European Commission

Assessment of policies for gas distribution networks, gas DSOs and the participation of consumers

Final Report

Frontier Economics
August 2022

frontier economics

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We are grateful for further input provided by Walter Boltz.

EUROPEAN COMMISSION

Directorate-General for Energy
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Directorate-General for Energy

2022

Manuscript completed in 2022

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PDF ISBN 978-92-76-51629-3 doi: 10.2833/586205 MJ-08-22-113-EN-N

Luxembourg: Publications Office of the European Union, 2022

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INTRODUCTION

Deep decarbonisation in the EU energy sector is needed to achieve climate neutrality. The way we produce, transport and use energy will have to evolve. It is now widely accepted that renewable and decarbonised gases will be a key part of enabling decarbonisation.

Given the geographic distribution of renewable electricity and gas production potential, allowing injection of ‘alternative gases’ (as defined in the tender specifications) at distribution level could help to keep the costs of the energy transition to a minimum. But it also presents challenges, as the regulatory framework is not currently well-adapted to enabling the integration of distributed production and injection of alternative gases.

The Commission is seeking to elaborate on and evaluate potential options for reform of the current framework.[1] It requires a sound evidence base to do so. The focus lies on three topics:

- Topic I: DSO Tasks - Gas Quality Management;
- Topic II: Energy Communities in the gas sector; and
- Topic III: Consumer’s participation, smart metering systems

This report assesses the potential options that the Commission proposed for each of the three topics separately.

The final report is structured as follows.

- For each of the three topics above, we:
  - summarize the status quo and list potential problems that could occur with the current framework in place; subsequently,
  - describe the different policy options that the Commission proposed; and
  - analyse the costs, benefits and distributional effects associated with the options proposed.
- We append two Annexes that contain further information on Topics I and II, respectively.
- In addition, we attach one Annexe that provides insights into the experience outside the EU on the injection of alternative gases.

[1] The analysis presented in this study fed into the Impact Assessment for the Gas Decarbonisation Package. Most of the information was processed until the November 2021.

TOPIC I: DSO TASKS - GAS QUALITY MANAGEMENT

Problem definition and status quo analysis

The current European gas system has been configured based on the assumption that gas (of a broadly stable and homogenous quality) is primarily sourced from imports (both LNG and pipeline gas). The resulting flows are mainly from transmission through to distribution grids, with limited need today for active gas quality management.

The situation has started to change, and is likely to develop further:

- Given that much of renewable and low-carbon gas production is expected to be located at distribution level, DSOs may face increasing gas flow management challenges in order to optimise the use of the local injection potential. There may be even a case for increasing 'reverse' flows from distribution to transmission grids.[2]
- Renewable and low-carbon gases have different quality characteristics than natural gas. Figure 1 below compares the characteristics of natural gas to biogas and biomethane (but clearly hydrogen also has different quality characteristics to natural gas).

Figure 1 Properties of natural gas, raw biogas and biomethane

Gas composition	Biogas	Biomethane	Natural Gas
Methane	50 - 75%	94 - 99.9%	93 - 98%
Carbon Dioxide	25 - 45%	0.1 - 4%	1%
Nitrogen	<2%	<3%	1%
Oxygen	<2%	<1%	-
Hydrogen	<1%	Traces	-
Hydrogen Sulphide	20 - 20,000 ppm	<10 ppm	-
Ammonia	Traces	Traces	-
Ethane	-	-	<3%
Propane	-	-	<2%
Siloxane	Traces	-	-
Water	2 - 7%	-	-

Source: Ahmad, Nurjehan & Mel, Maizirwan & Sinaga, Nazaruddin. (2018). Design of Liquefaction Process of Biogas using Aspen HYSYS Simulation. 2. 10-15.

Certain gas system users (and the gas infrastructure itself) may be sensitive to changes in gas quality (for example, fluctuations in gas quality can lead to variations in flame length in burners in processes such as glass manufacturing, affecting efficiency and safety[3]). Given this, both distribution and transmission

[2] Frontier et al (2019) 'Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU - Final report', section 5.4.2.

[3] GWI (2020) "Prime movers' group on gas quality and hydrogen handling" p. 58 https://entsog.eu/sites/default/files/2021-02/Meeting%20November%202020.pdf

system operators are likely to need to manage flows in the grid, including at injection and withdrawal points, to ensure that gas quality conforms to agreed standards. It will be important that these activities are carried out cost-effectively to avoid excessive costs for grid users (who may ultimately bear a large share of the costs incurred).

Currently, there is an existing EU-level framework for managing cross-border gas quality differences (see Article 15 of the Network Code on Interoperability and Data Exchange Rules, or 'INT NC'[4]) and for some elements of gas quality management at transmission level. However, there is no EU-level framework governing the gas quality measurement, monitoring and management tasks to be undertaken by **gas DSOs**.

Despite the lack of an EU-level framework, some MS have implemented domestic regulations of gas quality measurement and monitoring by gas DSOs. Typically, the role of the DSO is limited to the monitoring of gas quality at injection points (and management of connections and/or injections), rather than more generally management of flows within the grid. In other MS, DSOs do not have a role in measuring and monitoring the gas quality (for more information about the role of the DSO in the different MS see Figure 18 in Annex A). As and when MS start to support the deployment of alternative gases, we would typically expect them to ensure an appropriate framework is in place for managing gas quality at distribution level, via national rules. However, there is a possibility this may not happen systematically.

This therefore creates risks (albeit uncertain in magnitude) that, going forward, costs associated with meeting decarbonisation and renewable energy goals may be higher than necessary due to some combination of some MS either:

- not adopting a regulatory framework for gas quality management at DSO level;
- not obliging DSOs to share relevant gas quality information with TSOs; or
- not ensuring that DSOs carry out gas quality management responsibilities cost effectively.

We discuss each of these risks further below. Overall, the need for EU-level co-ordination to address these risks may not be as strong at DSO-level (compared to at TSO level, where there are significant cross-border flows). However, given the possibility of 'reverse' flows from DSO to TSO level, EU-level intervention may indirectly help reduce barriers to cross-border trade that may arise with changes in gas quality and help the integration of renewable and low-carbon gases.

Risks of MS not adopting a gas quality management framework

In the absence of an EU framework there is the risk that national regulation will not be adopted, therefore not tasking/enabling DSOs to more actively engage in gas quality management. If DSOs are not tasked with managing gas quality, this might lead to alternative gas not being controlled and/or not injected, resulting in safety

[4] OJ L 113, 1.5.2015, p. 13–26.

and/or performance issues for grid users and infrastructure. Since certain users are sensitive to gas quality (see above), an inadequate gas quality may:

- increase costs to these users; or
- lead to increased system-wide costs associated with the mitigation actions of such users. For example:
  - Users may undertake individual gas quality improvement measures (while it may have been more cost-effective to address gas quality at system level); or
  - Users may be incentivised to disconnect from the gas grid (and produce their own gas or use an alternative energy carrier).

In practice, the above situation may not materialise since DSOs are tasked with ensuring that safety standards are met.[5] Instead, the lack of a domestic framework for managing gas quality could itself de-facto prevent the injection of alternative gases. Such a restriction could increase the costs of decarbonisation (assuming it would have otherwise been cost-effective to make use of the distributed potential for injection of alternative gases).

Risks of inadequate co-ordination with TSOs

Unmanaged gas quality coming from distribution level may increase the costs TSOs incur associated with managing gas quality. Even where DSOs are tasked by MS with managing gas quality, if they do not systematically share information with TSOs regarding all relevant gas quality parameters at relevant timescales, this may still undermine the ability of TSOs to manage gas quality cost-effectively at transmission level (including at interconnection points between EU countries).[6]

For example, if the earliest that TSOs receive information on gas quality from DSOs is at the point that gas enters the transmission system from the distribution system, TSOs will have fewer options available at short notice to keep gas quality within acceptable limits. In the extreme, TSOs may seek to prevent flows from distribution level to avoid the risk of breaching gas quality standards. If DSOs cannot take advantage of flexibility at transmission level, this may make both managing physical congestion and gas quality at distribution level more difficult, leading to increases in system operation costs or to reduced levels of integration of alternative gases at distribution level.

[5] Source: Frontier stakeholder interview with DSOs, June 9th 2021, view expressed by Austrian DSO Wiener Netze GmbH. In addition, according to the Gas Directive (Article 25(1)), "*[…] Each DSO shall be responsible for […] operating, maintaining and developing under economic conditions a secure, reliable and efficient system in its area [...]*".

[6] For example, under INT NC Article 17, TSOs may provide DSOs connected to their network (with final customers who may be affected by gas quality variations) with relevant information on gas quality variations.

Risks of higher-than-efficient costs of gas quality management

Finally, EU legislation sets high-level principles for network tariffs, tasking NRAs to fix or approve transmission tariffs or their methodologies.[7] According to the Gas Directive, NRAs shall ensure that network operators have '…*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*…'.[8] However, there is limited elaboration at EU level on what constitutes efficiently incurred costs and of the degree to which costs of managing gas quality might be recovered through tariffs. This raises the possibility that costs of managing gas quality may be higher than necessary. For example, one risk may be that, where integrated DSO/TSO network planning (and corresponding regulatory incentives for co-ordinated solutions) is not in place, DSOs may favour solutions that lead to building new infrastructure or maintaining existing infrastructure to address gas quality issues, even if alternative solutions (for example, through the purchase of ancillary services) may be more cost-effective.

Definition of policy options

- **Option 0**: Business as usual, no change in EU legislation addressing tasks for DSOs.
- **Option 1**: This option proposes to require DSOs to assume specific tasks related to the measurement and monitoring of gas quality. In addition, DSOs may assume a more active role in managing the gas quality in their networks. While the precise implementation of this option is still to be decided, the broad principle would be that these tasks would only apply where there is a need. This could be indicated, for example, by some of the following conditions:
  - where there are infrastructure or users sensitive to gas quality;
  - where the injection of alternative gases is taking place; and/or
  - where flows from distribution to transmission have been enabled.

Cost benefit analysis associated with gas quality measurement, monitoring and management

Overview

At a high level, EU intervention clarifying the responsibilities of DSOs with regards to gas quality measurement, monitoring and management may ensure that some Member States (that might not otherwise have done so) ensure DSOs manage gas quality cost-effectively and, in doing so, co-ordinate effectively with TSOs. If this is

[7] Article 13, 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, OJ L 211, 14.8.2009, p. 36–54.

[8] Article 41(8), 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, OJ L 211, 14.8.2009, p. 94–136.

the case, this may come with some additional **costs** (including the costs associated with monitoring and managing gas quality) and **benefits** (reduced costs of energy production and/or transport) compared to the counterfactual.[9]

Experience is as yet limited regarding active management of gas quality at DSO level, and there is therefore limited evidence to support quantified evidence of costs and benefits. However, there is a case for a positive overall net benefit:

- Provided Member States only assign gas quality management responsibilities to DSOs if deploying alternative gases (i.e. injection of renewable gases at distribution level); and
- Provided that Member States would only deploy alternative gases if, based on a forward-looking analysis, the benefits of doing so would outweigh the costs (including those associated with gas quality management); then
- The balance of costs and benefits should (at least, in expectation) be positive.

We describe the costs and benefits in further detail below. As noted above (see ‘Problem definition and status quo analysis’), the extent to which these costs and benefits will be additional, compared to the counterfactual, is uncertain. In addition, the precise combination of benefits that may occur depends on the counterfactual, which is also uncertain.

Costs

Costs of managing gas quality

These include a number of one-off and ongoing costs incurred at both DSO and TSO level (in the latter case, due to potentially increased co-ordination with DSOs).

One-off costs may include:

- Investments in infrastructure to assist with managing gas quality (for example, upgrades to pipelines to accommodate hydrogen blends or investments in storage infrastructure). Some of this might take place in response to price signals generated by DSOs through their purchases of ‘services’ to manage gas quality.
- capital spends to change DSO IT systems, install measuring facilities (smart quality sensors);
- other transformation costs for DSOs in the event of changes to team structures; and
- Administrative costs for DSOs, e.g. information sharing and reporting, for mapping their network to identify sensitive end-users.

Ongoing costs may include:

[9] In principle, there could also be impacts related to changes in emissions and/or renewables deployment. We make the simplifying assumption in our analysis that, under the counterfactual and all options, renewable and efficiency goals are met. We therefore focus on the extent to which the costs associated with meeting these goals might differ between options.

- labour costs to employ the required workforce (personnel responsible for measuring, monitoring and managing gas quality[10]) in the different entities;
- expenditures for maintenance; and
- operating costs associated with gas quality management, for example those involved with adjusting injections and/or withdrawals to ensure that gas quality standards or hydrogen blending targets are met.

In regard to the last category of costs above, their magnitude will depend on:

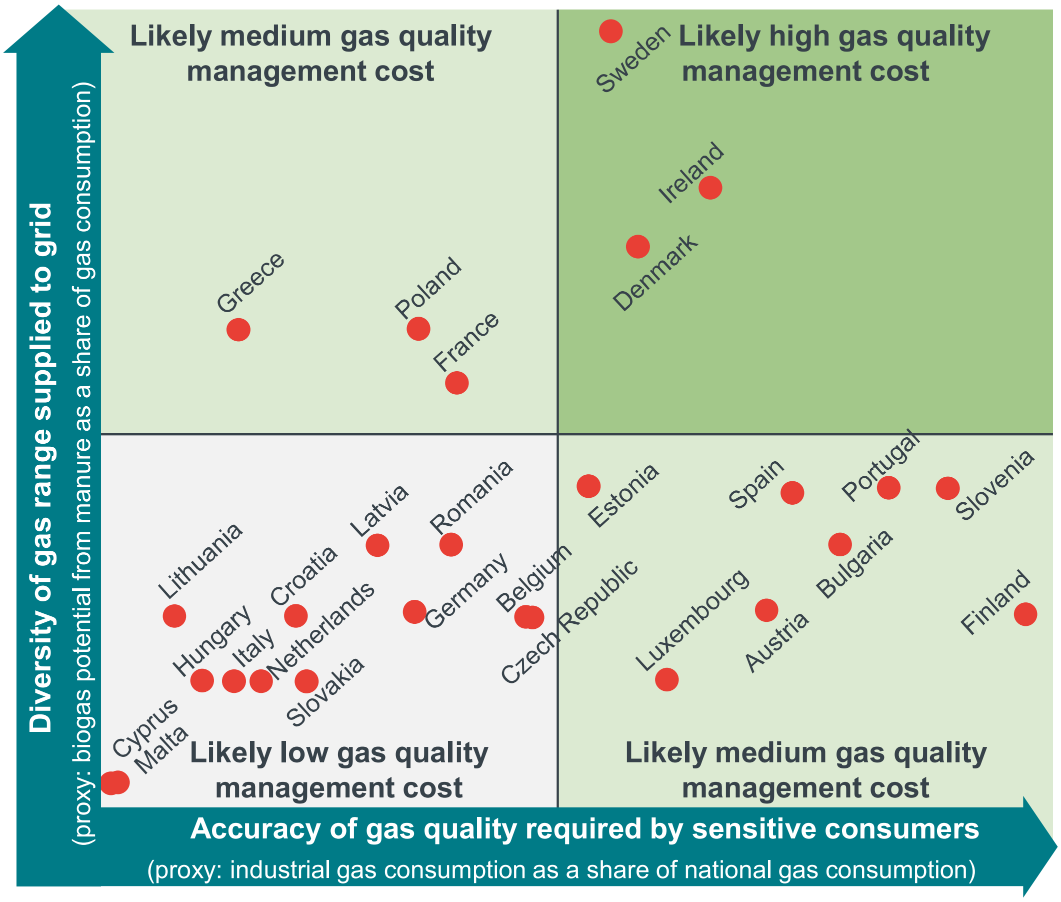
- the diversity of quality of gases being injected (the greater the diversity of gas types being injected, the higher the costs of keeping gas quality within acceptable limits), which itself will depend on the gas quality specification agreed for the system;
- the gas quality that is required at different exit points, including to the transmission grid (the greater the share of consumption from sensitive end-users and the more geographically spread out they are across the distribution system, the more actively gas quality must be managed, see Figure 2); and
- the incentives that grid users face. For example, the total costs of managing gas quality might be reduced if grid users (including producers) are exposed to the incremental gas quality management costs they impose on the system through their investment choices (e.g. where users choose to connect to the grid[11]) and their operational choices (e.g. when they choose to inject or withdraw)[12].

[10] In cases where gas flows from distribution to transmission level have been enabled this also includes the cost of exchanging the respective information on gas quality.

[11] Subject to the DSO accepting any connection request.

[12] Note that, in all these cases, as noted above, producers will need to adhere to gas quality specifications. However, depending on the exact quality of injected gases within the agreed quality range, this could result in greater or lower costs involved in ensuring the required gas quality at exit points.

Figure 2 Gas quality costs are likely to be higher where more sensitive industry users are dependent on a heterogeneous mix of renewable gases



Source: Frontier Economics based on Eurostat, see Annexe A.2.

Note: The matrix aims to illustrate where gas quality management cost (relative to national gas consumption) are higher based on the assumption that they are driven by the tension between, on the one hand, a wide diversity of gases produced and supplied to the grid, and, on the other, sensitive consumers requiring a specific gas quality. Due to data availability, we proxy for the presence of sensitive consumers by using industry gas consumption per Member State (as a percentage of each Member State's gas consumption), and for diversity of gas quality by biogas potential from manure (again as a percentage of each Member State's gas consumption).

While the indicators are based on national data, both the importance of industrial consumption and the diversity of gases could be higher/lower in certain parts of the network within each country.

Thresholds for the different quadrants: Countries with an industrial gas consumption share above 40% are allocated to the right quadrants; countries with a biogas potential from manure as a share of gas consumption above 5% are allocated in the upper quadrants.

Under this policy option:

- We assume grid operators are incentivised to consider the appropriate commercial framework (including the structure of connection charges and/or ancillary service payments) that would help to minimise costs, while being proportional to the level of challenge involved in managing gas quality.
- Costs are also minimised since TSOs would (more systematically than under the counterfactual) have relevant information related to gas quality coming from DSOs (in cases where flows from distribution to transmission have been enabled). For example, such information could better enable TSOs to plan ahead when managing gas quality. More generally, improved co-ordination

between TSOs and DSOs in managing gas quality may allow TSOs to better exploit low-cost flexibility options to manage gas quality located at DSO level (and vice versa).

Regulatory and enforcement costs

There will also be additional costs associated with regulation and enforcement:

- Increased monitoring costs to check that the gas measurement, monitoring and management requirements are met by the DSOs; and
- One-off (e.g. training and developing knowledge) and ongoing (e.g. personnel) monitoring costs to verify and assess the measurement, monitoring and management expenses that the DSOs include in their regulatory asset base.

