation of compressors that would enable reverse flows from distribution to transmission should be subject to cost benefit analysis and should be considered after the maximisation in the use of existing linepack in distribution. Gas TSOs and DSOs should collaborate to determine the elements of the cost benefit analysis and may need to proceed jointly on a demand assessment for reverse capacity. The ENTSOG CBA methodology developed in the context of Regulation (EU) 347/2013

may be used as a base although further modifications may be required to account (e.g. costs to be borne by distribution system operator for other upgrades within the network to accommodate the new gas versus the installation of the compressor, monetised cost of curtailing new gas production if it cannot be absorbed by the system, relative benefits from the injection of new gases).

Projects related to the installation of compressors for physical reverse flows from distribution to transmission may be treated as incremental capacity projects and realised subject to firm commitments from interested parties along the lines of Regulation (EU) 2017/459.

If the capital and operational cost of compression is not borne by the users of the reverse flow, clearly it would need to be shared between TSOs/DSOs and ultimately borne by the end-consumers of the two systems. A base for cost sharing is already available from the cross-border cost allocation process of Regulation (EU) 347/2013. Further analysis is necessary also in the context of a long-term scope of integration between transmission and distribution. Such analysis may need to be undertaken at EU level to ensure no deterioration of the internal markets and the creation of barriers to cross-border flows.

Recommendation 10: Closed Distribution Systems and hydrogen networks

- Decarbonisation of energy intensive industries is an ongoing process. Energy intensive industries, which are currently also the owners and operators of closed hydrogen systems, should be facilitated in the installation of new-gas facilities that contribute towards decarbonisation.
- Limited reporting obligations should be also imposed upon closed networks in relation to their capacity, network length, customers' services, types of customers connected, types of gases in the networks and that they report on the storage or P2X facilities developed.
- In a possible future framework for hydrogen, when and if hydrogen networks grow to serve multiple customers, then they should be subject to regulation as is the case with natural gas networks.

Recommendation 11: The role of the NRAs

- The role of NRAs regarding monitoring of new-gas facilities and their interaction of the DSOs should be strengthened. NRAs should act as facilitators to new-gas producers as they are also new entrants to the market. The role of the NRAs should be strengthened in the following direction.

  Tariffs and Tariff Methodologies: NRAs should make publicly available the methodology for the calculation of connection charges imposed upon new-gas facilities and all underlying cost items. A relevant provision may be included in a future revision of the Gas Directive. Provisions for innovation and energy efficiency should be also included in the legal framework (including a future amendment of the Gas Directive) and the tariff methodologies.

  Capacity allocation and congestion management: NRAs also approve rules for capacity allocation and congestion management in relation to new gas injections.

  Development plan: NRAs should approve the development plan of the DSO, monitor its implementation and supervise the cooperation between TSOs and DSOs as well as the cross-sectoral cooperation between the operators of the gas and electricity sectors.

Monitoring: NRAs should monitor and assess the performance of distribution system operators based on a limited set of indicators, and publish a national report every two years, including recommendations. They should also monitor connection and injection refusals and the use of linepack at the distribution network. Level and effectiveness of market opening and competition at wholesale and retail levels, including the penetration of new gases and switching rates should be also monitored.

Recommendation 12: Drivers to innovation and incentives

- Recommendations offered by CEER[149] could be incorporated in a recommendation by the Commission to NRAs.
- Incentive regulation for gas DSOs supporting research and innovation projects should be promoted at EU level and gradually incorporated in the legal framework of Member States.
- Additional high-level common principles ensuring that network tariffs are non-discriminatory, reflect network costs associated with the use of the system, promote innovation and are capacity based where possible may also be incorporated in a guidance towards NRAs. It was also suggested that regulators consider the trade-off between CAPEX and OPEX at national level when incentivising innovation.

Recommendation 13: Tariff methodologies and tariffs

The Commission may consider issuing a recommendation to Member States along the following principles

- By analogy to the transmission service defined in EU NC TAR, it may be useful to define the definition of the distribution service i.e. the regulated service that is provided by the DSO within its distribution network for the purpose of transport.
- The distribution service should be distinct to other services provided by DSOs.
- Tariffs for the distribution service should be distinguished from other services provided by the DSOs (regulated or non-regulated).
- A transparent and cost reflective methodology for the evaluation of connection charges based also on a benchmarking analysis (or a unit investment cost reference) may serve towards increasing market confidence and remove any potential barriers to entry.
- A transparent and cost reflective tariff methodology for firm (and interruptible) capacity reservation for the injection of new gases to distribution system taking also into account seasonality factors and factors for non-yearly standard capacity products could be required subject to increased new gas penetration levels.
- Obligations for periodic consultation with stakeholders and obligations for transparency.