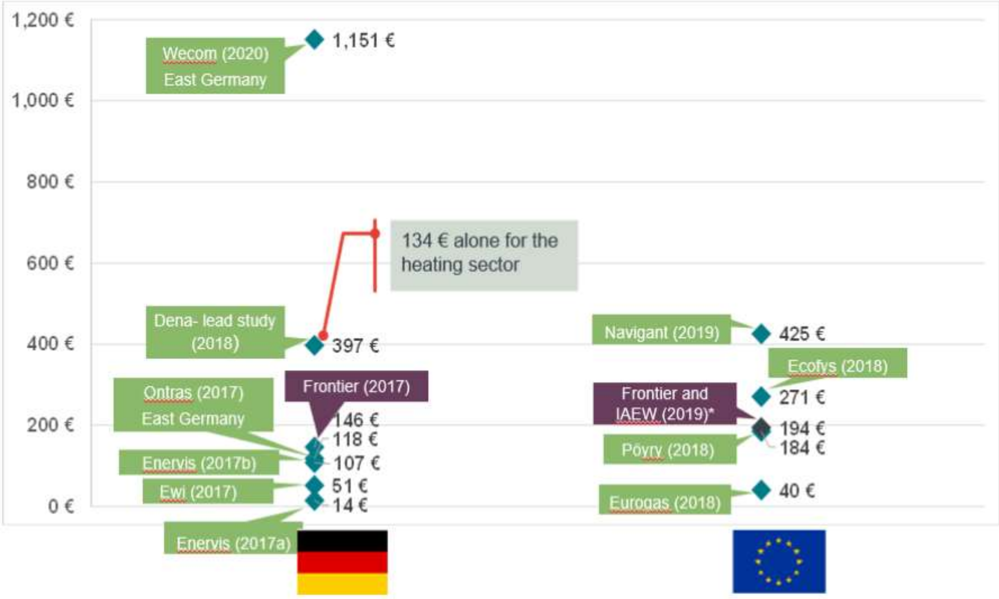
Benefits

The main benefit from a clearer framework for gas quality management at DSO level stems from reduced barriers to injections of alternative gases:

- In some cases, overall gas demand may be left unchanged, but if distributed production potential of alternative gases is sufficiently cheap, the costs of meeting this gas demand (combined gas production and transmission/distribution costs) may be reduced by opening up the possibility to inject at distribution level.
- Alternatively, depending on the cost of distribution-connected gas production (expected to mainly be renewable), increased possibilities for injection could even lead to an increase in overall gas demand, substituting for other (more expensive) energy carriers.

There are no studies that have specifically considered the benefits associated with enabling the injection of renewable and low-carbon gases at distribution level. However, several recent studies have analysed the impacts on energy system-wide costs of ensuring that renewable and low-carbon gases (and the gas system as a whole) play a role in the future energy system (see Figure 3).

Figure 3 Annual cost saving per capita and year: total energy system "with gas infrastructure" vs. "full electrification"



Source: Frontier Economics based on several studies[13]

Note: Note (1): For Frontier and IAEW (2019) the average of the two scenarios is illustrated; Note (2): Definition of the heating market varies between studies (e.g., >100 TWh/a demand in the heating market in DE assumed in the dena lead study (2018), ewi (2017), enervis (2017b), Frontier (2017) in other studies information is partly not available)

The cost savings estimated in the studies shown above are typically driven by some combination of the following:

- Avoided costs of electricity grid extension (as existing gas grids and storage can be used instead);
- Lower investment costs associated with deploying electric appliances; and
- Reduced need for power generation and storage capacity.

Distributional impacts

We consider the distributional impacts within the gas sector only:

- The net effect on **gas consumers** is ambiguous.
  - On the one hand, consumers will bear the costs associated with gas quality management (passed through tariffs). While the underlying costs of managing gas quality include both one-off and ongoing expenses, it is likely

[13] Wecom, ‚Commit to Connect 2050', April 2020; Dena, 'Leitstudie integrierte Energiewende' [Lead study on the integrated energy transition], July 2018; Ontras, 'PtG- Potenziale im ONTRAS- Netzgebiet'[PtG-potentials in ONTRAS grid system],2017; Enervis, ‚Klimaschutz durch Sektorenkopplung: Option, Szenarien, Kosten'[Climate protection through sector coupling: option, scenarios, costs], March 2017; EWI,'Energiemarkt 2030 und 2050 – Der Beitrag von Gas- und Wärmeinfrastruktur zu einer effizienten Co2 – Minderung' [Energy market 2030 and 2050 - the contribution of gas and heat infrastructure to efficient Co2 mitigation], November 2017; Enervis, 'Erneuerbare Gase – ein Systemupdate der Energiewende'[Renewable gases - a system update of the energy transition], December 2017; Navigant, ‚The optimal role for gas in a net-zero emissions energy system', March 2019; Ecofys, 'Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way', February 2018; Frontier Economics, 'Value of gas infrastructure in a climate neutral Europe', April 2019; Pöyry, 'Fully decarbonising Europe's energy system by 2050', 2018; Eurogas, 'Eurogas scenario study with PRIMES', May 2018

that, if passed through in tariffs, one-off expenses will be 'annuitised' i.e. the cost to consumers will be spread across time.

  - On the other hand, sensitive users may benefit from lower costs of adapting to gas quality. And any lower (combined) energy system costs from facilitating the injection of renewable gases will (assuming competitive retail markets) lead to lower retail bills overall (gas consumption, and therefore gas bills, may increase, but this should be offset by a reduction in the costs of consuming alternative forms of energy).

- Alternative **gas producers** may benefit on the whole, to the extent that there is greater deployment of alternative gases. This assumes profit margins are unchanged, but there is reason to believe this should be the case. Alternative gas production is typically supported financially, and support levels would normally adjust to changes in costs (either if support levels are set administratively or if competitively through a tender process).
- The net distributional effect **across DSOs/TSOs** should be (broadly) neutral, because (depending on the regulatory regime), any additional (efficiently incurred) costs are typically compensated for through additional allowed revenues.

Summary

Figure 4 Summary policy assessment, gas quality management

Criteria	Option 0	Option 1
Economic, social and environmental impacts	0	+ Costs of managing and monitoring gas quality (including associated regulatory costs). Cost savings related to reduced barriers to deploying alternative gases at distribution level. Overall impacts are uncertain in magnitude, but should be a net benefit, provided that gas quality management responsibilities are only enforced where alternative gases are deployed.
Distributional impacts: consumers	0	+/- Ambiguous effects – possible benefit for consumers from reduced energy system costs and for sensitive end-users from reduced costs of adapting to gas quality. However, consumers will also bear higher costs associated with gas quality management.
Distributional impacts: producers	0	+ Renewable gas producers: Profit margins similar, but potential for higher levels of deployment.
Distributional impacts: DSOs/TSOs	0	0 For the most part, any additional costs are (subject to regulatory approval) assumed to be compensated for by greater revenues.

Source: Frontier Economics

TOPIC II: ENERGY COMMUNITIES IN THE GAS SECTOR

Background

Decentral renewable gas potential (mainly in the form of biomethane) is spread geographically

The current European gas system has been configured based on the assumption that gas is primarily sourced from imports (both LNG and pipeline gas) as well as some indigenous production. The resulting flows are mainly from transmission through to distribution grids, and ultimately through to end-users.

The situation has started to change and is likely to develop further. In the long-term, the use of gases within Europe will need to be largely decarbonised. The domestic production potential of gases from renewable and low-carbon sources (such as hydrogen generated from solar, wind or biomass or biogas and biomethane generated from biomass) is geographically distributed (see B.2). Some of this distributed potential is anticipated to support low carbon gas production potential. For example, in Germany the current biomethane production of ca 10 TWh per year is conservatively estimated to increase to 100 TWh per year in the coming decades[14].

Barriers and possible solutions for decentral low-carbon gas deployment

To ensure all cost-effective options can be exploited in energy transition, barriers to distributed production of renewable and low-carbon gases should be removed, to ensure a level playing field with other sources of renewable and low-carbon gases. Relevant barriers include:

- lack of public acceptability,

which may be ultimately driven by

- informational barriers, or/and
- behavioural barriers.

We discuss the logic and form of the barriers as well as potential solutions in turn below.

Barriers

One of the sometimes *perceived* barriers for renewable energy deployment at local level is lack of **public acceptability** , which may complicate project development (for example, by making it more difficult for developers to secure planning permission). Possible drivers of local resistance could include:[15]

[14] Source: DVGW, 'Ermittlung des Gesamtpotentials erneuerbarer Gase zur Einspeisung ins deutsche Erdgasnetz (Gesamtpotenzial EE-Gase)' [Determination of the total potential of renewable gases for feeding it into the German natural gas grid (total potential of RE gases)], November 2019; Dena, 'biogaspartner – gemeinsam einspeisen' [biogas partners - feeding in together], January 2019; BDEW, 'roadmap gas', June 2020

[15] We note that some of these issues may be perceived by the public rather than being a factual concern. Even if they are only perceived as an issue by the public, they could develop into an acceptance barrier.

- Odour associated with biogas production;
- Increased vehicle traffic in the local area, linked to biogas or biomethane transport;
- Disturbed view or sounds (for example, due to wind farms generating electricity for hydrogen or the presence of a biogas processing unit)[16];
- Concerns over the impact of biogas production on local air quality and pollution;
- Safety concerns around local biogas or biomethane production; and
- impacts on property value (which in practice might be related to some of the concerns above).

The *underlying economic* barriers to the acceptability issue often include informational and behavioural barriers:

- **Incomplete information**: Citizens' investment, consumption and production preferences and decisions are based on costs, revenues and softer factors such as safety standards and sustainability characteristics.[17] In order for citizens to form preferences and take actions in an informed way, the respective information needs to be accessible for them. For instance, citizens may not possess the same level of information about,
  - on the one hand, disadvantages (such as being affected by the smell of a neighbouring biogas plant) and costs (such as investing in a renewable gas production plant themselves), and,
  - on the other hand, advantages (such as higher share of renewable gas consumption) and revenues (such as profit from providing the system with renewable energy).

  Therefore, they may be uncertain about the motivation and capabilities of other market stakeholders and of their own desires and beliefs, possibly leading to lack of acceptability regarding the deployment of renewable and low-carbon gases.
- **Behavioural barriers** leading to **biased perception** of information: Even when all information is available to citizens and if that information shows that it is economically beneficial to deploy renewable gas, there may be the need to actively point citizens to that information as they will not necessarily look themselves for it and as several behavioural barriers may lead to biased perception. For example, citizens may have a(n):
  - **status quo bias** and therefore abstain from switching to new gases or from engaging in new activities such gas production or from applying new production technologies;
  - **attention & salience bias** and therefore tend to focus on some aspects, while ignoring others. For instance, citizens may weigh disadvantages of smell or safety concerns more than advantages such as using a higher

16 For example, Weinand et al. (2021) find in 'The impact of public acceptance on cost efficiency and environmental sustainability in decentralized energy systems' that "in municipalities with high scenicness, it is likely that onshore wind will be rejected, leading to higher levelized costs of energy by up to about 7 €-cent/kWh."

17 See also Frontier et al's report, 'Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU - Final report', 2019

share of decarbonised energy (even if both disadvantages and advantages are known and if, rationally, the advantages would outweigh the disadvantages); one illustrative example is the **base rate fallacy** which is the tendency to assign greater value to specific, individually perceived/experienced information than to objective, statistical "base rate" information;

- **anchoring bias** and therefore rely too heavily on the first information perceived on a topic which may prevent objective judgement and updates of preferences, decisions and planned behaviours; or
- **confirmation bias** and therefore focus on evidence that fits with existing beliefs, therefore increasing the attention and anchoring bias.

Solutions

A solution to overcome the *underlying* informational and behavioural failures is to provide more accurate and unbiased information and help to avoid distorted perceptions. In particular, solutions include:

- **More complete information** can be provided in many different ways, for example by public authorities, incumbent gas players or new players (including citizen engagement).
- **Addressing biased perception of information** could involve explicitly pointing citizens to the complete set of information and stressing those pieces of information that are likely perceived less. Here, citizen engagement in a public project can be a way of building trust in the community and overcoming information asymmetries – the reason being that participants receive/are faced with a relatively complete set of information on costs, profits and softer factors such as safety concerns and impact on sustainability.

This in turn may help **overcome acceptability** issues. There is some evidence to suggest that community planning and citizen investment in renewable gas projects can improve information, help avoid distorted perceptions arising, and foster public buy in for local energy projects thereby reducing local resistance to such projects and, in turn, barriers to project development:

- One study carried out by GRDF[18], the French gas distributor, surveyed citizens and local authorities in 10 areas where a biomethane production site had already been built. This study found that around 10% of those surveyed opposed the project. The same study also concluded citizen involvement and education played an important role in addressing citizen concerns. For example, citizens who opposed the project often cited not having been informed as one of their primary grievances in regard to the project.
- Legembiente, an Italian energy consumer energy group, also found that when assisting developers with biogas and biomethane projects, fears involving smells and local air quality were more pronounced for biogas than biomethane production[19]. This local feedback led project developers to prioritise the development of biomethane projects. This example shows that investors adhering to locally expressed preferences helped to establish projects in the

[18] GRDF, Méthanisation Agricole Retour d'expérience sur l'appropriation locale des sites en injection, 2016

[19] https://www.biogaschannel.com/en/video/biomethane/7/acceptance-biogas-how-biomethane/1378/

first place – however, it does not say whether biomethane production is the more cost-effective solution relative to biogas production.

- On a national scale, in Denmark, increasing public resistance toward wind power projects was addressed by a 2009 government ordonnance allocating a minimum of 20% ownership for all new wind turbine projects to citizens living within a 4.5km radius from the turbines.[20]

Energy communities could be one potential part of the solution set

Citizens forming **energy communities** could be one specific - among several other[23] - options to overcome these failures because they are one way to allow citizens to participate in project development, thereby allowing them a more direct stake in the project and facilitating the relevant information flow.

Whether energy communities are a suitable option for overcoming these barriers depends on their cost-effectiveness relative to alternatives such as central gas deployment or decentral gas deployment by other market players.

ENERGY COMMUNITIES

While there is no single definition of what constitutes an energy community, they are typically understood to be energy utilities with a focus on citizens' participation and engagement (e.g. citizens (co-)owning renewable energy production facilities). Their primary goal is pursuing alternative objectives, such as social or environmental benefits, rather than gaining a financial profit.[21] Further, the European Commission has introduced the legal concepts of 'renewable energy communities' and 'citizen energy communities', where it defines the concept as effectively controlled by small actors (small businesses, local authorities and/or citizens) that have as primary goal to deliver social, economic and environmental benefits rather than profit-making.[22]

- There is some evidence that energy communities could foster citizens engagement which in turn could help to overcome informational, behavioural and acceptability barriers,
  - For example, in their report for the Joint Research Centre (JRC), Caramizaru and Uihlein (2020) forecast that, by 2050, 45% of renewable

[20] Bauwens, T.; Gotchev, B.; Holstenkamp, L. 'What drives the development of community energy in Europe? The case of wind power cooperatives'. Energy Res. Soc. Sci. 2016

[21] For an alternative definition the European commission describes energy communities to "organise collective and citizen-driven energy actions that will help pave the way for a clean energy transition, while moving citizens to the fore", https://ec.europa.eu/energy/topics/markets-and-consumers/energy-communities_en

[22] Article 2, Renewable Energy Directive 2018/2001/EU: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC

[23] One alternative option could be, for example, to require/allow DSOs to raise awareness among local farmers or other potential renewable gas producers regarding the possibilities of decentral gas production and injection and to help them coordinate and to aggregate resources/maximise utilisation of facilities in order to profit from some degree of economies of scale. This is done for example in Ireland, where the DSO works to educate farmers to a) increasingly grow sustainable crop because these can be used to b) produce renewable biogases, c) to coordinate production, compression and injection with other farmers to d) gain revenue from injecting it into the grid. In Ireland this is currently tried out for one trial injection point, and if successful, this model will be rolled out more widely.(Source: Stakeholder interview with Cormac Walsh from Energy Co-operatives Ireland, 17th of June 2021)

energy production could come from citizens and 37% of that production could come through from collective projects, such as energy communities.[24]

  - Also energy communities have been recognised as playing a special role in the EU electricity market framework (see Electricity Directive) and the Renewable Energy Directive 2018/2001/EU.

- At the same time energy communities may also involve some inefficiencies. Issues mentioned in stakeholder interviews include more time-consuming coordination among energy communities' participants because of
  - their relative lack in know-how, experience, and professionals;[25]
  - the effort needed to deal with scepticism of some members,[26]
  - the potential lack or varying degree of citizen engagement,[27] and
  - the larger number of people 'around the table' complicating for example the agreement on task responsibilities and – importantly – financial responsibilities.

The respective relative advantage or disadvantage of energy communities depends on the specific market and cultural context and the respective regulatory and market framework needs to make sure that energy communities can be established when this is cost-effective from a market perspective.

Status quo and problem definition:

EU legal framework for energy communities: There are some regulatory gaps in the gas sector (Renewable Energy Communities but no Citizen Energy Communities)

Currently energy communities are more common (in some Member States) in the electricity sector (also see following section). In contrast, the gas sector lacks that experience and history of energy communities.

While it is uncertain whether or not there will be a role for energy communities in the gas sector in the future, the market framework should in principle enable the establishment of energy communities, whenever it is a cost-effective option to facilitate the deployment of renewable gas potential. Ensuring cost-effectiveness requires avoiding discrimination of energy communities as well as other market players. This, depending on the context, may mean that energy communities are granted

[24] One reason for this could for instance that they might help to foster engagement and interaction with many different local players (intermediaries/aggregators can play an important role) and thereby enable profiting from economies of scale: Renewable gas production involves high fixed costs and therefore production facilities (e.g. anaerobic digestor or electrolyser) gain from larger utilisation and economies of scale. This also applies for injection into the grid, which requires the deployment of a compressor that compresses the gas to a level that exceeds the gas compression level of the grid. The compression costs (and injection costs more generally) could be reduced if the utilisation of the compressor could be maximised by coordinating and aggregating decentrally produced gases from several producers.

[25] This may hamper access to banking funds as well as equity, albeit energy communities may help to mobilise private capital investments as citizens are the owner of these projects and might, therefore, be more likely to invest in them. Source: Stakeholder interview with GRDF, 29th of June 2021

[26] Source: Stakeholder interview with GRDF, 29th of June 2021

[27] Source: Stakeholder interview with GRDF, 29th of June 2021

- more rights, when *negative* discrimination against them is removed; or it may mean
- less rights, when *positive* discrimination is removed.

Only then, namely in a non-discriminatory market, can market players compete fairly and renewable gases be deployed most cost-effectively.

Currently there are some perceived gaps in the EU legal framework for energy communities in gas: The EU legal context introduces definitions of energy communities and aims at providing energy communities specific rights (level-playing field engagement and additional rights) across Member States. However, while the RED II defines Renewable Energy Communities (RECs)[28] as a concept that applies to energy communities engaged with renewable energies including gas, there is no such concept as the Electricity Directive's Citizen Energy Communities (CECs)[29] for the gas sector. Differences across RECs and CECs include the following (for more details, see Annex B.1):

- Both RECs and CECs are granted rights to participate in the energy market on a level playing field with other players and Member States are to ensure explicitly that there is no negative discrimination against CECs and RECs. [30] RECs have additional privileges (such as the requirement that Member States consider specificities of RECs when designing support schemes). [31]
- Accordingly, the qualifying criteria for RECs are more restrictive than for CECs. For example, RECs must only involve renewable energy (while CECs in electricity can involve non-renewable forms of energy) and they must be located in proximity to production facilities (which is not the case for CECs).

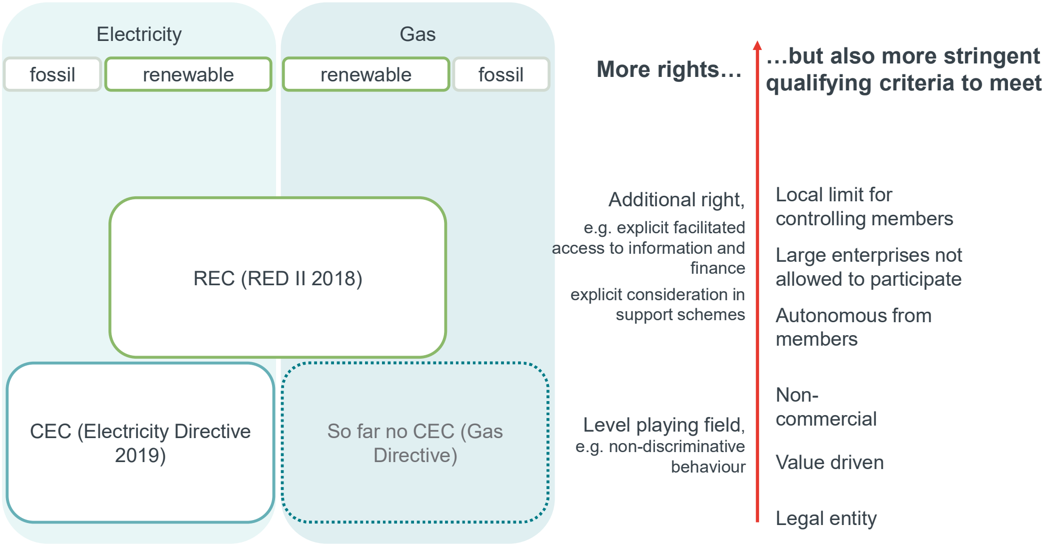
28 Recast Renewable Energy Directive 2018/2001/EU (RED II) (2018)

29 Directive 2019/944/EU, "Electricity Directive" (2019)

30 For instance, the **Electricity Directive** (Art 22, 1, 3, 4a,b,d,e,I and Recital (71)) arranges for CECs to have "an enabling framework, fair treatment, a level playing field and a well-defined catalogue of rights and obligations" and to be "treated in a non-discriminatory and proportionate manner with regard to their activities, rights aggregation" and "subject to non-discriminatory, fair, proportionate and transparent procedures and charges". **RED II**, for instance, orders for RECs that "unjustified regulatory and administrative barriers to renewable energy communities are removed" and that they are "are not subject to discriminatory treatment".

31 "Member States shall take into account specificities of renewable energy communities when designing support schemes" (RED II, Recital (26) and Art 22, 7).

Figure 5 Mapping of EU level frameworks for energy communities



Source: *Frontier based on RED II and Electricity Directive*

Note: *Rights and criteria non-exhaustive*

The gap in the EU legal framework might mean less systematic rights for energy communities across Member States

The gap in the EU legal framework might mean less systematic rights for energy communities

- within an energy sector (gas or electricity) across Member States, and/or
- across energy sectors (gas and electricity).

Less systematic rights within a sector across Member States

Experience from the electricity sector suggests that, before EU level intervention via the RED II and Electricity Directive, Member States had implemented varying national legislations regarding the rights for energy communities. This was one of the drivers – along with cultural differences – for a heterogeneous picture of energy communities across European countries.

- For example, the high number of energy communities in Germany, Denmark and the Netherlands stems from a long tradition of citizen participation and ownership:
  - In Germany, energy communities had formed since the early 1970s and the legal concept had been developed for the electricity sector via the German Renewable Energy Act (EEG) since 2017.[32]
  - Similarly, Denmark has a long tradition of energy cooperatives and in 1999 the Electricity Reform–Agreement stated that elected consumer representatives must have a controlling influence in network operating companies. Further support for consumer ownership of wind farms to

[32] Tounquet, F., L. De Vos, I. Abada, I. Kielichowska, and C. Lessmann, 'Energy Communities in the European Union', No. May, 2019 *(cited by Hannoset et al. 'Energy Communities in the EU Task Force Energy Communities', 2019)*

generate electricity was established via the new Act on Renewable Energy in the energy policy agreement 2008-2012, amended to apply to solar plants later as well.[33]

- In the Netherlands, energy community history started in the 1980s/1990s and the legal framework has been implemented in the electricity sector via the Dutch Electricity Act 1998.[34]

- In contrast, some countries such as, for example, Greece and Luxembourg, have not had much experience with energy communities until recently.

Figure 6 Energy communities (mostly engaged in electricity) in 2016 are concentrated in a small number of countries

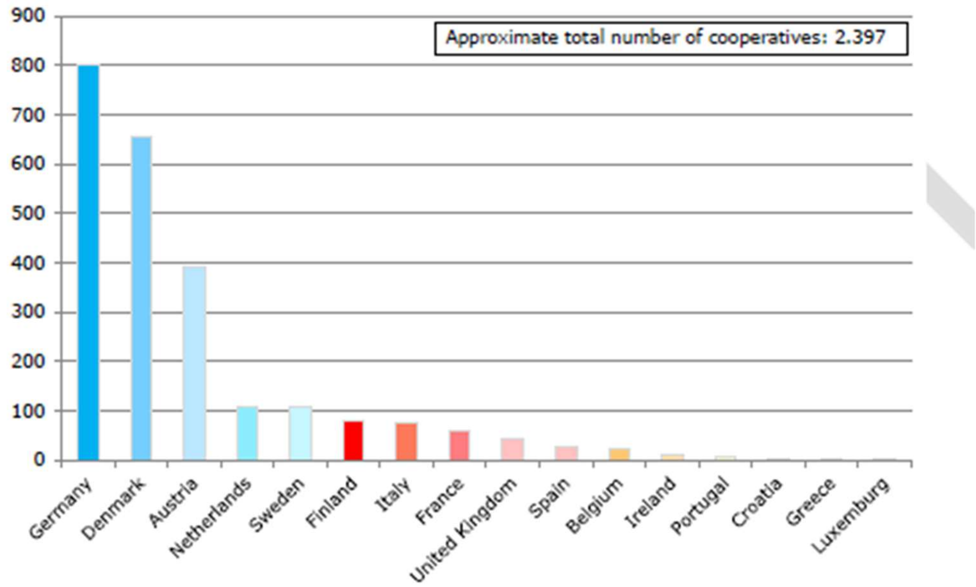


Figure 33 Approximate number of renewable energy cooperatives in seventeen European countries

Source: Based on figures by (RESCoop 2016), own illustration

Source: *Impact Assessment RED II, study on the impact assessment for a new Directive mainstreaming deployment of renewable energy and ensuring that the EU meets its 2030 renewable energy target, Final task 1 & 2 report: "Mainstreaming RES" ENER/C1/2014-668, November 2016*

Note: *Most of these energy communities are active in the electricity sector, few in the gas or heating sector.*

Introducing the concept of energy communities in the EU legal context could have a decreasing or increasing effect on the number of energy communities, depending on how the EU level rights and obligations compare to the existing national ones. However, overall there is an expectation that currently more Member States are negatively discriminating energy communities than positively discriminating and supporting them. Therefore, the EU level reforms, introducing the concept of energy communities in the legal context would be expected to show a positive effect on the number of energy communities. In fact, EU level reforms (RED II and

[33] Ronne, A., and F.G. Nielsen, 'Consumer (Co-)Ownership in Denmark', Energy Transition - Financing Consumer Co-Ownership in Renewables, Palgrave Macmillan, Cham, 2019.

[34] Information of historic numbers of energy communities retrieved from https://www.hieropgewekt.nl/lokale-energie-monitor on June 18th 2021; Tounquet, F., L. De Vos, I. Abada, I. Kielichowska, and C. Lessmann, 'Energy Communities in the European Union', No. May, 2019. *(cited by Hannoset et al. 'Energy Communities in the EU Task Force Energy Communities', 2019)*

the Electricity Directive) have coincided with an increase in energy communities, although it is difficult to separate cause and effect:

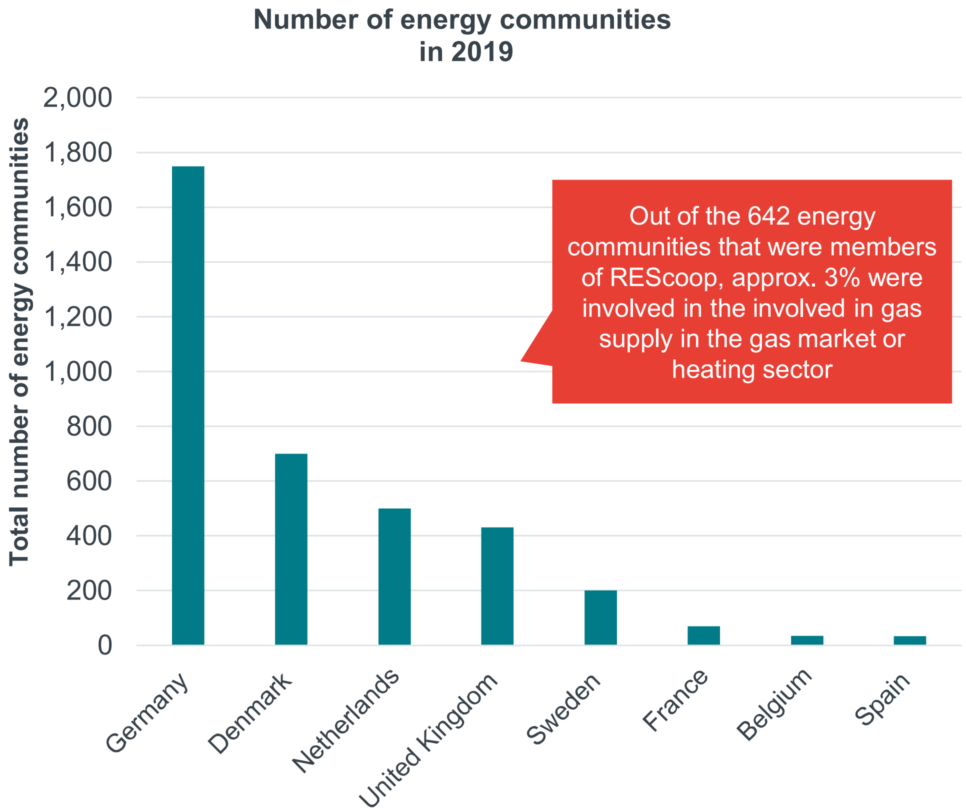
- In 2019 there were 3,718 energy communities in the European countries assessed in Figure 7.[35] Although Figure 6 and Figure 7 do not rely on the same underlying database and therefore it is not clear whether the same definition of energy communities was applied in both, the data suggests that there was some increase in the number of energy communities between 2016 and 2019.[36] While it is not clear to what extent defining the concepts of RECs (in 2018) and CECs (in 2019), and subsequently implementing them at national level, caused the increase in energy communities, it could potentially be one of the drivers for it. [37]
- There are still significant differences between the development of energy communities across the EU: Overall, 91% of energy communities in the EU are located in only 4 out of the 8 assessed countries. We note that another reason for the remaining differences in the number of energy communities between countries could also be that it takes time for energy communities to establish following legal reforms - for example, Portugal introduced the concept of RECs (for the electricity sector only though) as a reaction to RED II with a Decree that entered in force at the beginning of 2020.

35 Unfortunately, data is not available for all countries that were assessed in Figure 7.

36 We note that an increase in the number of energy communities does not translate in an increase of renewable energy, as it could be that energy communities have merged or split and generally of different sizes (in terms of energy or capacity).

37 One other reason could be technological development making decentral projects more feasible and therefore giving decentral entities more opportunities to be established.

Figure 7 Energy communities in 2019 have increased in number relative to 2016, but are still unequally spread across countries and mainly concerned with electricity



Source: ***Bar chart****: European Commission, JRC report 'Energy communities: an overview of energy and social innovation' based on various sources, 2020;* ***text box:*** *REScoop, https://www.rescoop.eu/network, 2021*

Note: *The energy community number estimates for 2016 and 2019 are based on different sources, as it was not possible to retrieve the 2016 data for a more updated year.*

We note however that – in contrast to the electricity sector - the magnitude of the differences between the development of energy communities across the EU may be less significant, as most energy communities are active in the electricity sector, only few in the gas sector: Out of the energy communities that were active members of the European federation of citizen energy cooperatives REScoop in 2021, only an estimated 3% were involved in gas supply in the gas market or heating sector.[38]

Less systematic rights across gas and electricity sectors

A dedicated CEC concept for the gas market could also facilitate sector-coupling between the electricity and gas sectors: As noted above, the criteria that need to be met in order to qualify as REC are relatively restrictive and apply for energy communities concerned with renewable energies of all forms including gas. However, while in the electricity sector there is a framework with less restrictive qualifying criteria (CEC), there is no such framework for the energy communities

[38] In the absence of publicly available data on the number of energy communities in the gas sector, we have used those energy communities that are members of the REScoop network and thereof calculated the share of energy communities in the gas and heat market (18 out of 641).

concerned with gas. The lack of a CEC principle as a fallback option for those energy communities in the gas market that do not quite qualify as RECs creates the risk that these energy communities are not able to participate on a level playing field in the gas market. Also, CECs in the electricity sector which may want to expand activities to the gas sector and engage in dual supply in a sector-coupled market, i.e. supplying electricity and gas in parallel, may risk not qualifying as any energy community concept.

For example, communities would not be recognised as REC in the gas sector when a majority of members (e.g. consumers) is not located in proximity of the renewable project, when members include larger businesses or when for any member the participation constitutes their primary commercial or professional activity. This could hamper investment in and the utilisation of plants, and therefore impede the scale-up of energy community projects.

Filling the gap

We assess options of frameworks that fill the current gap in EU legislation for energy communities in gas. The objective is to assess from an economic perspective the degree to which the framework enables[39] the establishment of energy communities (in the event that there is a case for energy communities on the respective markets) in a cost-effective way from a system perspective.

Important indicators of such a cost-effective framework are

- **no negative discrimination against energy communities**: Energy communities – as well as all other market participants – need to be able to participate on the market without being discriminated against. Discrimination does not only include conscious or intentional discrimination. It also includes unintentional discrimination such as administrative burdens that are a market entry barrier for some players (e.g. smaller players such as energy communities) but not to other players; and
- **no market distortions to the wider system**: at the same time the framework should ensure that rights are granted in a way that are cost-effective from a system perspective. For example,
  - removing administrative burdens for all market players does not distort the market by distorting competition – rather it will increase market entry and therefore increase competition.
  - on the contrary, any player-specific rights are a positive discrimination which bears the risk for (unintentional) adverse effects on the wider system, namely on players not covered by the positive discrimination. It therefore needs to be assessed how and to what degree specific rights affect the wider system and whether, overall, the net effect is beneficial or not.

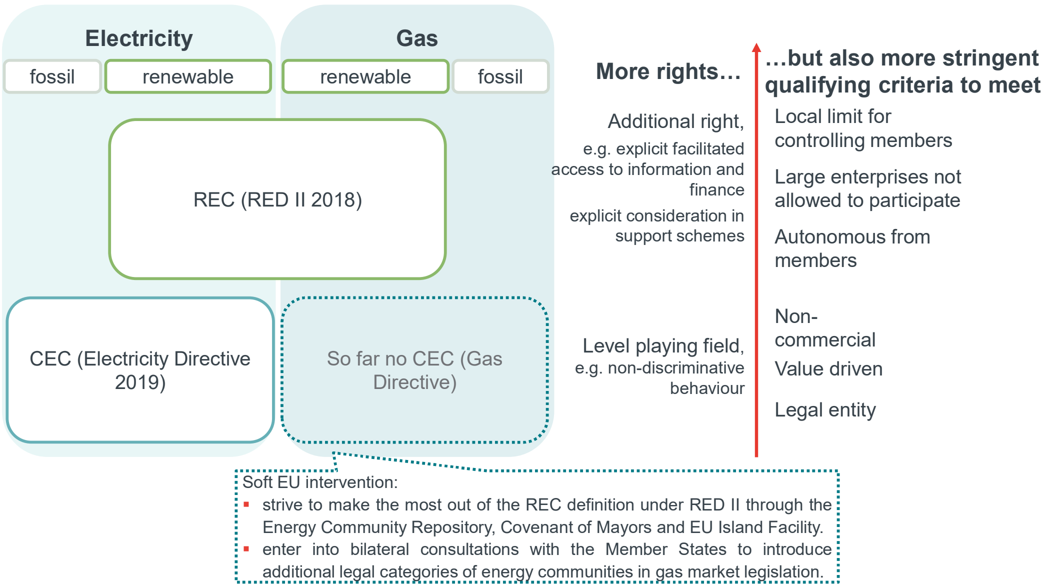
Against this background we assess the policy options defined by the European Commission.

[39] Thereby it is important to note that i) the current gap may or may not have an impact in the future, ii) the framework filling the gap may or may not be used in the future. Assessing i) and ii) is beyond the point of this assessment and remains to be seen in the future years.

Policy options

Option 0 – non-regulatory Option, counterfactual: The European Commission suggests for the counterfactual that DSOs are obliged to enable reverse flows from distribution to transmission level. Regarding energy communities, under this option, the current Renewable Energy Community (REC) concept as defined under RED II remains the only concept for energy communities at EU level. This means that Member States are – at EU level legislation – only obliged to provide energy communities with a level playing field and additional rights if these meet all requirements of a REC. If they do not fulfil all requirements, there is no alternative framework that ensures minimum rights for energy communities at EU level. We also note that even without EU level legislative changes, the European Commission intends to enter into bilateral consultations with Member States to discuss whether it is necessary/beneficial to amend and introduce additional legal frameworks for energy communities in their gas market legislations at national level.