Recommendation 14: Participation of DSOs at EU institutional level

A scope towards the establishment of an EU DSO entity for gas has been identified by the participants to the 2019 CEER public Consultation and also by interviewees in this study. Decarbonisation of gas sector and introduction of new gases at distribution level should be facilitated by European DSOs in a coordinated manner. To this end, sharing

[149] See footnote 58

of best practices and formal participation of DSOs at the EU institutional level should be enabled. A gas EU DSO entity may also serve as a platform for discussion on topics related to available capacity, linepack and flexibility and quality at DSO level across Member States and also as a platform for discussion with the respective electricity EU entity on additional topics related to sector coupling and also more specific topics such as data management and data formats where needs and requirement are similar for both sectors. If network codes on these topics are developed, clearly gas and electricity DSOs should be also involved side-by-side.

Recommendation 15: Data management and procedures for access to data

- Consider a formal involvement of DSOs (both electricity and gas) in a future network code targeting cybersecurity and, data management.
- Articles 23, 24 and 34 of Directive (EU) 2019/944 provide a useful framework for data management and access to data also for the gas sector. Relevant provisions should also apply to gas DSOs.

Recommendation 16: Third party access, capacity allocation and congestion management

- A study on existing tools and mechanisms (e.g. hydraulic simulations, forecasted injection scenarios for production facilities, historical off take profiles etc) used by DSOs to establish the available capacity of their network should be carried out. Such study can subsequently lead to a high-level recommendation on basic principles for the estimation of available capacity.
- Reinforcements of distribution networks and the installation of compressors to transmission should be subject to a cost benefit analysis and an economic test along the line of Article 22 of EU NC CAM.
- There may be a scope in the implementation monitoring conducted by ACER according to Article 38 of EU NC CAM, to also assess whether misalignments in the capacity allocation procedures between interconnection points to EU Member States and national points (including exits to distribution networks) cause barriers to the allocation (and maximum utilisation) of capacity at distribution level. It is noted that this is a general recommendation and is not solely related to new gases.
- DSOs should determine and publish available capacity at distribution level and report to NRAs refusals of connection or capacity allocation to new gas facilities and the grounds for such refusals.
- DSOs should also report to NRAs cases where they refused the injection of new gases into the network due to operational issues. At a future stage there may be a scope of considering interruptible contracts or injection management procedures.

Recommendation 17: Balancing

- The operation of new-gas facilities is expected to be to a large extent continuous whereas demand at distribution level is highly seasonal. Substantial daily variations are also noted. Our review of national cases in the context of this study has shown that a number of Member States have already adopted more flexible balancing rules applicable to new-gas producers. Further discussion on this topic between DSOs, new-gas producers and NRAs may be necessary in countries where provisions are not in place.

Recommendation 18: Transparency

- It is recommended that regulators should initiate procedures for the development of a transparency template for DSOs related to the connection of new gas facilities. Harmonisation of the template across Member States will be useful also for the purposes of subsequent monitoring by the Commission and ACER. A task force in the CEER may undertake the coordination process.
- An obligation for all entities that want to develop a new-gas facility to notify the regulator on what the output product will be, the output capacity, their location (stored in a GIS system), the technology used and on the anticipated schedule of implementation should be inserted in the legal framework at EU level. A standardised project fiche should be developed, possibly harmonised across Member States. Relevant information may also be included in the national development plants of transmission system operators.

Recommendation 19: TSO/DSO cooperation

- The EU and national frameworks should provide for cooperation between gas transmission and distribution operators and electricity and gas operators (transmission and distribution) to ensure both efficient infrastructure planning and coordinated everyday operation.
- There may be a scope for national regulators to consult with gas TSOs and DSOs on current operational cooperation mechanisms and on the gaps and challenges they foresee in case of injection of new gases in distribution.
- NRAs may require TSOs in the context of their ten-year network development plan, to evaluate the potential of physical reverse flows of odorised gases from distribution to transmission and draw a plan of actions. Results of research work with new sulphur-free odorants and other type of odorants that do not need to be removed at transmission level should be investigated together with associated costs.