Figure 8 Option 0 - non-regulatory option, counterfactual

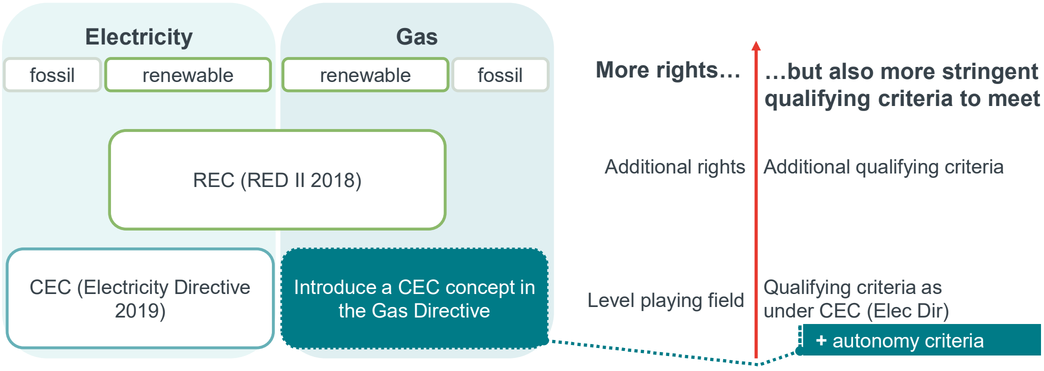


Source: Frontier Economic based on RED II, Electricity Directive and DG Ener

- **Option 1 – introducing a CEC concept in the Gas Directive in order to provide level-playing field rights and facilitate decarbonisation**: As in Option 0, DSOs are obliged to enable reverse flows from distribution to transmission level. Regarding energy communities, Option 1 would go further than the existing Renewable Energy Community (REC) concept as defined by the RED II by introducing a general Citizen Energy Community (CEC) concept in the gas sector. The CEC concept lays down less restrictive requirements, e.g. regarding the geographical scope, the size of enterprises allowed to participate, the proximity requirements for being allowed to take effective control and the types of gases this relates to. It would, however, introduce the governance principle of autonomy even though this is not required for CECs in under the Electricity Directive. It would aim to provide level-playing rights also to those ECs that meet the requirements for a CEC even if not for a REC. (If, however, the more restrictive requirements of the REC would be met, the energy community would be defined as such and consequently face all additional rights.)

- **Option 1a – as Option 1 above , but with an additional right for CECs to an exemption from the proposed obligation on DSOs and TSOs to enable 'reverse' flows from distribution to transmission level.** The exemption could be requested by the CEC or by the DSO responsible for the grid to which the CEC is connected.[40] The right to an exemption from the reverse flow obligation would only apply to CECs whose gas production (and supply) within the DSO grid exceeds a pre-determined share of total gas consumption on the DSO grid in question.

Figure 9 Option 1

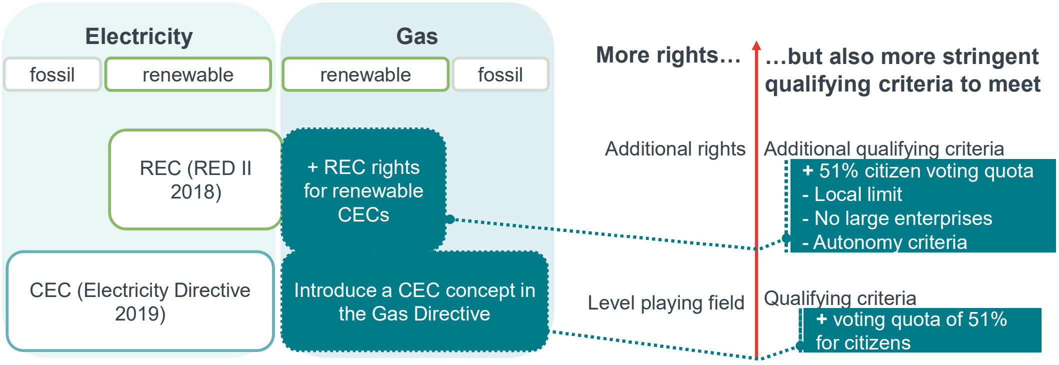


Source: Frontier Economic based on RED II, Electricity Directive and DG Ener

- **Option 2 – as Option 1 plus increased citizen focus and easier obtainable additional rights when engaging in renewable gas**: Option 2 involves Option 1 and additionally
  - stresses and strengthens the **citizen character** of energy communities by ensuring that the operational control remains in the hands of citizens rather than enterprises, e.g. by requiring voting quotas for citizens of 51%;
  - provides the **additional rights provided to a REC** also to any energy community that qualifies as CEC and involves only **renewable gases**. This means that an energy community whose participants in control are geographically widely spread and which applies renewable gas, which under Option 1 would not have been provided any additional rights, will now have the additional right of RECs (facilitated access to finance and information, regulatory and capacity-building support in enabling RECs, consideration of the specificities of RECs when designing support schemes).

[40] In the former case, the CEC would have a right to the DSO's co-operation on the matter (if the DSO is a different legal entity to the CEC). In the latter case, we assume the DSO would need to seek the CEC's approval for doing so.

Figure 10 Option 2



Source: *Frontier Economic based on RED II, Electricity Directive and DG Ener*

Cost benefit analysis

Below we:

- discuss the categories of cost and benefit associated with facilitating energy communities that are not covered by current EU legislation at a general level (see section "Generic assessment") before we
- assess the individual options (see section "Assessment of each policy option").

Generic assessment

Costs

Impact on competition

There is a risk that introducing energy communities via positive discrimination, i.e. via granting specific rights for energy communities that do not apply for competitors, may have a negative impact on competition in the wholesale market for gas, to the extent that the support that energy communities receive helps to reduce their costs compared to otherwise efficient commercial actors. After all, any positive discrimination bears the risk of (unintentional) adverse effects on the wider system raising overall costs.

However, this risk will be smaller if the market framework for energy communities ensures that:

- energy communities target additional potential that would have been challenging for commercial actors to develop (for instance, due to local opposition); and
- the support received by energy communities is principally one-off and related to information and technical assistance and overcomes a market failure in the area, as opposed to direct financial support or indirect support, for example in the form of:
  - different risk allocation compared to commercial actors;[41] or

[41] Examples of the latter include allowing energy communities to submit a connection application at a later point in time than usual or exempting them from the requirement to submit the planning permission when applying for a connection.

- different rules regarding unbundling of distribution operators (for example, less stringent provisions regarding non-discrimination between energy community sources of production and other sources of production connected to the DSO grid).

Benefits

The main potential benefit from a clearer framework for energy communities stems from more initiative and management drive to make the energy transition work:

- If energy communities help with overcoming acceptance issues cost-effectively relative to other market players and even may help to mobilise citizens' own private capital[42], it is likely that there will be lower costs incurred for renewable gas production and deployment because all supply options are available including the renewable decentral gas projects that would - absent increased acceptance - not be available or at higher costs.
- Alternatively, depending on the cost of distribution-connected gas production, increased possibilities for injection could even lead to an increase in overall renewable and low-carbon gas supply and demand, substituting for other (more expensive) energy carriers.

Whilst there is potential for community ownership of gas projects to lead to the benefits outlined above, including overcoming the barriers related to public engagement, there is limited empirical evidence regarding the probability these benefits might be realised and on the magnitude of the impact. Overall, the probability that these benefits might be realised and the magnitude of the impact will likely depend on the decentral renewable potential, the development of the wider energy system, the actual design of the regulatory framework, and acceptance problems in the absence of energy communities.

Distributional effects

In general, from an economic perspective, distributional aspects are less open to a clear assessment of what is beneficial or disadvantageous: An economic evaluation can help establish the facts. But whether certain distributional effects are seen as positive or negative is largely a political question.

The distributional effects can be summarised as follows:

- Benefit likely for any **energy communities gas producers** that would not have come forward under the counterfactual (though may also lead to a displacement in production owned by other players).
- Uncertain impact on **energy communities gas consumers**. Consumers might benefit, if energy communities can lead to energy system cost savings and prices faced by consumers reflect those cost savings (which may not always be the case).
- Neutral effect on **DSOs**: Some gas DSOs may face additional costs, for example if increased renewable gas injection (compared to the counterfactual) results in higher costs associated with operating the system (e.g. costs of

42 Source: Stakeholder interview with GRDF, 29th of June 2021

managing congestion and gas quality). However, the net distributional effect **across DSOs** should be (broadly) neutral, because (depending on the regulatory regime), any changes in (efficiently incurred) costs are typically balanced out by changes in allowed revenues.

Assessment of each policy option

While the generic costs and benefits above apply to all the options considered, the magnitude of the impacts will vary depending on the options.

Option 0 – non-regulatory option, counterfactual

Under this option, Member States have the obligation to introduce a framework only for energy communities in the gas sector that qualify as REC as defined under RED II. This means that these energy communities should face market entry and participation rights at equal footing with larger market players and even some additional rights.

In contrast, energy communities not qualifying as REC under RED II are subject to the national framework provided for them. Member States have no obligation to introduce a framework, nor to conduct a CBA whether a framework for them would be beneficial in principle, nor to even consider energy communities. There is therefore a risk that, under this option, some of the benefits (and the costs) associated with energy communities in gas (as described above) will not be realised.

Option 1 – introducing CEC concept in the Gas Directive in order to provide level-playing field rights and facilitate decarbonisation

Compared to the counterfactual, Member States are required to provide a framework that ensures a level playing field also for gas energy communities that qualify as CEC.

This could mean that a wider set of community-led energy initiatives (for example those involving non-renewable low-carbon gas and those supplying renewable gases, but with customers in a different location to the production facilities managed by the energy community) are provided with level playing field rights. It may in turn lead to an increase in such energy communities.

Costs

If Member States would not otherwise have introduced a framework similar to that for CECs at national level, there would be some additional costs, compared to the counterfactual:

- In a first step, costs of assessing whether there are barriers for the establishment and development of energy communities, considering the specific characteristics of local energy communities in terms of size, ownership structure and the number of projects they have. These include:
  - Ongoing labour costs to employ the required workforce for additional task; and

    - Other one-off transformation costs in the event of changes to team structures, etc.;
- In a second step (after barriers have been assessed), costs of addressing barriers (e.g. legislative changes to reduce administrative burdens, establishing transparent rules or secure non-discriminatory treatment). These costs may include:
    - one-off costs for changing the respective rules; and/or
    - ongoing labour and operational costs if a single point of contact is intended to guide energy communities through the administrative process, such as intended in recital 50 of the RED II.[43]
- Possible additional costs associated with setting up and running energy communities.

Benefits

This option involves a more systematic consideration (by Member States)[44] of the issues facing energy communities and the implementation of a regulatory framework for CECs[45]. This would therefore increase the probability that the generic benefits associated with treating energy communities that do not qualify as REC but as CEC fairly (described above) do materialise to the extent that:

- some Member States would not, absent EU intervention, implement a framework for CECs; and
- the implementation of a framework leads to the formation of additional gas energy communities or to the improved operation of existing gas energy communities.[46]

Option 1a - as Option 1, but with an additional right for CECs to an exemption from the proposed obligation on DSOs and TSOs to enable 'reverse' flows from distribution to transmission level

As a first step, it is important to consider the situations when such an exemption might be requested.[47]

- For a CEC involved in renewable gases (which might otherwise have met the qualifying criteria for a REC), the main but not sole benefit of CEC status is the ability to serve consumer members distant from the region in which production is taking place (while still benefitting from level playing field rights). It therefore

[43] Note that the provision of clearer guidance is part of the counterfactual in those countries that have energy communities qualifying as REC and that therefore have already incurred these costs. However, in countries that only have energy communities qualifying as CEC under Option 1, these costs are incremental to the counterfactual.

[44] See section above titled 'The gap in the EU legal framework might mean less systematic rights for energy communities across Member States'.

[45] For examples see section "Less systematic rights across gas and electricity sectors".

[46] It is important to note that the formation of energy communities can only be regarded as beneficial from an economic perspective if, as mentioned before (see section on "Costs"), the market framework ensures that the overall net effect on the wider system is not negative, as would be the case for instance if competition was distorted.

[47] The exemption could be requested by the CEC or by the DSO responsible for the grid to which the CEC is connected (see section Policy options).

seems unlikely that such CECs would avail themselves of the possibility for an exemption.

- A CEC involved in non-renewable gases might consider whether an exemption would be of benefit.

In the latter case, one needs to consider whether the CEC's payoff resulting from an exemption would be in line with those of society.

- On the one hand an exemption could lead to reductions in certain costs (to society), which might be passed on to CEC to a large degree:
  - There would be no costs associated with enabling reverse flows.
  - There may also be reduced costs associated with managing gas quality.
    - Either the required injection quality for the distribution grid in question remains unchanged. In this case, the DSO may avoid some costs associated with maintaining a gas quality that meets the requirements of the adjacent transmission system.
    - Or the required injection quality for the distribution grid might be relaxed. Lower standards might permit either reduced costs of injection or greater levels of injections.
  - These impacts will have been assessed more extensively as part of the assessment of the decision to implement the reverse flow obligation.
  - The extent to which CECs would benefit from these cost savings depends on how these costs are distributed under the counterfactual, which is uncertain.
    - First, the CEC may not account for the entire market share of the DSO in question.
    - Even where they do, while a large share of the costs may have been borne by DSOs and, in turn, producers and customers connected to the distribution grid (including energy communities), it is also possible, depending on the national framework, that some costs would have been shared with other players (e.g. with the TSO and, ultimately, customers located elsewhere in the gas system).
- On the other hand, an exemption could lead to increased costs, notably in cases where the distribution grid is at risk of saturation/congestion due to increased distributed production.
  - The loss of the ability to flow gas to transmission grids may either result in increased costs associated with ensuring flexibility at distribution level (for example, building gas storage at local level or meshing with adjacent distribution grids) or in reduced load factors for CEC production or more generally all local production due to interruption (leading to higher average costs of production). In the extreme, this could disable the development of further local projects by third parties all together, thereby crowding out additional local gas production. Such costs may in part be mitigated through commercial solutions (e.g. commercial reverse flows). These impacts will

have been assessed more extensively as part of the assessment of the decision to implement the reverse flow obligation.

- The extent to which CECs would bear these increased costs is also uncertain.
  - As above, CECs may not always account for 100% of the market share in the DSOs to which they are connected.
  - Where they do, in principle, producers (whether in receipt of financial support[48] or not) should be exposed to the costs associated with potential interruption of injection. But exactly how any wider costs of ensuring flexibility are allocated by DSOs to grid users (and between DSOs) is uncertain and will vary depending on the framework in place at Member State level.

Overall, therefore, there is some uncertainty regarding whether the payoffs to a CEC from requesting an exemption from the reverse flow obligation will be in line with societal costs and benefits.

- In some cases, an exemption request might be in line with societal interests – i.e. it would result in a positive impact on society (Note: Such a benefit would not be driven by the form of ownership per se. Rather, it would indicate that there would have been the case for the DSO in question to be exempt from the reverse flow obligation even if there was no CEC present).
- In other cases, an exemption request may be in the interests of the CEC but not in those of society as a whole – i.e. the impact on society would be negative.

We note further that, to the extent there are positive payoffs from obtaining an exemption, this option could promote energy communities. However, there are risks that existing undertakings could seek to convert themselves to energy communities, purely to circumvent the general reverse flow obligation that would apply to DSOs. This risk may be mitigated by autonomy and governance criteria in place.

Option 2 – in addition to Option 1, stresses the citizen empowerment and granting those energy communities qualifying as CEC and engaging in renewable gas additional rights

Under this option, compared to Option 1, two effects have to be considered:

- The **citizen focus** requirement may have an ambiguous impact on the formation of energy communities:
  - On the one hand, for a given set of energy communities this is an additional restriction which could mean that fewer energy communities qualify as CEC than in Option 1, and therefore are not awarded the level playing field rights described. Whether this is a restriction in practice depends on the national frameworks in place and whether these include voting quotas of 51% for citizens already. Data suggests that at national level only Germany has a

48 Under the draft CEEAG (which is subject to consultation) "…*beneficiaries of [aid measures] should be exposed to risks that they can contribute to managing, for example risks associated with the curtailment of renewable energy linked to periods of excess production or to insufficient transmission*" (paragraph 102).

voting quota in place that reserves 51% of the voting rights to citizens and therefore, the restriction of this option will be binding:

- In Germany, 51% of the voting rights in energy communities must be held by natural persons that have a permanent residency in the administrative district of the location of the project. In addition, no individual member or shareholder is allowed to hold more than 10% of the voting rights.
- In other countries, a specific percentage of the participants must be private actors: In the Netherlands, for example, 80% of the participants need to be private end-consumers;
- In most Member States, however, there is no specific threshold of citizen participation.

- On the other hand, if it leads citizens to perceive more empowerment, they may be more willing to participate in energy communities as well as to support the community with private capital. For instance, Recital 70 in RED II testifies that "*The participation of local citizens and local authorities in renewable energy projects through renewable energy communities has resulted in substantial added value in terms of local acceptance of renewable energy and access to additional private capital which results in local investment, more choice for consumers and greater participation by citizens in the energy transition. Such local involvement is all the more crucial in a context of increasing renewable energy capacity. Measures to allow renewable energy communities to compete on an equal footing with other producers also aim to increase the participation of local citizens in renewable energy projects and therefore increase acceptance of renewable energy*".

That means it is unclear whether the citizen focus may bring about more or fewer energy communities.

- Introducing **less restrictive criteria for receiving all rights of a REC**, i.e. not only a level playing field but also additional rights (*given citizen focus met)* is likely to have a positive effect on the formation of renewable gas energy communities: Relative to Option 1, more energy communities engaging in renewable gases are treated not only fairly but are granted additional rights similar to a REC, such as facilitated access to finance: namely all those energy communities that engage in renewable gases, but do not qualify as REC. This would involve
  - additional costs (including a more negative impact on competition) and additional benefits as set out above in the Generic assessment; and
  - authorities incurring costs associated with providing information (e.g. technical assistance or information regarding access to finance) to energy communities. Such costs may include:
    - one-off costs for setting up information and consulting webpages; and
    - ongoing labour and operational costs for the time spent by personnel for providing specific information for any given energy community request for information/finance etc.