Appendix 1 By Article Review of Directive 2009/73/EC

Preamble	Title	Evaluation	Recommendations
(26)		It is only in the preamble that a provision for Member States to take measures to assist the wider use of biogas and gas from biomass is included. It also foresees for the biogas/biomass producers to be granted non-discriminatory access to the gas system. Compatibility to technical rules and safety standards on an ongoing basis should be assured.	Scope should be extended to biomethane, hydrogen and other new gases that contribute to the EU decarbonisation commitments.
(41)		Once again in the preamble there is a general recommendation for Member States to ensure that, taking into account the necessary quality requirements, biogas and gas from biomass or other types of gas are granted non-discriminatory access to the gas system, <u>provided such access is permanently compatible with the relevant technical rules and safety standards</u>. Those rules and standards should ensure that those gases can technically and safely be injected into and transported through the natural gas system and should also address their chemical characteristics.	Lack of technical rules and safety standards in a Member State can be a barrier to entry (barrier to connection of new facilities). There may be a scope, in a revised version of the Directive to introduce an obligation upon Member States stating that for example by 2025, all DSOs will conclude an evaluation on the % of hydrogen that may be accepted by their networks without additional investments and on a cost-benefit analysis for additional levels of hydrogen that may be accommodated. The FCH JU funded project HyLaw[150] has comprehensively concluded for example that the regulatory landscape with respect to allowed hydrogen admixture levels (which are defined in national gas quality standards) among Member States is very fragmented. Only nine countries have a regulation defining specific hydrogen admixture limits. Among those, Germany allows the highest rate of up to 10 vol%, whereas the majority of countries has limits of ≤1 vol%. It is clear that relevant quality standards would need to be defined to ensure

[150] https://www.hylaw.eu

Preamble	Title	Evaluation	Recommendations
			that a connection request is not rejected on the grounds of gas quality. These in turn are inherently related to the pipeline and auxiliary equipment material. Marcogaz, in the context of the preparations for the 33rd Madrid Forum has made available an infographic [151] showing test results and regulatory limits for hydrogen admission in existing natural gas infrastructure and end use. Further studies ay be required. There maybe also a scope, particularly with Member States that are not yet developing such facilities to include a timeline to take all necessary actions so that these facilities can be licensed, constructed and eventually become operational. ▪ A number of reviews (e.g. HyLaw and references therein, also STORE&GO project[152]) conclude that often the legal framework does not provide for a comprehensive definition of facilities producing new gases. Absence of proper definitions may cause problems in the licensing of such facilities in Member States where licensing is required. Directive 2018/2001 provides (Article 15, rationale (43,44)) for the Member States to apply administrative rules facilitating the rapid deployment of RES facilities. Clearly new gases production facilities that are non-RES do not benefit from such provisions.

[151] https://ec.europa.eu/info/sites/info/files/energy_climate_change_environment/events/documents/02.c.03_mf33_background_-_marcogaz_-_infographic_hydrogen_admission_-_j_dehaeseleer_g_linke.pdf
[152] Legislative and Regulatory Framework for Power-to-Gas in Germany, Italy and Switzerland, Store&GO project, https://www.storeandgo.info/

Article	Title/Topic	Evaluation	Recommendations
1	Subject Matter and Scope	The Directive is applicable to natural gas, including LNG, and in a non-discriminatory way to biogas and gas from biomass or other types of gas in so far as such gases can technically and safely be injected into, and transported through, the natural gas system.	By virtue, provisions and obligations also apply to new gases. There may be a scope introducing a direct reference to biomethane, synthesis gas and hydrogen. As commented above it is more crucial that the relevant technical and safety standards are defined so that there the operators cannot refuse access.
2			There may be a scope of introducing definition for "new gases" and for "new gases production facilities". New gases production facilities may request (from the relevant national body) the issuance of guarantees of origin to demonstrate the carbon footprint of each unit of energy of gas produced and also on whether it is renewable or not.
2(2)		The upstream pipeline network is defined as any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal.	The definition is adequate. It can also cover the scope of a gathering system i.e. a number of biogas producing plants connected to a gathering pipeline that transports biogas to a biomethane plant.
2(15)		The definition of linepack excludes facilities reserved for transmission system operators carrying out their functions. No similar provisions for distribution operators is in place.	There may be a scope for the Commission to initiate a discussion with relevant associations of distribution system operators to better comprehend the use of the linepack and the current national provisions
2(29)		'wholesale customer' means a natural or legal person other than a transmission system operator or distribution system operator who purchases natural gas for the purpose of resale inside or outside the system where he is established;	A new-gas producer may also be a wholesale customer.

Article	Title/Topic	Evaluation	Recommendations
3(6)	switching	This paragraph refers to supplier switching. The Gas Directive imposes upon Member States the obligation to ensure that (a) where a customer, while respecting the contractual conditions, wishes to change supplier, the change is affected by the operator(s) concerned within three weeks; and (b) customers are entitled to receive all relevant consumption data.	We are recommending for the Commission to consult on the need for further provisions to facilitate customer switching and to consider a scope for the introduction of a provision similar to the one of Article 4 of Directive (EU) 2019/944. For the case of gas can be adapted to state that "Member States shall ensure that all customers are free to purchase gas, including new gases, from the supplier of their choice and shall ensure that all customers are free to have more than one gas supply contracts at the same time, provided that the required connection and metering points are established". CEER in a series of papers[153] continues to identify barriers in the functioning in the retail energy markets and calls the NRAs for continuous market monitoring and assessment based on a standardised toolbox The CEER had identified two groups of commercial barriers to switching: (1) Barriers that influence customer perception about the energy market caused by incomplete, complex and non-comparable information on prices, contract conditions and market processes; and (2) Barriers resulting from commercial contract conditions that lead to customer lock-in (insufficient monetary gain Lack of trust Complex switching process Satisfaction/loyalty Commercial contract conditions Unjustified termination fees Value added services) We make further recommendations regarding the role of the NRA as a facilitator to customer switching for the particular case of new cases also in our review of Article 41.

Article	Title/Topic	Evaluation	Recommendations
3(7)	Measures for combating climate change	The article calls upon Member States to implement appropriate measures to achieve the objectives of social and economic cohesion and environmental protection, which may include means to combat climate change, and security of supply.	The article could be expanded to include a specific reference on new gases and energy conversion facilities (new gas production facilities).
3(12)	Energy consumer checklist	The Commission established in 2013 an energy consumer checklist as provided in paragraph 3(12) of the Directive.	The checklist will need to be revised to include information on new gases. A specific reference in the Directive could be made
4	Authorisations		To consider addition a new paragraph stating that in circumstances where an authorisation (for example, licence, permission, concession, consent or approval) is required for the construction or operation of new gas facilities, the appropriate legal framework should be put in place by 2025 and that Member States or any competent authority they designate may also grant authorisations to new gas facilities on the same basis that authorisations for other gas facilities are granted. Paragraph 3 should be specifically modified to refer to new gases and refusals for the connection of new facilities should be notified to the NRA.

[153] For example, Performance of European Retail Markets in 2017 (C18-MRM-93-03), Roadmap to 2025 Well-Functioning Retail Energy Markets (C17-SC-59-04-02), CEER Report on commercial barriers to supplier switching in EU retail energy markets (C15-CEM-80-04)

Article	Title/Topic	Evaluation	Recommendations
5-7	Monitoring of security of supply, Regional solidarity, Promotion of regional coopera-tion		No changes
8	Technical Rules		Proposal to add that the regulatory authorities where Member States have so provided or Member States shall ensure that "by 2025 all DSOs shall con-clude with an evaluation on the percentage of hy-drogen that may be accepted by their networks without additional investments and on a cost-benefit analysis on additional levels of hydrogen that may be accommodated" should be included in this Article or in another more suitable place in the directive
9-23	TSO, stor-age and LNG un-bundling provisions		No changes; no scope can be established at this stage for extending the certification procedure to DSOs. Careful monitoring by the regulators should ensure that unbundling requirements are met and that switching is not inhibited.