Summary of assessment of policy options

Figure 11 Summary policy assessment, energy communities

Criteria	Option 0	Option 1	Option 1a	Option 2
Economic, social and environmental impacts	0	+/- Costs for establishing energy communities and establishing a level-playing field for them. Benefits in the form of potential for more volume or cost-effective deployment of decentralised renewable energy. Could increase probability that benefits materialise. Overall impacts are uncertain in magnitude and depend on the decentral renewable potential, the development of the wider energy system, and acceptance problems in the absence of energy communities.	+/- Compared to Option 1, impacts are more uncertain. Risk that energy communities may seek exemption from reverse flow obligation where this is not in society's interest.	+/- Similar to Option 1 except: Additional costs compared to Option 1 for granting additional rights such as providing facilitated access to information and finance to energy communities. Potentially more volume or lower cost renewable gas deployment. Overall impact uncertain in magnitude.
Distributional impacts: energy communities consumers	0	+/- Uncertain impact as both whether there is a system cost saving and whether this is passed on to consumers is uncertain.		
Distributional impacts: energy communities producers		+ Benefit likely for any renewable gas energy communities producer that would not have come forward under the counterfactual.	+ Similar to Option 1 (although Option 1a could lead to more energy communities coming forward compared to Option 1, this may also be at expense of other producers)	+ Similar to Option 1 (Although there may be fewer energy communities qualifying relative to Option 1, these receive additional rights if they involve renewable gas.)
Distributional impacts: DSOs	0	0 Broadly neutral impact on DSOs as described above.	0	0

Source: Frontier Economics

TOPIC III: CONSUMER'S PARTICIPATION, SMART METERING SYSTEMS

Problem definition and status quo analysis

Smart meters are electronic devices which record the energy consumption and communicate that information to the consumer in real-time. They may be combined with an in-home display. Whereas traditional meters have to be read manually, smart meters automatically record the information and enable two-way communication between the meter and the central system. With traditional meters, retailers will only have information on quarterly or annual consumption, which means that they have to estimate the consumption profile of their customers. Many consumers (typically households and smaller businesses) are only equipped with traditional meters, and therefore cannot be exposed to daily fluctuations in gas prices.

In the gas market, the requirements from EU legislation still lie in the Gas Directive 2009/73/EC (the Gas Directive) which states that Member States shall ensure the implementation of intelligent metering systems which may be subject to a CBA to be conducted by September 2012.[49] The Gas Directive did not set deployment targets for Member States.[50]

As of 2019 only five Member States[51], the Flanders region of Belgium[52], and the United Kingdom had proceeded with a large-scale roll-out of gas smart meters. All seven rollouts are still on-going and are due to end before 2025. An estimated 16 million gas smart meters had been rolled out by the end of 2018 as compared to 99 million electric smart meters.[53] As of 2018, 18 Member States had conducted a total of 25 CBAs[54] out of which 14 were positive, 6 were negative and 5 were inconclusive. For these, the benefit incurred from a potential smart meter roll-out was estimated to be 24% higher than the estimated costs, on average[55].

Five Member States (Austria, Latvia, Slovenia, Slovakia, and Romania) produced a positive smart meter cost-benefit analysis but have not yet announced any plans for widescale roll-out.[56]. Finally, 7 Member States with an active natural gas market

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49 Directive 2009/72/EC, Annex I

50 This requirement has since been updated for the electricity sector. Directive (EU) 2019/944 requires Member States to ensure the deployment of smart metering systems subject to a cost benefit assessment. Should the CBA be positive, a target of 80% of final consumers must be equipped with smart meters within seven years of the CBA.

51 France, Ireland, Italy, Luxembourg, the Netherlands.

52 https://www.febeg.be/fr/domein/compteurs-intelligents-smart-meters

53 European Commission, Benchmarking smart metering deployment in the EU-28, December 2019

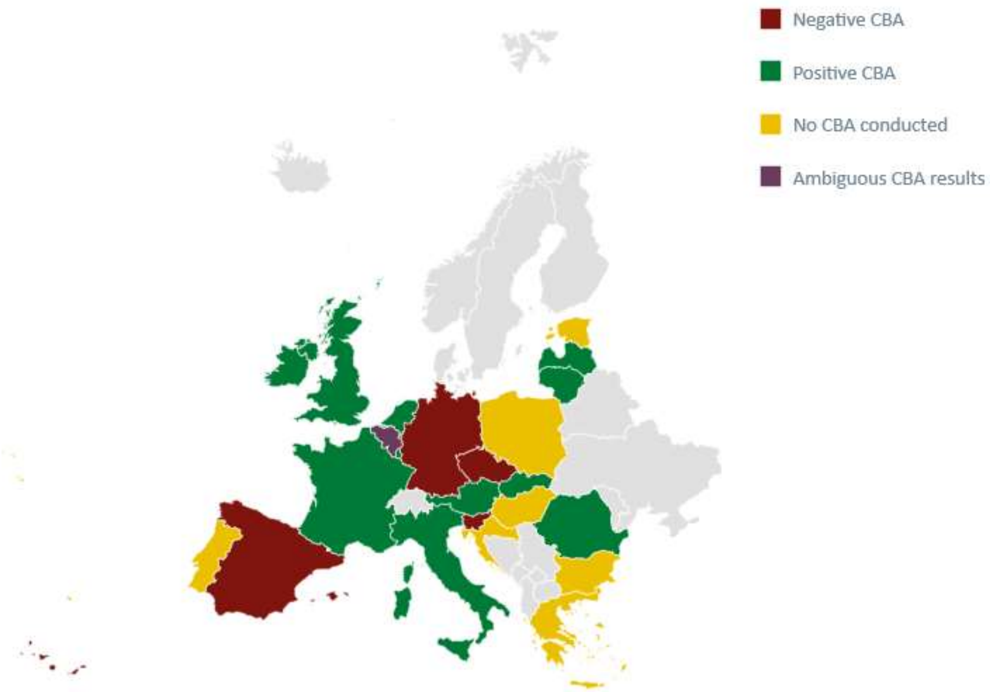
54 Five Member States conducted two distinct studies on costs and benefits before 2013 and between 2013 and 2018, updating their estimates based on evolving market conditions and results from their own roll-out, where relevant. Furthermore, Belgium accounted for three distinct CBAs, one for each region of Brussels, Flanders, and Wallonia.

55 This is calculated based on available data for the different CBAs. Are missing the estimates for Denmark and Flanders, for which per meter benefit estimates are not available.

56 The reasons for this are unclear

did not conduct a gas specific CBA[57]. This geographical state of play is summarised in Figure 12.

Figure 12 Map of CBA results in each Member State



Source: European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

Despite the relatively limited roll-out of gas smart meters in the European Union, the market has evolved since 2012 which raises the question of whether requirements for gas smart meter deployment should be revisited:

- Energy efficiency has become a focus to reach the net zero target presented in the Green Deal.[58] Increased consumer awareness of energy consumption may help reduce energy consumption.
- Renewable and decarbonised gases are being increasingly produced and injected into the gas grid. This creates greater requirements for flexibility, particularly at the distribution grid level to which smaller customers are typically connected. This implies that more system management needs to be done at the distribution level to ensure that capacity constraints are eased. [59]

[57] These are Bulgaria, Croatia, Estonia, Greece, Hungary, Poland, and Portugal.

[58] European Commission, COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE EUROPEAN COUNCIL, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS, The European Green Deal, 11.12.2019

[59] P.71 of Frontier et al's (2019) report, 'Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU - Final report' describes two possible drivers of the need for increased flexibility. First, the constant supply of renewable gases from biomass may result in congestion in summer in decentral, rural places when demand for e.g. heating is very low. Second, intermittent renewable electricity may be used to produce synthetic gases and injected into the grid. However, this means the intermittency of renewable electricity sources will be imported to the gas sector. This the need for flexibility is particularly acute at distribution level given that distribution grids have limited linepack flexibility (ability to store gas within the grid), compared to transmission grids.

In light of these developments, we investigate whether more ambitious requirements for rolling out gas smart meters may be beneficial.

Definition of policy options

The policy options as defined below gradually introduce more requirements regarding the roll-out of smart gas meters across the EU.

- ***Counterfactual Option 0+*** *(business as usual - updated)*, under this option only an update of the EU framework will take place in terms of the requirement for conducting CBA for the roll-out of smart metering under the Gas Directive, while the core framework will remain the same including the part covering access to data (Annex I.1(h) of Directive 2009/73/EC). Under this option, the respective gas metering provisions under the Energy Efficiency Directive are accordingly incorporated in the new gas market legislation.
- ***Option 1,*** introduction of more ambitious requirements regarding the roll-out of gas smart meters similar to the requirements of Directive 2009/72/EC (Electricity Directive) i.e. where roll-out of smart meters (possibly to a subset of properties) is judged to be cost effective, setting a timeline of 10 years for full roll-out, with a binding target of 80% roll-out within 8 years of a positive assessment. [60] Additionally, in cases where a roll-out of electricity smart meters is implemented, potential synergies have to be considered and Member States, under this option, are asked to carefully assess the possibility to use common ICT infrastructure in electricity and gas smart metering systems so as to keep in check associated costs.
  - Moreover, under this option, Member States will have to (i) monitor the deployment where applicable and the delivery of benefits to consumers, and (ii) revise, where this is negatively assessed, their CBAs at least every four years or in response to technology and market developments.
  - Finally, regarding metering data, under this option, specific provisions are introduced on data management and interoperability requirements and procedures for access to data by eligible parties, in a similar manner with the relevant requirements under the recast Electricity Directive (EU) 2019/944 (Articles 23 and 24).
- ***Option 1+,*** introduce additional requirements for selective roll-out of gas smart meters under specific use cases such as the connection of gas heat pumps.
- ***Option 2,*** in addition to option 1 introduce concrete requirements with regard to the functionalities of gas smart meters in a similar manner, and as relevant, for the functionalities that have been introduced for electricity smart meters, including under the recast Electricity Directive. According to the EC benchmarking studies on smart meters[61], the Commission Recommendation 2012/148/10 defined 10 common minimum functionalities for electricity smart

[60] As part of this option, Member States might also be required to consider alternative measures that could achieve similar benefits. For example, some studies have shown that simply providing consumers with greater information on their energy consumption (including time of use information) can boost awareness of energy use and help drive energy savings linked to behaviour change (see for example Concerted Action Energy Efficiency Directive, “Smart meters and consumer engagement”, May 2015)

[61] European Commission, Benchmarking smart metering deployment in the EU-28, December 2019

metering systems, among which 9 are also relevant to gas smart metering which are described below:

1) Provide readings directly to consumer and/or any 3rd party
2) Upgrade readings frequently enough to use energy saving schemes
3) Allow remote reading by the operator
4) Provide 2-way communication for maintenance and control
5) Allow frequent enough readings for network planning
6) Support advanced tariff systems
7) Remote ON/OFF control of the supply AND/OR flow or power limitation (although we understand that this is not typical in gas, due to safety concerns)
8) Provide secure data communications
9) Fraud prevention and detection

Cost benefit analysis

We first note that in conducting the cost benefit analysis, we assume that EU climate energy targets are met regardless of the scenario (including the counterfactual). Our assessment therefore focuses on the potential impact of the different options on the costs of meeting those targets.

Second, we note that the nature of costs and benefits, and the direct impacts associated with **rolling out** smart meters, will not be influenced by the options considered (except maybe in the case of a selective roll-out). We therefore describe the general costs and benefits associated with such roll-out, before describing how these may (most likely indirectly) vary across each option considered.

It is worth noting that in many Member States, industrial users consuming above a certain threshold of gas are already required to be equipped with a meter that allows them to enter flexibility contracts with the DSO. We therefore review the benefits associated with a smart meter roll-out mostly from the perspective of household and smaller business customers.

General description and assessment of the costs and benefits associated with smart-meter roll-out

This section is structured as follows:

- The first describe separately:
  - the costs associated with gas smart-meter roll-out ;
  - the benefits associated with gas smart-meter roll-out; and
  - the net impact.
- We then describe the distributional impacts of
  - The costs identified ;
  - The benefits identified ; and
  - The net impact.

Costs

The main costs associated with a gas smart meter roll-out, regardless of the entity carrying it out, are the associated investment and operational costs, which are listed below:

- Capital expenditure (CAPEX) items include:
  - Investment in IT and Telecom
  - Investment in smart meter
  - Investment in in-home display
- Operational expenditure (OPEX) items include:
  - Network management and front end
  - IT maintenance
  - Change management
  - Call centre and customer service
  - Unplanned renewal and failures of smart meter
  - Consumer engagement program

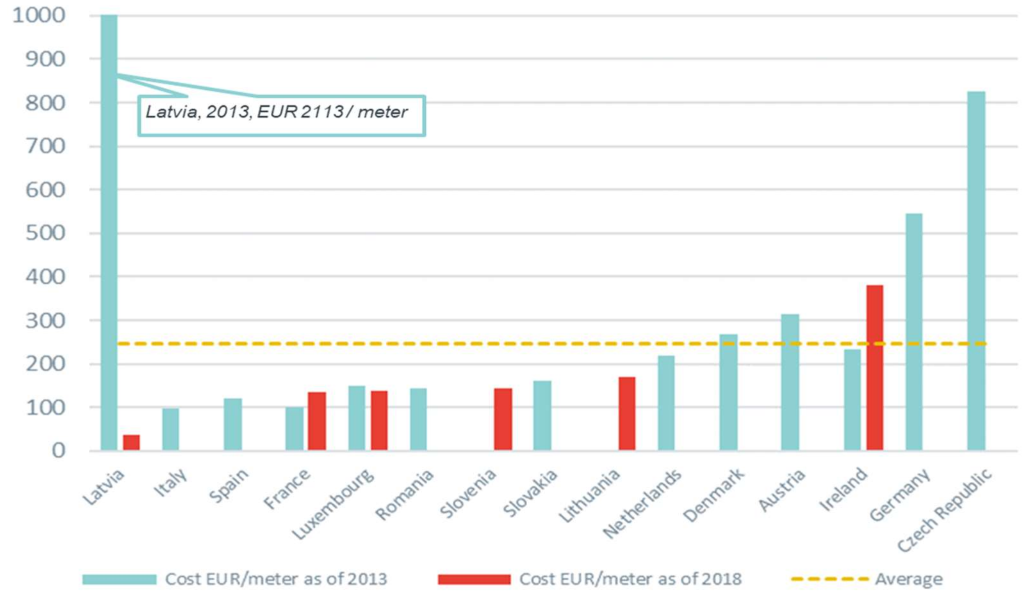
As of 2018, most recent estimates across all Member States indicated that there remained large differences in per-meter costs across the EU, with the highest price point at EUR 826 / meter in the Czech Republic and the lowest at EUR 38/ meter in Latvia[62].

These cost differences could be explained by a number of factors such as the type of meter considered, the cost of living, the economies of scale that could be achieved etc. Wide and unexplained disparities in cost estimates between countries make it difficult to draw a conclusion on an average cost for a “typical” meter from these CBAs. Although more recent evidence from countries that are actually rolling out smart meters suggests costs in the range of EUR 100-350 / meter.

See Figure 13 for the full cost breakdown by Member State, in ascending order of most recent available cost estimates.

[62] This EUR estimate and all EUR estimates of costs and benefits cited in this report are based on data provided by Member States through their individual CBAs. For the most part therefore, these are given in Net Present Value for the year in which the CBA was carried out. As such, the specific estimates are not meant to be compared like-for-like but instead serve as both a rough estimate of actual smart meter costs and benefits at the time of their estimation and as internally consistent estimates of costs and benefits within each individual CBA.

Figure 13 Costs estimated in Member State CBAs

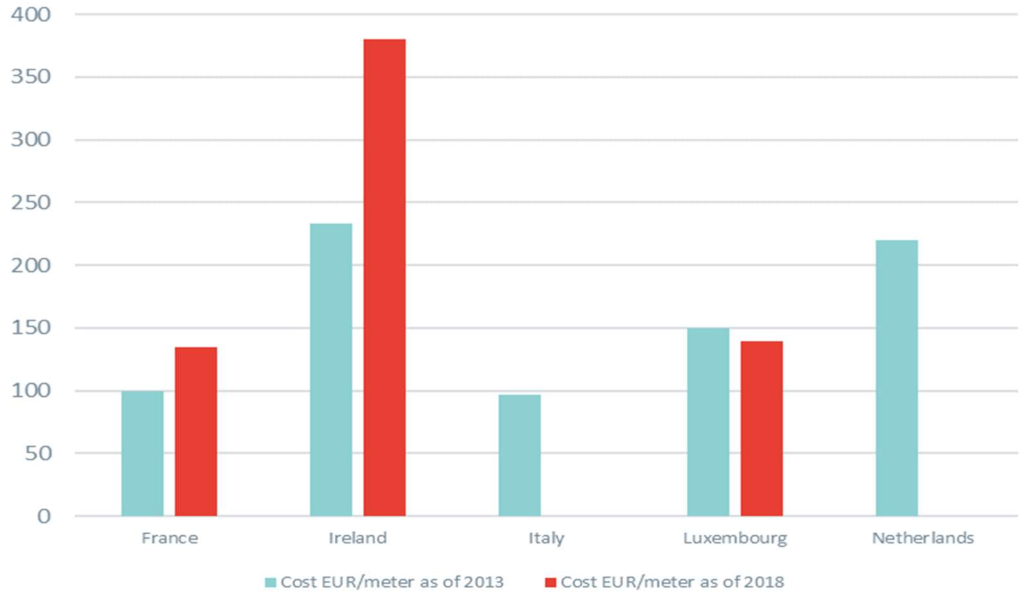


Source: *European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019*

Notes: *The average line is to be read as the average per meter cost of the last available cost estimate for each Member State. The y-axis has been cropped at EUR 1000 / meter for readability, but the 2013 Latvian cost estimate is higher (EUR 2113.64 / meter).*

For the five Member States that have begun rolling-out gas smart meters, the costs varied less both between countries and across time, with a maximum estimated cost of EUR 380 / meter for Ireland and a minimum of EUR 97 / meter in Italy. We note however that for two out of three countries that have updated their 2013 estimates of costs, 2018 estimates show an overall increase compared to 2013 estimates. The breakdown can be found in Figure 14.

Figure 14 Costs estimated in Member States where a roll-out has begun



Source: European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

Note: Italy and the Netherlands carried out a single CBA, before 2013.

Benefits

The benefits included in the national CBAs vary somewhat from Member State to Member State and depend mainly on their national priorities.

- All 17 Member States who carried out a CBA for which data is available[63] included an estimate of the benefit to DSOs in the form of operational savings linked to automation and gained efficiency meter reading and operation.
- Furthermore, all but two[64] CBAs included an estimate of consumer savings linked to gains in energy efficiency.
- Other benefits that were incorporated by the majority of CBAs include savings to the DSO linked to operation and maintenance of assets and technical and non-technical loss reduction.
- Further benefits considered by a minority of Member States include increased competition in the retail market, reinforced outage management, and CO2 and air pollution reduction.

Figure 15 summarises the available estimates of these benefits for each Member State[65], in ascending order of most recent benefit estimates, with Germany finding the highest benefit at 493€/meter and Slovenia finding the lowest at EUR 26 / meter.

The high level of disparities observed in these benefit estimates depend on a number of different conditions within the individual Member States and their

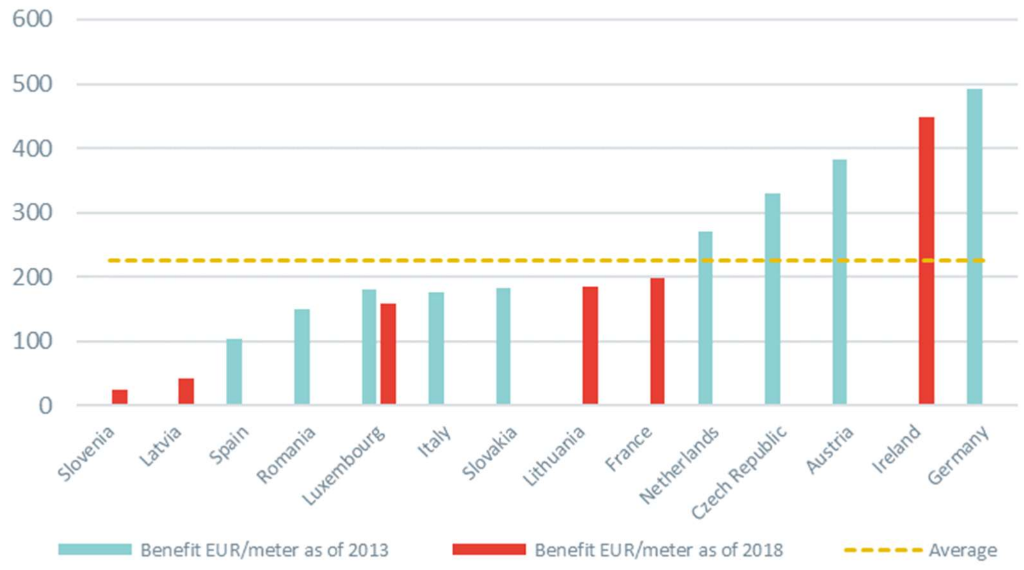
[63] This data is not available for Denmark, Finland, Latvia, or Slovakia

[64] Neither Wallonia nor the Czech Republic took these benefits into account.

[65] Per meter benefit estimates are not available for Denmark whereas per meter costs are. Neither costs nor benefits were available for Flanders. See Figure 14.

respective gas markets. These can include but are not limited to existing national consumer energy-saving initiatives, the share of gas in domestic energy consumption, the number of expected new builds over the period covered by the CBA.

Figure 15 Benefits estimated in Member State CBAs



Source: European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019 & GRDF.

Notes: The average line is to be read as the average per meter benefit of the last available benefit estimate for each Member State. French benefits per meter are calculated on the basis of GRDF's statement that they aim to install 11 million gas smart meters by the end of 2024.

We discuss the main benefits identified by Member States in more details below.

Benefits linked with energy efficiency

Installing smart meters can increase consumer participation as this will enable them to be more aware of their gas consumption. This, in turn, can lead to energy savings as consumers receive more frequent usage information, are more sensitive about their consumption, and consume less.

There is some evidence for such an impact. For example:

- In Ireland, a gas customer behaviour trial (CBT) was carried in 2011, in advance of the gas smart meter CBA[66]. This trial found that both receiving more regular gas consumption readings available and having an in-home-display meter reduced energy consumption by 2.9%. The largest change in energy consumption was observed in middle-income groups as opposed to high and low earners, suggesting that high earners may have a higher willingness to pay for gas and low earners may already be aware of consumption levels, and therefore have limited scope for a further behavioural response.
- In France, a 2011 pilot project was carried out where 437 households who received a smart meter and a number of land developers, landlords and

[66] CER, CER11180a, May 2011

community energy were surveyed. This study showed that smart meter installation leads to an average of 1.5% reduction of annual gas consumption due to individual and collective behaviour changes.[67]

- In Great-Britain, British Gas estimated that during the rollout, smart meter consumers had reduced their gas consumption by 2.5% over the first two years.[68] However that there has been limited research in Great Britain into the extent to which energy savings from smart meters are likely to be sustained in the long term, and the available evidence is inconclusive.[69]

Hence, whilst some studies show that gas smart meters can enable energy savings, it is too early to say whether there may be a long term impact. In a number of Member States, the rollouts are not yet completed so a number of years may be needed before more robust analyses can be carried out on the impact of gas smart meters.

Given that we assume that the net zero target is met in the counterfactual, the benefits associated with any reduction in energy consumption are the avoided resource costs of consumption. These include reduced energy production and/or import costs, reduced transport and distribution costs and lower costs associated with meeting climate targets (the emissions reductions achieved through greater efficiency allow more expensive abatement measures to be avoided – i.e. they can be valued at the marginal abatement cost).

Benefits linked with network optimisation

Smart meters can enable a better optimisation of the network from:

- Operational savings from doing automated readings versus manual reading previously (saved time spent on site visits)
- Reduction of non-technical losses (less sensitive to administrative errors, energy offtake less sensitive to fraud, fraud can be more easily identified)
- Avoided investments from increased energy efficiency and from having more flexibility sources available

These first two points were consistently included in the different Member States' CBAs and accounted for an overall large percentage of the benefits calculated. In the case of both France and Luxemburg for example, they represented the second largest benefit, after the benefit linked to consumer energy bill reduction. [70],[71]

On the last source of benefit listed (avoided investments from having more flexibility sources), we note that flexibility sources may come from demand-side responses (DSR) enabled by smart meters. DSR refer to actions carried out by consumers to displace their consumption of energy when responding to price signals. For example, at a time when the system is constrained and energy becomes more expensive (in times of scarcity for example), DSR participants can be remunerated to turn down their consumption. Smart meters might help facilitate

[67] Sopra/Poyry, Etude Comptage évolué gaz, 2013

[68] National Audit Office, Department for Business, Energy & Industrial Strategy, Rolling out smart meters, 23 November 2018

[69] Ibid

[70] Sopra/Poyry, Etude Comptage évolué gaz, 2013

[71] Schwartz and Co, Etude Economique à long terme pour la mise en place de compteurs intelligents dans les réseaux électriques et gaziers au Luxembourg – Rapport Final, February 2011

DSR by enabling consumers to manage their energy usage (for example, allowing them to schedule usage for particular times or to vary it on demand to save money).

In the gas market, and as confirmed from conversations with distribution network operators[72], we expect DSR to mainly come from industrial users or producers rather than from residential or smaller business users:

- The potential for DSR in smaller customers is therefore likely limited to those with heating appliances such as gas heat pumps (which can store heat) and hybrid heat pumps (which can choose to use electricity instead of gas), as the gas consumption can be more easily modulated without impacting the heat produced.
- However, even with smart meters, gas consumers would not face prices that change throughout the day. As such, smart meters alone would not provide them with incentives to adapt their consumption throughout the day (in contrast to the electricity market, where wholesale prices may vary in 15-minute intervals).
- In addition, gas is mostly used for heating purposes in the residential sector. The demand for gas is therefore price-inelastic and instead strongly correlated with temperatures. Consumers have limited ability to shift consumption from one day to another, in response to day-to-day fluctuations in wholesale prices.
- Further, the hybrid heat pumps that have been rolled out so far tend to optimise the electricity consumption by switching to gas when electricity is more expensive. For example, the Freedom project rolled out by Western Power Distribution in South Wales mentions that "*The aggregation interventions made full use of PassivSystems' aggregated demand management technology, and addresses the central challenge of the Freedom Project: the scenario where many homes have moved over to heat pumps in order to decarbonise home heating, but the electricity network does not have enough capacity to meet the load. The project's proposed solution to this problem is the hybrid heating system: when the electricity network nears its capacity, heating load can be intelligently switched over to gas.*"[73]
- Such a solution as described above therefore requires an electricity smart meter, but not necessarily a gas smart meter. In addition, we note that cold spells, when gas is likely to be in high demand and expensive, and when therefore DSR actions could help alleviate some of the network constraints, are likely to be associated with high electricity prices as well. This may occur even more as the share of electric heating increases across Member States in the future[74]. It seems unlikely that there would be much scope (even with hybrid heat pumps in place) to reduce household gas demand at peak.

For the above reasons, benefits related to flexibility are rarely mentioned or quantified in the Member State CBAs and distribution network operators have

[72] On June 9th 2021, Frontier Economics carried out an interview with EU DSO representatives including Thüga Germany, Eurogas, Cedec, Fulvius, GD4S/Italgas, GEODE, Wienernetze and GD4S/GNI. On June 21st 2021, Frontier Economics also carried out an interview with GRDF.

[73] https://www.westernpower.co.uk/projects/freedom

[74] Heating & Cooling outlook until 2050, EU-28, Hotmaps EU grant 723677

confirmed in interviews[75] that the value added from gas smart meters in reducing network costs was low.

Industrial users however can, and in many Member States already do, have flexibility contracts with DSOs. This is for example the case at least in Germany and France where large customers can enter into interruptible contracts with the network operator.[76] For these purposes, they are already equipped with meters which allow their participation in the flexibility market. In fact in some Member States (such as Austria, Germany and Slovenia), clients consuming more than a certain volume are obliged to be equipped with a metering equipment. The value added of installing a smart meter to bring more flexibility to the system is therefore diminished. This view was again confirmed by DSOs.[77]

Benefits linked with increased retail competition

Rolling out gas smart meters can also enhance retail competition by increasing access to time of use data for both consumers and suppliers.

The Irish CBA, for example, outlined three retail competition benefits linked to gas smart meter deployment:

- Consumers who are more informed about their usage are able to more make more informed and personalised decisions regarding both their gas supplier and their chosen tariff scheme;
- Suppliers who also have access to a large quantity of detailed usage data will be able to infer more detailed consumer profiles and tailor their offers to these. Usage of this data can also boost innovation for gas retailers; and
- Real-time information on energy consumption reduces incidents of billing disputes, and therefore facilitate contract closure. In this way, switching costs are lower for both consumers and suppliers, lowering barriers for consumers to switch between retailers. In the Irish CBA this benefit was estimated to be around EUR 0.65 / meter saved on contract closures per year.[78]

Although retail competition benefits are difficult to quantify, it would follow that any well-regulated energy market in which consumers also have the choice between different retail gas suppliers, would also reap competition related benefits.

We note however that according to the EC report on benchmarking smart metering deployment in the EU[79], this benefit was not frequently encountered in Member States' CBA on the roll-out of gas smart meters (only 7 out of 17 Member States

[75] On June 9th 2021, Frontier Economics carried out an interview with EU DSO representatives including Thüga Germany, Eurogas, Cedec, Fulvius, GD4S/Italgas, GEODE, Wienernetze and GD4S/GNI. On June 21st 2021, Frontier Economics also carried out an interview with GRDF.

[76] CEDEC, EDSO for Smart Grids, eurelectric, Eurogas and GEODE, Flexibility in the Energy Transition – A Toolbox for Gas DSOs, February 2018

[77] On June 9th 2021, Frontier Economics carried out an interview with EU DSO representatives including Thüga Germany, Eurogas, Cedec, Fulvius, GD4S/Italgas, GEODE, Wienernetze and GD4S/GNI. On June 21st 2021, Frontier Economics also carried out an interview with GRDF.

[78] CER, CER11180c, December 2011

[79] European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

or regional authorities[80] that carried out at least one gas smart meter CBA considered this impact).

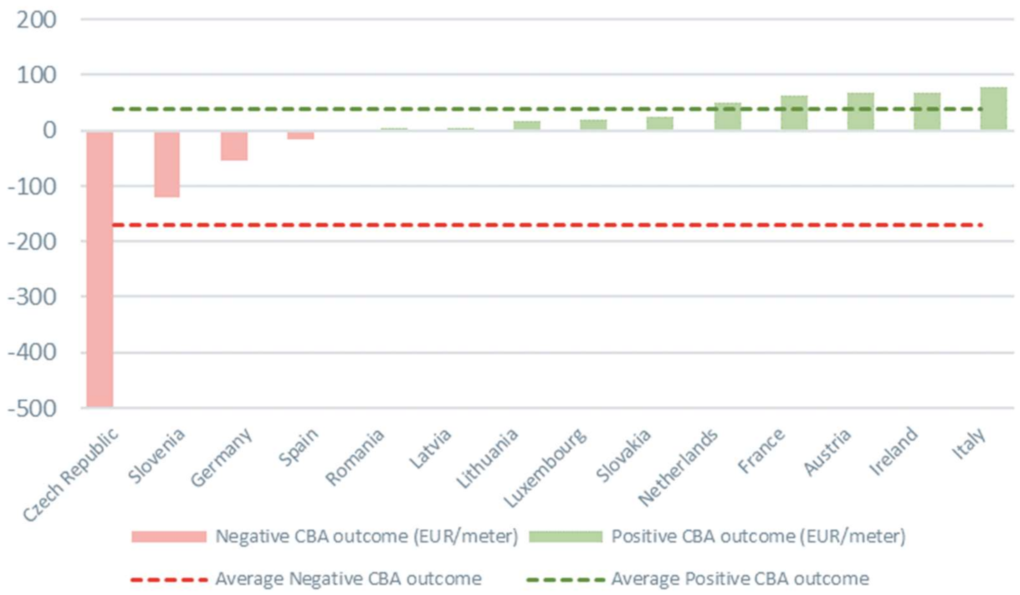
Overall costs and benefits

The results of this exercise at the national level is reflected in the CBAs carried out by the Member States. A total of four countries had net negative cost associated with a potential smart meter rollout and nine have a positive result. The breakdown of these can be found in Figure 16. On average, we observe that:

- For the CBAs that came out negative, the average net cost is of EUR 171 / meter
- For the CBAs that came out positive, the average net benefit is of EUR 40 / meter

The disparities in cost and benefit estimates across Member States and the different conclusions drawn from the CBAs highlight the importance of conducting the analysis for each Member State, and of taking forward smart meter roll-outs where the case is positive (as opposed to relying on a positive conclusion for the EU as a whole). It is also notable that estimated costs and benefits (where they have been reassessed by Member States) can change significantly over time, as new evidence comes to light and as views on how the gas system will evolve are updated. This highlights the importance of periodically revisiting the analysis.

Figure 16 Net CBA outcome by Member State (EUR / meter)



Source: *European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019*

Note: *The results presented in this graph represent the most recent CBA findings for each Member State, where available, as presented in Figure 13 and Figure 15. The Average CBA outcome lines are to be read as the average CBA outcomes of the Member States for which the most recent CBA is negative and the Member States for which the most recent CBA is positive, respectively.*

[80] Belgium conducted 3 separate CBAs in Brussels, Flanders and Wallonia – the distribution grids in these 3 regions are regulated separately by 3 different NRAs.

Distributional impacts and summary of the costs and benefits identified

Distribution of costs

The costs described above will be initially incurred by the entity carrying out the smart meter roll-out. According to the benchmark conducted by the European Commission on smart metering deployment, in nearly all Member States that have so far undertaken a smart meter roll-out (in both gas and electricity), these have been DSO-led.[81] In some occasions (for example in the UK), suppliers have undertaken the roll-out of smart meters.

- In case of a DSO-led roll-out, the costs of the roll-out may (depending on the regulatory regime in place) be passed on to customers through network access tariffs for the gas distribution grid
- In case of a supplier-led roll-out, it is likely that a levelisation mechanism is put in place to ensure that costs are distributed fairly between suppliers (i.e. that the costs are not all borne by suppliers whose customers are particularly willing to receive meters). Provided that the retail market is competitive, the resulting costs of smart meter deployment will are also likely to be passed through to customers.

In either case, provided that the retail market is competitive, the resulting additional costs can be viewed as akin to an additional ‘tax’ on gas consumption. As household gas demand tends to be rather inelastic[82], consumers are likely to bear most of the burden arising from an increase in cost of procuring, transporting and distributing gas. We note that these costs will be incurred in the short to medium term as the smart meters are being rolled-out and their costs are passed through to consumers (the exact timing will depend on the regulatory regime of each Member State).

Distribution of benefits

Consumers will gain from each of the benefits listed above:

- Energy efficiency savings will lead to a reduction in consumers’ bills equal to the volume of energy saved multiplied by the average cost of gas provision.
- The savings associated with network optimisation will lead to lower tariffs from using the distribution grid (depending on the regulatory regime). This in turn should be reflected in lower bills for (gas) consumers. As a reminder, we assume that the net zero target is met in the counterfactual as well as in all options. Accordingly, we assume that the impact of the costs of decarbonisation on network tariffs are embedded in all options and we describe here the incremental impact of smart meters through network optimisation.
- Increased retail market competition will also lead to lower consumer prices.

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[81] European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

[82] Whilst there is uncertainty about estimating the elasticity of demand for gas consumption, some studies suggest that it is rather inelastic for households. See for example RSCAS 2016/25 Robert Schuman Centre for Advanced Studies Florence School of Regulation Climate, A meta-analysis on the price elasticity of energy demand, 2016; or Maximilian Auffhammer and Edward Rubin, Natural Gas Price Elasticities and Optimal Cost Recovery Under Consumer Heterogeneity: Evidence from 300 Million Natural Gas Bills, January 2018

We note that these benefits will likely materialise in the medium to long term, after smart meters have been rolled out.

Broadly, therefore, the benefits to consumers will reflect the benefits to society described above. One caveat however is that retail prices may not factor in the full value to society of the reduction in abatement costs when achieving the objective of lower in greenhouse gas emissions.

But even where this is not the case (for example, because some Member States do not tax gas consumed by households), society at large will still benefit from the reduction in abatement costs. We therefore attribute this benefit to consumers in our analysis.

Overall distributional impacts

We describe below the net impact of rolling out smart meters on different stakeholders:

- DSOs/Retailers: whilst these entities may initially incur the CAPEX and OPEX costs for the roll-out of smart meters, these are likely to eventually be passed onto consumers (either through the distribution tariffs via regulatory regime or through market prices). The impact should therefore be neutral.
- Producers/importers: similarly to consumers, the net impact on producers will be a function of gas prices and volumes sold and we expect this impact to be overall negative:
  - The volumes sold should decrease as a result of deploying gas smart meters, from energy efficiencies achieved.
  - The lower demand should lead to a fall in prices received by producers.
- Consumers: As explained above, the costs and benefits to consumers will broadly reflect the costs (deployment of smart meters) and benefits (energy efficiency, network optimisation and retail competition) to society. The net impact of rolling out gas smart-meters is uncertain: as we have seen from Member States' individual CBAs, some foresee a net benefit whilst others foresee a net cost. In addition, there is so far too little feedback from the roll-outs that have started to understand what benefits do actually materialise. However, if the balance of costs and benefits to society is positive, and a roll-out is therefore carried out, the same will be broadly true for the net consumer impact.

Assessment of each policy option

Counterfactual: Option 0+ (business as usual – updated)

Under this option, the new gas market legislation will include requirements for Member States to implement gas start metering systems which may be subject to a CBA. As of 2018, at least 9 Member States did not conduct a gas smart meter roll-out CBA even though they have a natural gas network.[83] This option would

[83] These are Bulgaria, Croatia, Denmark, Estonia, Greece, Hungary, Poland, Portugal and Sweden according to European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

therefore incentivise Member States to evaluate the magnitude of the potential benefits from rolling out smart meters mentioned above.

This option is likely to lead to direct costs related to carrying out and reviewing the cost and benefit assessment (this could be done by Member States officials, or the Member State could mandate a local authority – such as the NRA – to do this). We note that these costs are typically not estimated as part of the Member States' CBA on the roll-out of smart meters and as such, we have not found any quantitative estimates. However, they are likely to be relatively small compared to direct CAPEX and OPEX costs.