Article	Title/Topic	Evaluation	Recommendations
24, 25(3)	Tasks of distribution system operators	3. Each distribution system operator shall provide any other distribution, transmission, LNG, and/or storage system operator with sufficient information to ensure that the transport and storage of natural gas takes place in a manner compatible with the secure and efficient operation of the interconnected system.	To add in the list of the new-gas producer so that the paragraph reads as “. Each distribution system operator shall provide any other distribution, transmission, LNG, *new-gas producers* wishing to connect to its n*etwork* or already connected to the distribution network and/or storage system operator with sufficient information to ensure that the transport and storage of natural gas takes place in a manner compatible with the secure and efficient operation of the interconnected system.
25(4)	Tasks of distribution system operators	4. Each distribution system operator shall provide system users with the information they need for efficient access to, including use of, the system.	Provision is adequate as is. In Art 2(23) a system user is defined as a natural or legal person supplying to, or being supplied by, the system and thus incorporates also the new-gas producer.
25 (and art. 31(4) of the NED)	Tasks of distribution system operators	*Evaluation from text in Directive (EU) 2019/944* 4. Member State may require the distribution system operator, when dispatching generating installations, to give priority to generating installations using renewable sources or using high-efficiency cogeneration, in accordance with Article 12 of Regulation (EU) 2019/943.	In gas there is no dispatching. This provision is non-applicable for natural gas. Some priority rules could be provided in secondary legislation regarding nominations (in case of congestion), allocation, balancing (e.g. if responsibility for balancing is upon DSOs they should be using new gases). We do not recommend the including of such provisions in EU level. In all cases care is needed in implementation if any so that they do not distort competition. It is important for the DSOs to develop a set of rules for the connection of new-gas production facilities to the network

Article	Title/Topic	Evaluation	Recommendations
25 (and art. 31(5) of the NED)	Tasks of distribution system operators – *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 5. Each distribution system operator shall act as a neutral market facilitator in procuring the energy it uses to cover energy losses in its system in accordance with transparent, non-discriminatory and market-based procedures, where it has such a function.	This provision can be included in a future revision of the Gas Directive. A provision stating that, in order to reduce their own carbon footprint DSOs may decide to include the carbon footprint of the gas procured as an element to be taken into account in the market procedure process. Or Each distribution system operator shall act as a neutral market facilitator in procuring the energy it uses to cover energy losses in its system in accordance with transparent, non-discriminatory and market-based procedures, where it has such a function and also taking into account national and EU commitments towards addressing climate change.
25 (and 31(6) of the NED)	Tasks of distribution system operators *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 6 (a) Where a distribution system operator is responsible for the procurement of products and services necessary for the efficient, reliable and secure operation of the distribution system, rules adopted by the distribution system operator for that purpose shall be objective, transparent and non-discriminatory, and shall be developed in coordination with transmission system operators and other relevant market participants. (b) The terms and conditions, including rules and tariffs, where applicable, for the provision of such products and services to distribution system operators shall be established in accordance with Article 59(7) in a non-discriminatory and cost-reflective way and shall be published.	The Commission should consult as to whether there are other products and services that the DSO would need to procure in addition to gas for losses. Depending on the results of the Consultation, paragraph (a) may be incorporated as is. Paragraph (b) should be rephrased to read "The terms and conditions, including rules and tariffs, where applicable, for the procurement of such products and services to distribution system operators shall be approved by the NRA according to Article 41 in a non-discriminatory and cost-reflective way and shall be published". Paragraph b is also relevant to the paragraph in the cell above.

Article	Title/Topic	Evaluation	Recommendations
25 (and 31(7) of the NED)	Tasks of distribution system operators *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 7. In performing the tasks referred to in paragraph 6, the distribution system operator shall procure the non- frequency ancillary services needed for its system in accordance with transparent, non-discriminatory and market-based procedures, unless the regulatory authority has assessed that the market-based provision of non-frequency ancillary services is economically not efficient and has granted a derogation. The obligation to procure non-frequency ancillary services does not apply to fully integrated network components.	No changes for gas
25 (and 31(8) of the NED)	Tasks of distribution system operators *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 8. The procurement of the products and services referred to in paragraph 6 shall ensure the effective participation of all qualified market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation, in particular by requiring regulatory authorities and distribution system operators in close cooperation with all market participants, as well as transmission system operators, to establish the technical requirements for participation in those markets on the basis of the technical characteristics of those markets and the capabilities of all market participants.	Proposal to include rephrased as "The procurement of the products and services referred to in paragraph 6 shall ensure the effective participation of all qualified market participants, including new-gas producers. "

Article	Title/Topic	Evaluation	Recommendations
25 (and 31(9) of the NED)	Tasks of distribution system operators *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 9. Distribution system operators shall cooperate with transmission system operators for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets. Delivery of balancing services stemming from resources located in the distribution system shall be agreed with the relevant transmission system operator in accordance with Article 57 of Regulation (EU) 2019/943 and Article 182 of Commission Regulation (EU) 2017/1485 (24).	Proposal to include rephrased as 9. Distribution system operators shall cooperate with transmission system operators for the effective participation of gas conversion facilities connected to their grid in retail, wholesale and balancing markets and for the development of capacity on their common interconnection points
25 (and 31(10) of the NED)	Tasks of distribution system operators *From Electricity Directive*	*Evaluation from text in Directive (EU) 2019/944* 10. Member States or their designated competent authorities may allow distribution system operators to perform activities other than those provided for in this Directive and in Regulation (EU) 2019/943, where such activities are necessary for the distribution system operators to fulfil their obligations under this Directive or Regulation (EU) 2019/943, provided that the regulatory authority has assessed the necessity of such a derogation. This paragraph shall be without prejudice to the right of the distribution system operators to own, develop, manage or operate networks other than electricity networks where the Member State or the designated competent authority has granted such a right	It is proposed not to include the text.
25	New		New provisions in relation to the responsibilities of the DSO regarding gas quality and gas quality metering should be added.

Article	Title/Topic	Evaluation	Recommendations
26	Unbundling of distribution system operators	Directive 2009/73/EC already incorporates all unbundling provisions in included in the new electricity directive. The most recent report of the CEER (June 2019) on the status of unbundling does not identify any additional issues or barriers in relation to the distribution networks.	No changes are recommended. An issue for debate with stakeholders relates to the ownership of storage facilities.
27	Confidentiality obligations of distribution system operators	The article is adequate.	
28	Closed distribution systems	In the relevant Section of the NED (article 38) three additions have been made It was added that (a) closed distribution systems shall be considered to be distribution systems for the purposes of this Directive and (b) that Member States may provide for regulatory authorities to exempt the operator of a closed distribution system from: the requirement under Article 31(5) and (7) to procure the energy it uses to cover energy losses and the non- frequency ancillary services in its system in accordance with transparent, non-discriminatory and market-based procedures; the requirement under Article 6(1) that tariffs, or the methodologies underlying their calculation, are approved in accordance with Article 59(1) prior to their entry into force; the requirements under Article 32(1) to procure flexibility services and under Article 32(3) to develop the operator's system on the basis of network development plans; the requirement under Article	Hydrogen networks that have traditionally services the petrochemical industry can be considered as closed distribution systems. For as long as hydrogen networks remain confined in their role as private pipelines based on specific production agreements the current situation may be maintained. We would be recommending against adding the provision of the NED that closed distribution systems are distribution systems. Should this provision be added, privately owned hydrogen systems that service the industry should be allowed to own, operate and maintain a storage facility as provided for in the NED.

Article	Title/Topic	Evaluation	Recommendations
		33(2) not to own, develop, manage or operate recharging points for electric vehicles; and the requirement under Article 36(1) not to own, develop, manage or operate energy storage facilities.	
31(3)	Unbundling of accounts		In case that distribution system operators own or operate or maintain storage facilities or any type of conversion facilities then they in their internal accounting, keep separate accounts for each of the activities related to the storage or conversion facilities. The internal accounts shall include a balance sheet and a profit and loss account for each activity.
32	Third Party Access		To add in paragraph 1 that Member States shall ensure the implementation of a system of third-party access [..] <u>and new-gas producers</u> and applied objectively and without discrimination between system users.
33	Access to storage	Not applicable, the article refers to underground storage facilities connected to transmission.	Clarity regarding the applicability of Article 33 of the Gas Directive to distribution is needed.
34	Access to upstream pipeline networks	The article can also accommodate gathering networks	No identified needs for additional actions/modifications.
35	Refusal of access	Refusal of access to a transmission or a distribution system may be due to the lack of capacity or lack of connections. On a national level, system operators include provisions in the network codes where they state that they may refuse the transportation of off-spec gas.	No identified needs for additional actions/modifications.