The benefits from this option would be to potentially unlock the net benefits estimated if the CBAs are positive and Member States decide to roll-out gas smart meters. However, given that this option does not require Member States to roll-out smart meters if the CBA is positive, there is a risk that positive CBAs are not acted on. This was the case for example in Austria, Latvia, Romania, Slovakia and Slovenia where CBAs with positive results were conducted but as of 2020, no systematic roll-out of smart gas meters was planned.[84],[85]

Option 1, introduction of more ambitious requirements regarding the roll-out of gas smart meters

Compared to Option 0+, Option 1 would impose a timeline of 10 years and a target of 80% (within 8 years from a positive assessment) where the deployment is positively assessed for Member States to roll-out gas smart meters upon realising a positive CBA. This would therefore ensure that the benefits estimated (and described before) do materialise in case of a positive CBA.

By definition the ex-ante net welfare impact of a smart meter roll-out should be positive, but there may be value in evaluating the net impact of the roll-out after it has started to check that the ex-post impact is also positive. [86]

Member States would also be required to monitor the deployment and the delivery of benefits to customers and revise the CBA every 4 years in case of a negative assessment. The direct impacts of this feature are described below:

- If Member States are not doing so already (as shown in Figure 13 and Figure 15, only 6 Member States had updated their CBAs between 2013 and 2018, 3 of which did so after launching a gas smart meter roll-out), this would increase administrative costs compared to the counterfactual associated with re-evaluating a negative CBA at least every 4 years. It may also increase overall

[84] While no widescale smart meter roll-out in Austria is underway, it is possible for individual consumers to request smart gas (and water) functionalities to be added to their electric smart meter at time of roll-out. This however remains a limited possibility as of 2020, as many providers carrying out electric smart meter installation do not have the technical capacity to offer these add-on functions. Source: E-control, BERICHT ZUR EINFÜHRUNG VON INTELLIGENTEN MESSGERÄTEN IN ÖSTERREICH 2020

[85] https://www.febeg.be/fr/domein/compteurs-intelligents-smart-meters

[86] We note that this option implies that a positive CBA will necessarily lead to the roll-out of smart meters to properties in which their deployment has been positively assessed, To avoid the risk of being 'locked in' to meeting deployment targets which later prove to be more costly or less beneficial than expected, we expect that Member States will adapt their roll-out strategies:

- **Ex-ante**, by conducting robust CBAs, considering uncertainty in cost and benefit estimates, and defining "low-regret" roll-out strategies (i.e. roll-out limited to segments where the benefits are the most certain) that leave room for further expansion of the roll-out programme at a later stage; and
- **Ex-post,** for example by changing the segmentation of timing of their roll-out.

administrative costs if Member States that are rolling out smart meters would not otherwise have planned to monitor the delivery of benefits.

- It would however help to ensure that, in the case of a negative assessment, unforeseen future technological advances and market evolutions can be taken into account so that if a future net positive impact is possible, it is identified.

We note that Option 1 would also require Member States to consider potential synergies with the roll-out of electricity smart meters, in terms of using common infrastructures for example. This is likely to reduce the estimated cost of roll-out without negatively impacting the benefits, thus potentially leading to more findings of a net positive impact.

It would also require that specific provisions are introduced on data management and interoperability requirements. Interoperability requirements would ensure that consumers can switch supplier without having to adapt their smart meters, which would enhance retail competition without impacting the roll-out costs.

The indirect impacts of this option would therefore be that more findings of positive CBAs materialise from considering synergies and re-evaluating the assessment over time to account for technological improvements and market changes. This could lead to more roll-out, and the regular reviews and monitoring of costs and benefits would limit the risk that smart meters do not deliver the benefits foreseen.

Overall, therefore, while Option 1 may lead to additional direct administrative costs, these are likely to be of an order of magnitude smaller than the potential benefits associated with any additional smart meter roll-out.

Option 1+, introduce additional requirements for selective roll-out of gas smart meters under specific use cases such as the connection of gas heat pumps.

Compared to Option 0+, this option encompasses all the features of Option 1 but also introduces additional requirements for Member States to consider a selective roll-out of gas smart meters for specific use cases when conducting their CBA.

This will therefore induce additional direct administrative costs (compared to Option 0+ and Option 1) as the CBAs will need to consider an additional scenario.

The indirect net benefits compared to Option 0+ and Option 1 are that it could increase the findings of positive CBAs by focusing on use cases which show the most potential. This, in turn and coupled with Option 1, could lead to unlocking more of these benefits for society in general.

However, in the case of gas heat pumps, we discuss above that whilst the fact that they can store heat may make them more likely to participate in DSR actions (and hence unlock network optimisation benefits), this is still limited by the lack of daily price signals in the gas market, and the fact that hybrid heat pumps may be used to optimise the electricity network rather than the gas network. As of yet, and as highlighted by DSOs, there is a lack of evidence of a particular gas smart meter benefit linked to heat pumps.

Overall, therefore, Option 1+ may involve slightly higher direct administrative costs than Option 1 and a small probability of a slightly higher benefit linked to additional cost-effective smart meter roll-out. We therefore assess it to have an overall similar net impact as Option 1 (compared to the counterfactual).

Option 2, in addition to option 1 introduce concrete requirements with regard to the functionalities of gas smart meters in a similar manner, and as relevant, for the functionalities that have been introduced for electricity smart meters under the recast Electricity Directive

As mentioned in the definition of options, the Commission Recommendation 2012/148/10 defined the following functionalities for gas smart metering systems which Member States could consider:

1) Provide readings directly to consumer and/or any 3rd party
2) Upgrade readings frequently enough to use energy saving schemes
3) Allow remote reading by the operator
4) Provide 2-way communication for maintenance and control
5) Allow frequent enough readings for network planning
6) Support advanced tariff systems
7) Remote ON/OFF control of the supply AND/OR flow or power limitation (although we understand that this is not typical in gas, due to safety concerns)
8) Provide secure data communications
9) Fraud prevention and detection

Functionalities 1), 2) and 8) seem to be the most important functionalities to engage consumers in energy efficiency measures, as they will ensure that data is communicated and the data privacy and security is respected. These functionalities would therefore be important to unlock the efficiency savings that most Member States identify in their CBAs.

Functionality 3) will ensure that savings related to time spent by the DSO (or appropriate stakeholder) on site visits for meter reading is saved, which is also a benefit highlighted in most CBAs conducted. Functionality 9) will also help to reduce costs for DSOs and retailers by reducing the number of frauds.

In the gas market, it is unclear whether functionality 6) will add a lot of value, since the time frames used are much wider than in the electricity market (hours instead of minutes or second), reducing the scope of advanced tariff systems. In addition, given that gas demand tends to be rather inelastic, consumers may not be as sensitive to such tariff systems in the same way that they would be in the electricity market. However, we note from the CBA conducted in Ireland that seasonal tariffs for gas were considered.[87] The information provided in Member States' CBAs does not allow to draw a full cost benefit analysis of this functionality, but the rationale for it seems diminished.

We note that all Member States that have started a roll-out of smart meters included functionalities 1), 3), 4), 8) and 9).

[87] Commission for Energy Regulation, Cost-Benefit Analysis (CBA) for a National Gas Smart Metering Rollout in Ireland, CER11180c, 11th October 2011

Three Member States[88] did not include functionality 7) and two Member States[89] did not include functionality 6). The other Member States included both functionalities.[90]

Therefore, it seems that the following functionalities will enable the benefits considered to materialise :

- Providing consumers with frequent enough readings to allow efficiency savings;
- Allowing DSOs to do remote readings, have frequent enough readings for network planning purposes and enabling fraud prevention and detection; and
- Providing secure data communications.

However, as discussed above, it is less clear that functionalities relating to implementing support advanced tariff system will bring significant benefits in the gas market.

We note that rolling out some of these functionalities may be less costly if infrastructure from the deployment of electricity smart meters are shared, which should help to ensure that the net impact of these functionalities is in fact positive. We note that this option will require Member States to consider the synergies between the roll-out of gas and electricity smart meters.

Overall, this option therefore includes some minor additional direct costs compared to the counterfactual and Options 1 and 1+, as Member States will need to ensure and monitor the fact that the minimal functionalities are included in the CBAs and implemented when a roll-out is deployed.

But the requirements are meant to ensure that useful data is communicated for energy savings and network planning purposes, and that data privacy and security is respected. They can therefore enable the benefits estimated to actually materialise and ensure that the roll-out is successful, even though as the CBAs conducted so far have shown, Member States may already include the functionalities that are the most relevant as part of their roll-out.

[88] Italy, Luxembourg and the Netherlands. See European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

[89] Italy and the Netherlands. See European Commission, Benchmarking smart metering deployment in the EU-28 – Final report, December 2019

[90] It is not clear exactly how France, Flanders, Ireland, Luxembourg and the United Kingdom implemented this functionality

Summary of assessment of policy options

Figure 17 Summary of assessment of policy options, smart meters

	Option 0+	Option 1	Option 1+	Option 2
Environment, social and economic impact	0	+ Net benefit can be assumed, since roll-out is only required if CBA is positive (though uncertain in magnitude)	+ Could bring higher benefits if roll-out is enhanced for use cases that bring the most benefits. In practice, though, the relevance of smart meters for gas heat pump is unclear and this option brings additional administrative costs	++ Ensures that the smart meter functionalities which can ensure that benefits are actually realised are deployed.
Distributional impact on consumers	0	+ Consumers are expected to get most of the energy efficiency savings, network cost savings and retail competition benefits.	+	++
Distributional impact on DSOs/retailers	0	0 Neutral assuming that the costs incurred are passed on to consumers	0	0
Distributional impact on gas producers	0	- Efficiency savings should lead to lower volume and price of gas	- Efficiency savings should lead to lower volume and price of gas	-- Efficiency savings should lead to lower volume and price of gas. Greater negative impact under this option on the assumption that any incremental smart meter deployment is more effective due to clearer requirements on functionalities.

Source: Frontier Economics

ANNEX A FURTHER INFORMATION ON TOPIC I

A.1 The role of DSOs in gas quality management

Figure 18 The role of DSOs in gas quality management in the different member states

Role of DSOs	Countries	Description of DSOs' function
1. DSOs take a somewhat active role in the measurement and monitoring of gas quality	Austria	DSOs must verify that the entering gas respects the required provisions set in G31 (Gas quality standard of ÖVGW) and all the other codes of practice. It lies in the responsibilities of the DSOs to determine and monitor the gas composition as accurately as technically possible.
	Belgium	DSOs are in charge of taking care of the correct delivery pressure (important parameter for Wobbe Index). According to the HyLaw database, it is not yet defined who is responsible for gas quality measurement of H2 and other H2 injection related quality requirements, but it will be most likely the DSOs.
	Czechia	DSOs are responsible for the quality and the odorization of the gas supplied to the customers. If the injected gas does not meet the requirements, the DSOs are obliged to refuse the injection. The DSOs are supposed to establish and operate gas quality monitoring points, unless the monitoring points established and operated by the transmission system operator are sufficient.
	France	The DSOs do not control the gas quality they receive from the TSO. However, they control the quality and conformity to the national specifications of the biomethane injected on their networks.
	Germany	The DSOs are not obliged to monitor the gas quality daily but are obliged to publish the general gas quality characteristics of their distribution networks. In addition, DSOs are part of the specialist committees of DVGW.
	Ireland	Gas quality is monitored and regularly published by the Gas Networks Ireland (GNI), which is one company that represents both the TSO/DSO in Ireland.
	Italy	The main function of the DSOs (regarding gas quality) lies in the odorization of gas. In general, the TSO holds the responsibility for gas quality measurement and monitoring.
	Latvia	The DSOs are in charge to control that the gas quality of natural gas in its distribution network complies with the required gas quality standards. The DSOs are entitled to refuse the supply of natural gas or replacement gas if it fails to comply with the quality requirements.
	Poland	DSOs are responsible for meeting and controlling the required gas quality parameters, for performing gas quality parameters tests and for publishing the monthly gross calorific value of gas for specific points of their network online. In addition, as a member of the Polish Committee for Standardisation, the DSOs can help to define the gas quality standards.

	Portugal	The DSOs are responsible for managing the gas flows to ensure interoperability with 'connected infrastructures'[91]. In addition, the DSOs are responsible for measuring and monitoring the gas quality in the distribution network. Each distribution operator has to propose a methodology for monitoring that guarantees that the gas quality complies with the established technical characteristics and quality specifications.
	Slovak Republic	Alongside with the TSO, the DSOs are also responsible for measuring and publishing the gas quality online.
	Slovenia	In principle, DSOs are obliged to monitor the gas quality at entry points where gas production sources are directly connected to distribution systems. At the moment, however, no gas producers are directly connected to the distribution systems. .
	Sweden	The DSOs simulate the gas quality where no gas chromatograph is installed. The DSOs follow the CEN standard recommendations and rules. According to the HyLaw database, the DSOs are responsible for gas quality measurement of H2.
	The Netherlands	The DSOs are responsible for monitoring the gas quality of biomethane injection. In case the quality of biomethane doesn't meet the gas quality specifications, the DSOs are obliged to interrupt the gas flow. In general, TSO is responsible for monitoring the gas quality.
2. DSOs have no active role in the measurement and monitoring of gas quality	Estonia	The DSOs do not have an active role in measuring and monitoring gas quality. Responsibility lies with the TSO.
	Finland	The DSOs do not have an active role in measuring and monitoring gas quality. The TSO is responsible for monitoring. In case there is a biogas facility directly connected to the DSO network, 'the DSO is obliged *to follow* the gas quality standards'.[92]
	Hungary	The DSOs do not have an active role in measuring and monitoring gas quality. Responsibility lies with the TSO.
	Lithuania	The DSOs do not have an active role in measuring and monitoring gas quality. Responsibility lies with the TSO.
	Romania	The DSOs do not have an active role in measuring and monitoring gas quality. Responsibility lies with the TSO. However, the DSOs publish the gross calorific value (GCV) measured by the upstream operator online.
	Spain	The DSOs do not have a role in measuring and monitoring gas quality unless another DSO is connected downstream to their network for balancing issues.
3. No DSOs in Country	Malta	No DSO on Malta.

Source: Frontier Economics based on survey conducted by the European Commission; HyLaw database https://www.hylaw.eu/database/gas-grid-issues/injection-of-hydrogen-at-distribution-level-for-energy-storage-and-enhancing-sustainability/h2-quality-requirements

[91] It is unclear what this refers to in the survey; it may be a reference to the transmission system.

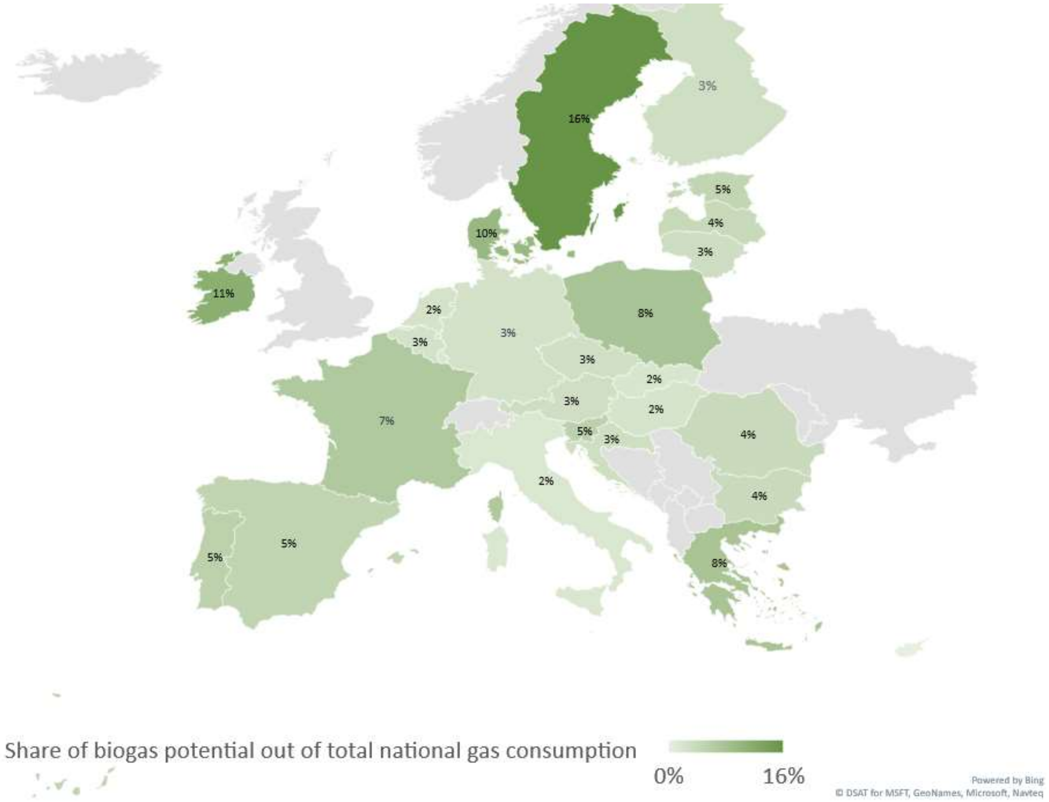
[92] It is unclear what this refers to in the survey; we believe it means that the DSO has to reject any biogas facilities that don't comply with the gas quality standards.