Article	Title/Topic	Evaluation	Recommendations
		Clearly provisions would need to be included in distribution network codes where the national framework does not provide	
36	New infrastructure	The article refers to exemptions from unbundling requirements, third party access and tariff regulation of major infrastructure connected to transmission and typically of cross border impact	No changes.
37	Market opening and reciprocity	The article specifies the timescale until full market opening in 2007	No changes.
38	Direct lines		No changes.
39	Designation and independence of regulatory authorities		No changes.
40	General objectives of the regulatory authority	The directive already provides (Art 40e) that NRAs should facilitate access to the network for new production capacity, in removing barriers that could prevent access for new market entrants and of gas from renewable energy sources.	We would be recommending that the phrasing is modified to also account for gas of reduced carbon footprint and not just renewable gas.
41	Duties and powers of the regulatory authority	Paragraph (1.g) states that NRAs monitor investment plans of the transmission system operators and provide in its annual report an assessment of the investment plans of the transmission system operators as regards their consistency with the Community-wide network development plan.	The scope of paragraph 1g would need to be expanded (or a new paragraph added) to provide for monitoring of the plans of the DSOs. The scope of paragraph 1n should be extended here (and also in article 33) to refer also to linepack for distribution. The scope of paragraph 6 should be expanded to include approval of access conditions of

Article	Title/Topic	Evaluation	Recommendations
		Paragraph (1.n) states that NRAs monitor and review the access conditions to storage, linepack and other ancillary services as provided for in Article 33. Paragraph (6) states that The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for connection and access to national networks, including transmission and distribution tariffs, and terms, conditions and tariffs for access to LNG facilities Paragraph (8) mentions that transmission and distribution system operators should be granted with appropriate incentives. Paragraph (9) states that NRAs shall monitor congestion management of national gas transmission networks including interconnectors, and the implementation of congestion management rules. including capacity allocation, to the national regulatory authorities. National regulatory authorities may request amendments to those rules.	New gas facilities to the distribution network and approval of connection tariffs and tariff methodologies for connection. Also, for the NRAs to approve rules for capacity allocation and congestion management to distribution. The scope of paragraph 8 should be expanded to include provisions for innovation. The scope of paragraph 9 should be expanded or a new paragraph added to include monitoring of distribution networks, commercial use of linepack and congestion if any. NRAs should also monitor penetration of new gases in the distribution networks and the connection of New gas facilities to the network
42	Regulatory regime for cross-border issues		No changes.
43	Compliance with the Guidelines		No changes.

Article	Title/Topic	Evaluation	Recommendations
44	Record keeping		No changes
45	Retail markets		We recommend to also add a reference to energy conversion facilities producing new gases.
46	Safeguard measures		No changes
47	Level Play Field		No changes
48	Derogations in relation to take-or-pay commitments		No changes
49	Emergent and isolated markets		No changes
50	Review procedure		No changes
51	Committee		
52	Reporting	The Commission monitors and reports to the European Parliament and the Council on progress regarding the implementation of the directive	The Commission may also consider reporting on progress regarding the connection of energy conversion facilities producing new gases in Member States, the penetration of new gases in transmission and distribution networks, customer switching to new gases and blending levels achieved.

Article	Title/Topic	Evaluation	Recommendations
			The Commission may also report on specific actions regarding the cooperation of the EU electricity and gas DSO Entities.

Appendix 2 By Article Review of Regulation 715/2009

Article	Topic	Evaluation	Recommendations
1	Scope	The regulation establishes rules for setting harmonised principles for tariffs, or the methodologies underlying their calculation, for access to the network, the establishment of third-party access services and harmonised principles for capacity-allocation and congestion management. It determines transparency requirements, balancing rules and imbalance charges and the aims to facilitate cross border trading,	A focus of the Regulation is harmonisation of rules across distribution networks. It may be too early for a mandate for harmonisation across EUs thousands of distribution systems.
2	Definitions		
3	Certification of transmission system operators	The article addresses the procedure in relation to the opinion of the Commission for the certification of TSOs	As no certification procedure is foreseen for DSOs the article is not applicable
4-5	European network of transmission system operators for gas		No changes
6-7	Network codes (establishment and amendment)		No changes

Article	Topic	Evaluation	Recommendations
8	Tasks of ENTSOG	The article sets the tasks of ENTSOG	An obligation for cooperation with distribution system operators and the EU DSO entity, if established with competencies for gas, may be added.
9	Monitoring by the Agency		No changes
10	Consultations	The Article defines the consultation process on the draft network codes to be followed by ENTSOs. The article already provides that at consultation ENTSOG shall also involve national regulatory authorities and other national authorities, supply and production undertakings, network users including customers, distribution system operators, including relevant industry associations, technical bodies and stakeholder platforms.	No changes
11-12	Costs and Regional Cooperation	The articles refer to the costs to be borne by ENTSOG and to the establishment of regional cooperation within ENTSOG.	
13	Tariffs for access to networks	This article sets the principles for tariffs for access to transmission networks. The main principles underlined by the Regulation are: ▪ An obligation for the implementation of an Entry/Exit System ▪ Transparency considering the need for system integrity and its improvement	The question to be addressed here is whether a relevant article would be required to address distribution tariffs. Note that Article 41(8) of Directive 2009/73/EC already requires NRAs to: "Ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities".

Article	Topic	Evaluation	Recommendations
		▪ Cost reflectivity (with some benchmarking as the to ensure that costs correspond to those of an efficient and structurally comparable network operator) ▪ Ensure return on investments ▪ Non-discrimination ▪ Neither restrict market liquidity nor distort trade across borders of different transmission systems	Furthermore, the Directive 2012/27/EU (Article 15) states that: "Member states shall ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to overall efficiency (including energy efficiency) of the generation, transmission, distribution, and supply of electricity or those that might hamper participation of demand response, in balancing markets and ancillary services". Finally, in Annex XI of the Directive, it is stated that "network tariffs shall be cost-reflective of cost- savings in networks achieved from demand-side and demand-response measures and distributed generation, including savings from lowering the costs of delivery or of network investment and a more optimal operation of the network". It is moreover presented that "network regulation and tariffs shall not prevent network operators or energy retailers making available system services for demand response measures, demand management and distributed generation on organized electricity markets". From the above it is clear that the existing framework at EU level does not include specific principles for tariff design at distribution level but only general concepts subject to further implementation by Member States. Such basic concepts may be transparency, non-discrimination and cost-reflectivity. In principle Member States should include the incentive provision as it is part of the Directive. A further study to establish whether distribution tariff regulations in Member States already implement such provisions may be required.

Article	Topic	Evaluation	Recommendations
14-15 and Annex I (1)	Third-party access services concerning transmission system operators, storage and LNG facilities	Once again the regulation introduces general concepts for the provision of services : offers of firm and interruptible capacity and long- and short-term services under equivalent and non-discriminatory conditions based on standardised transmission contracts. Guarantees from network users with respect to the creditworthiness of such users. Such guarantees shall not constitute undue market-entry barriers and shall be non-discriminatory, transparent and proportionate The regulation also calls for standardisation of capacity products and contract durations as further implemented In Regulation (EU) 2017/459 and for the development of network codes. There are also provisions for compatibility between contracts offered for storage and LNG facilities and transmission	The country review (Section 0) has shown that standardised connection rules exist in most countries reviewed. We have not looked however in detail in relation to standardised connection contracts and guarantees. Firm capacity contracts are offed at least on an annual basis. Capacity allocation is typically on a first come first served basis with some countries the requirement of Article 35 of Directive 2009/73/EC also on new connections ("Natural gas undertakings may refuse access to the system on the basis of lack of capacity or where the access to the system would prevent them from carrying out the public service obligations"). In other cases, the implementation of this requirement is unclear. A recommendation to Member States and NRAs on the need for standardised connection contracts and clear rules for network access (and refusal of access) may be required.
16-17 and Annex I (2)	Principles of capacity allocation and congestion management	The Regulation introduces general principles for congestion management and specific rules to address contractual congestion. A core part of the congestion management rules is that they should ▪ facilitate the development of competition and liquid trading of capacity and be compatible with market mechanisms including spot markets and trading hubs ▪ provide appropriate economic signals for efficient and maximum use of technical capacity and ▪ facilitate investment in new infrastructure.	Typically, there are no congestion management rules at distribution level.

Article	Topic	Evaluation	Recommendations
18-20 and Annex I (3)	Transparency requirements concerning transmission, LNG and storage system operators and record keeping	The Regulation introduces several transparency obligations upon all system operators except distribution.	The scope of these transparency obligations is to provide easily accessible and concise information to interest parties so that they can book capacity at entry and exit points.
21	Balancing rules and imbalance charges	The Regulation calls for transparent, non-discriminatory market based balancing rules and places obligations upon TSOs to provide reliable on-line based information on the balancing status of network users so that they can take timely corrective actions. Imbalance charges shall be cost-reflective to the extent possible, avoid cross subsidisations and provide appropriate incentives on network users to balance their input and off-take of gas. Any calculation methodology for imbalance charges as well as the final tariffs shall be made public by the competent authorities or the transmission system operator, as appropriate.	
22	Trading of capacity rights		
23-32		n/a	

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