According to the member states, two occasions have occurred so far that required a network operator's intervention to stabilise gas quality in the system:

- Lithuania: The TSO refused to accept gas that did not meet the quality requirements due to a deviating dew point value
- Ireland: Gas Networks Ireland (GNI) had to enact its emergency procedures to isolate a pipeline that let un-odorised gas enter the network

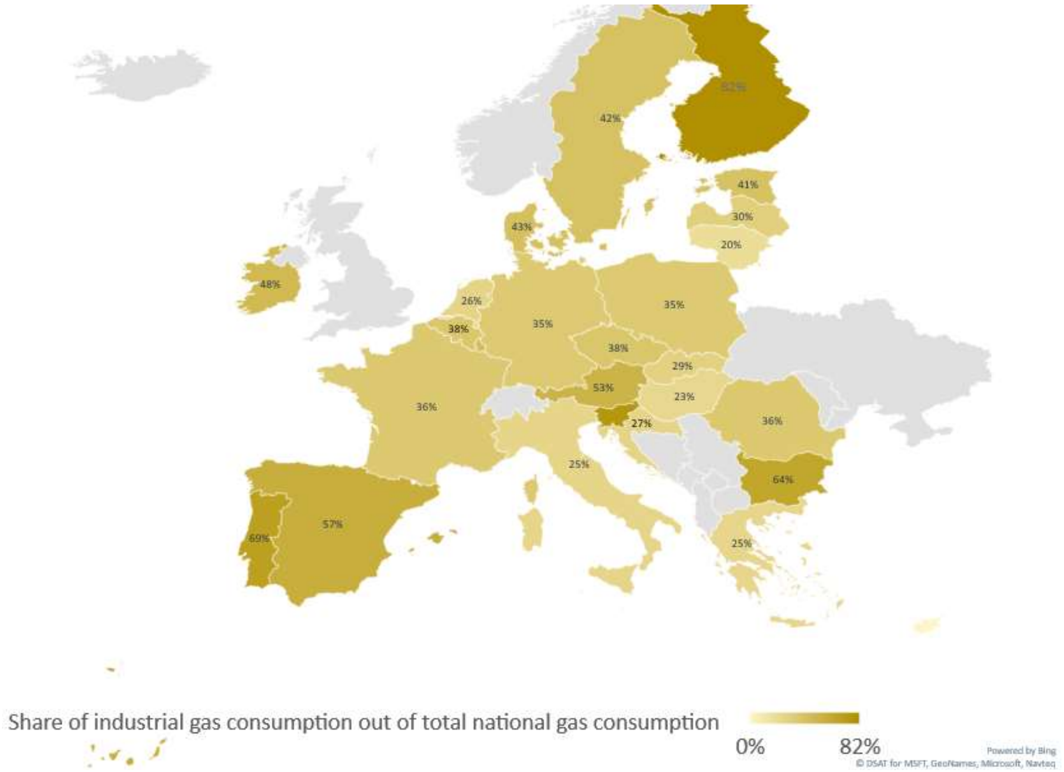
A.2 Biogas potential and industrial gas consumption of the different member states

Figure 19 Biogas potential produced from manure as a percentage share of gas consumption per Member State



Source: Frontier Economics based on Scarlat et al (2018) and Eurostat: Gas consumption per Member State based on 2019 data of the nrg_cb_gas series; Biogas potential from manure based on Scarlat et al (2018) 'A spatial analysis of biogas potential from manure in Europe', Table 4 [*https://www.sciencedirect.com/science/article/pii/S1364032118304714#f0010*](https://www.sciencedirect.com/science/article/pii/S1364032118304714#f0010)

Figure 20 Industry gas consumption as a percentage share of total gas consumption per Member State



Source: Frontier Economics based on Eurostat: Gas consumption per Member State based on 2019 data of the nrg_cb_gas series, industry gas consumption based on 2019 data of the nrg_cb_gas__custom_1091113 series

ANNEX B FURTHER INFORMATION ON TOPIC II

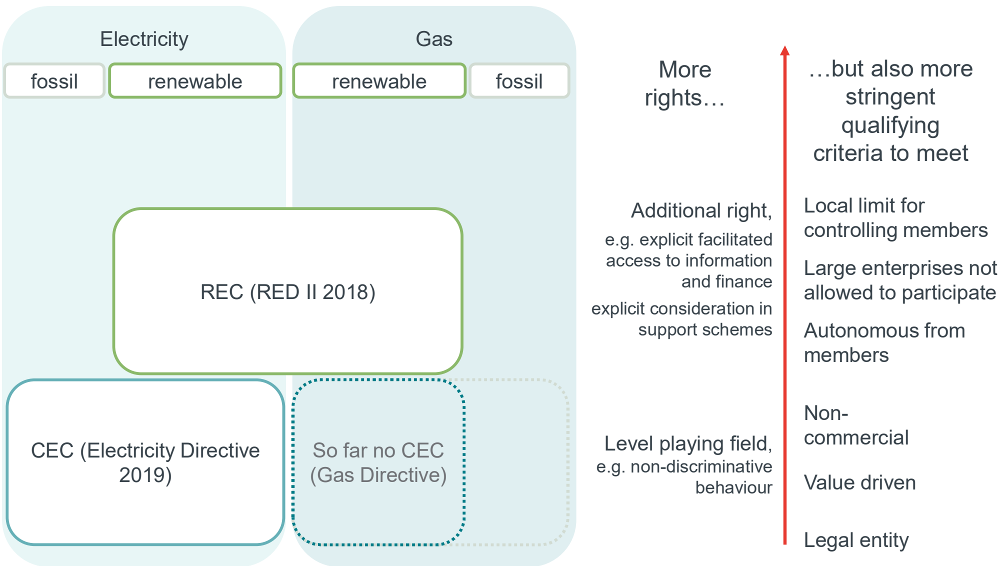
B.1 Energy Communities in the EU legal context

In its Clean Energy for all Europeans package (CEP) the European Commission introduced the goal (among others) of placing the consumer at the heart of the energy transition. In order to ensure that energy communities have more homogeneous possibilities to develop across the EU, the EU legal context has aimed at providing energy communities specific rights (level-playing field engagement and additional rights).

Energy communities are defined in the EU legal context as

- ’renewable energy community’ (REC) in the recast Renewable Energy Directive 2018/2001/EU (RED II) (2018).
- ‘citizen energy community’ (CEC) in Directive 2019/944/EU, “Electricity Directive” (2019)
- There is no concept such as the CEC defined in the gas sector.

Figure 21 Mapping of EU level frameworks for energy communities



Source: Frontier based on RED II and Electrcity Directive

Note: Rights and criteria non-exhaustive

In the following, we summarise their development, similarities and differences.

Renewable Energy Communities (RED II) – a concept for all renewable energy carriers including electricity and gas

Rights for RECs

The EU level regulation (**RED II)** defines Renewable Energy Communities (RECs), energy communities engaged with *renewable* energy. It requires Member States in their national implementation to create a level-playing field and even some additional rights. For example Article 22 requires member states to:

- **Create a level-playing field** for renewable energy communities by ensuring energy communities are not discriminated against, ensure that there are no unjustified regulatory or administrative barriers and that they are subject to fair, proportionate and transparent procedures.
- take some specific steps **to facilitate the development of renewable energy communities**, such as ensuring:
  - tools to facilitate access to finance and information;
  - public authorities are provided regulatory and capacity-building support in enabling RECs; or
  - the specificities of RECs are taken into account when designing support schemes.

Qualifying criteria for RECs

In order to be defined as RECs and therefore be provided the level playing field and some additional rights, the following relatively restrictive criteria have to be met: RECs

- must be active in the *renewable energy* sector
- primary purpose must be to generate social, economic or environmental benefits for the community or for the local areas where it operates
- community must be located geographically close to the renewable energy project
- participation must be open and voluntary; eligible to join are natural persons, local authorities and micro, small and medium-sized enterprises whose participation does not constitute their primary economic activity
- can be effectively controlled by micro, small, and medium-sized enterprises that are located in the proximity of the project
- should be capable of remaining autonomous from individual members or shareholders
- must be recognized as legal entity.

Citizen Energy Communities (Electricity Directive) – a concept only for energy communities concerned with electricity

Rights for CECs

Also the **Electricity Directive** has introduced a definition for energy communities, Citizen Energy Communities (CECs). In contrast to RECs the focus lies not on renewable energy but on electricity – both generated from renewable and fossil sources.

Similarly to RECs, CECs shall benefit from a level-playing field in the electricity market. However, the specific additional rights as defined under RED II are not granted to CECs.

Qualifying criteria for CECs

The criteria that define a CEC are less restrictive than for RECs (which is in line with the fact that fewer rights are assigned for an CEC). It would allow

- for large (energy) enterprises to participate,
- more flexibility in terms of geographical spread of those members or shareholders in effective control; and
- all electricity generation sources.

Comparison of RECs and CECs

Figure 22 Comparison of framework for RECs and CECs

	REC	RED II reference	CEC	Electricity Directive reference	Difference
General characteristics					RECs are more restrictive than CECs
Energy carrier	Renewable energy sector including electricity and gas	Art 22	Electricity – both fossil and renewable „able to access all electricity markets"	Art 16, 3a	
Allowed members	natural persons, micro, small or medium-sized enterprise (SMEs) or local authorities, including municipalities whose participation does not constitute their primary economic activity ("for private undertakings, their participation does not constitute their primary commercial or professional activity")	Art 2, 16b Art 22, 1	"Membership of citizen energy communities should be open to all categories of entities."	Recital (44)	No restriction on size or economic primary activity for members in CECs, while in RECs larger enterprises and are not allowed to participate in RECs
Effective control	micro, small, and medium-sized enterprises that are located in the proximity of the project	Art 2, 16a	"decision- making powers within a citizen energy community should be limited to those members or shareholders that **are not engaged in large-scale commercial activity and for which the energy sector does not constitute a primary area of economic activity**."	Recital (44)	Effective control bound to local proximity for RECs, while for CECs effective control is only limited to members that are not engaged in large-scale activity.
Purpose	"primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits"	Art 2, 16c	"focus primarily on providing affordable energy of a specific kind, such as renewable energy, for their members or shareholders rather than on prioritising profit- making like a traditional electricity undertaking"	Recital (43)	-
Autonomy	remaining autonomous from individual members and other traditional market actors that participate in the community as members or shareholders	Recital (71)	„members or shareholders of a citizen energy community are entitled to leave the community"	Art 16, 1b	Autonomy criteria more explicit for RECs
Activity	"the relevant distribution system operator cooperates with renewable energy communities to facilitate energy transfers within renewable energy communities" „Entitled to „produce, consume, store and sell renewable energy"	Art. 22, 2a	"relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities" "entitled to **own, establish, purchase or lease distribution networks** and to autonomously manage them subject to conditions set out in paragraph 4 of this Article" "the right **to manage distribution networks**"	Art 16, 1d & Art. 16, 2b & 4	Allowance to own and operate distribution grids not explicitly mentioned in RED II, so ambiguous.
Locality	Focus on geographical proximity and local level	Art 2, 16a	No geographical/local limitation „without being in direct physical proximity to the generating installation and without being a single metering point"	Recital (46)	Proximity limitation only in place for RECs
Rules when the system is separated from the system		Art 22, 1, 3, 4a,b,d,e,i	„are subject to the exemptions provided for in Article 38(2)"	Art 16, 3c	Rules applying if the CEC is a separated/closed system are explicitly mentioned in the electricity Directive, while not for RECs in the RED II. However these rules are not specific to them but apply to all separated/closed systems. Therefore, they it can be assumed that Recs will be granted equal rights, once separated.

	REC	RED II reference	CEC	Electricity Directive reference	Difference
Provision of non-discriminatory conditions and level playing field					Both Directives aim to ensure a level-playing field where energy communities can enter and operate on the market facing non-discriminatory conditions.
	On the one hand non-discrimination: „without being subject to unjustified or discriminatory conditions” “unjustified regulatory and administrative barriers to renewable energy communities are removed” “subject to fair, proportionate and transparent procedures” “are not subject to discriminatory treatment” “the equal and non-discriminatory treatment of consumers that participate in the renewable energy community” **On the other hand no exemptions:** “not be exempt from 21.12.2018 L 328/92 Official Journal of the European Union EN relevant costs, charges, levies and taxes that would be borne by final consumers who are not community members, producers in a similar situation, or where public grid infrastructure is used for those transfers”	Art 22, 1, 3, 4a,b,d,e,l Recital (71)	**On the one hand non-discrimination:** “in order to provide them with an enabling framework, fair treatment, a level playing field and a well-defined catalogue of rights and obligations” “are treated in a non-discriminatory and proportionate manner with regard to their activities, rights aggregation, in a non-discriminatory and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation” „subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory […]” **On the other one hand:** “[…]and **cost-reflective** network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they **contribute in an adequate and balanced way to the overall cost sharing of the system.** 14.6.2019 L 158/151 Official Journal of the European Union EN” “are financially **responsible for the imbalances** they cause in the electricity system”	Recital 43 Art 16, 1e Art 16, 3b, c	DG ENER: DG Ener view is that energy communities may be exempt from certain charges. There is some leeway for Member States to do so in light of the principles of non-discrimination, fairness, proportionality and cost-reflectiveness (cf. Article 16 (1) IMED / Article 22 (4) (d) RED II). In fact exemption from transmission system tariffs are being given in countries such as Austria. In DG ENERs view, the lowering of gas quality standards, easing local grid access procedures and introducing exemptions from charges wouldn’t necessarily contradict the Directives, it would rather seem to be a more concrete implementation of these abstract rights pertaining to charges and procedures (with the exception of gas quality standards which are a specific element for gas).
Additional provisions for energy communities					Additional provisions are only in place for RECs, not CECs
Assessment of specific barriers	“assessment of the existing barriers and potential of development of renewable energy communities”	Art 22, 3	“Member States shall ensure that no undue barriers exist within the internal market for electricity as regards market entry, operation and exit, without prejudice to the competence that Member States retain in relation to third countries”	Art 3, 3	Though also the Electricity Directive requires Member States to ensure that there are no undue barriers in Article 3 on „Competitive, consumer-centred, flexible and non-discriminatory electricity markets”, it does not require Member States to explicitly assess barriers for energy communities, thereby positively discriminating them, such as RED II does in Article 22.
Part of national energy and climate plans	„shall be part of the updates of the Member States' integrated national energy and climate plans and progress reports”	Art 22, 5	-		

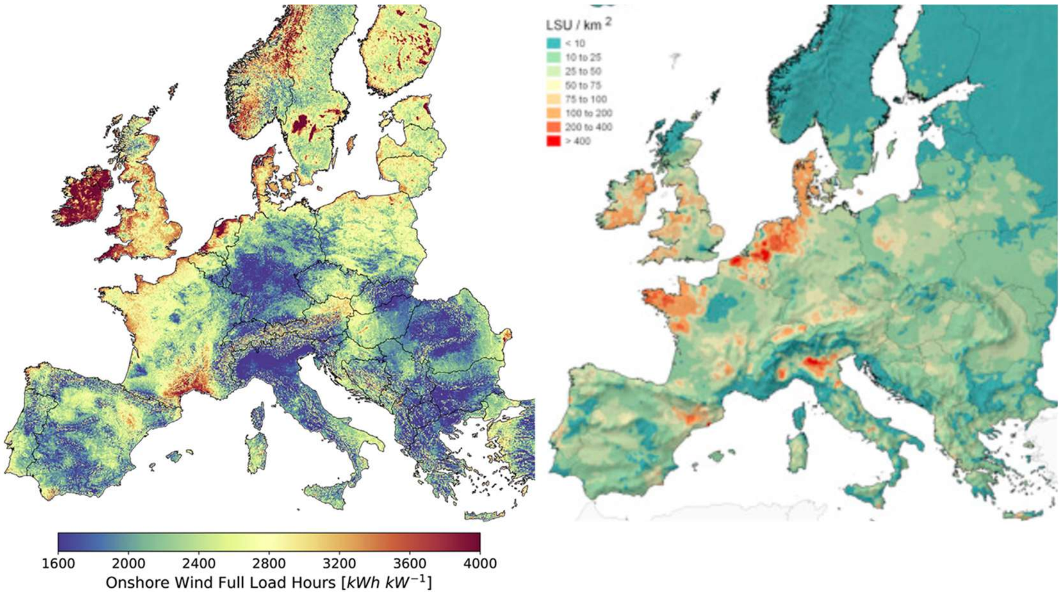
	REC	RED II reference	CEC	Electricity Directive reference	Difference
Support schemes	„ensure that renewable energy communities can participate in available support schemes on an **equal footing with large participants**. Member States should be allowed to take measures, such as **providing information, providing technical and financial support**, **reducing administrative requirements** […] remunerated through direct support” “Member States shall take into account specificities of renewable energy communities when designing support schemes”	Recital (26) Art 22, 7	-		
Increase transparency	„Providing **guidance** to applicants throughout their **administrative permit application** and granting processes by means of an administrative contact point”	Recital (50)	-		
Easy market entry explicitly for energy communities	„to operate in the energy system and easing their market integration”	Recital (71)	-		
Information and access to finance provision	„Member States shall ensure that **information on support measures** is made available to […] renewable energy communities […]” “[…] tools to facilitate access to finance and information are available”	Art 18 Art 22, 4	-		
	„regulatory and capacity-building support is provided to public authorities in enabling and setting up renewable energy communities, and in helping authorities to participate directly”	Art 22, 4	-		

Source: Frontier Economics based on RED II and Electricity Directive

B.2 Geographical distribution of renewable potential

The domestic production potential of gases from renewable and low-carbon sources (such as hydrogen generated from solar, wind or biomass or biogas and biomethane generated from biomass) is geographically distributed (see Figure 23 for the geographical mapping of exemplary renewable energy potential - wind capacity factors [left hand side and biogas potential from manure [right hand side]).

Figure 23 Wind capacity factor and biogas potential from manure spread across Europe

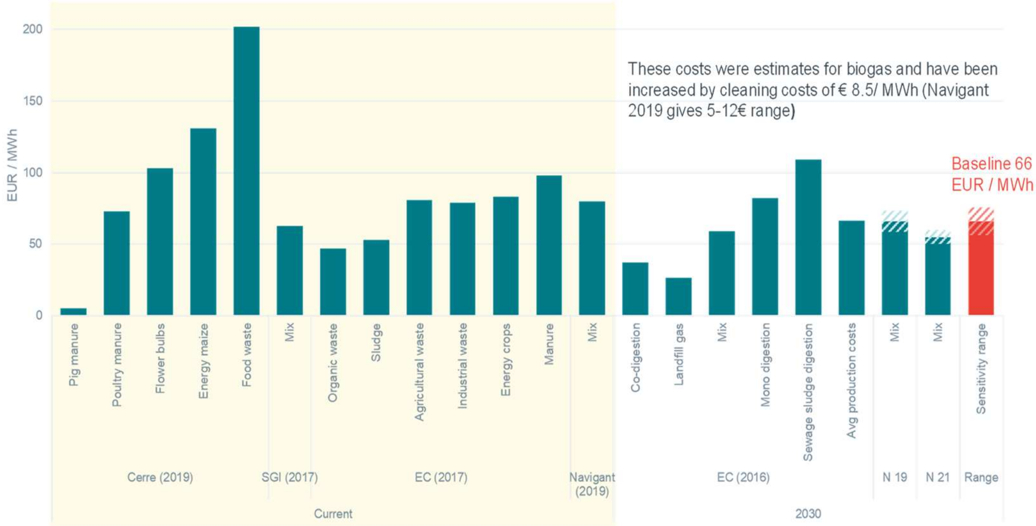


Source: ***Left hand side****: (Ryberg et al., 2019) Average annual wind capacity factor mapped across Europe, not including any consideration of how suitable land is for windfarms)*
Right hand side*: Scarlat et al (2018) 'A spatial analysis of biogas potential from manure in Europe https://www.sciencedirect.com/science/article/pii/S1364032118304714#f0010;*

Note: LSU = livestock units: LSU is "a reference unit, which facilitates the comparison of livestock from various species and ages established on the basis of the nutritional or feed requirement. It is based on the grazing equivalent of one adult dairy cow."

B.3 Background material

Figure 24 Production costs of biomethane in the EU today vs. 2030 split by feedstock



Source: European Commission, 'Optimal use of biogas from waste streams', December 2016; European Commission, 'Building up the future cost of biofuel', March 2017; Navigant, 'Gas for climate', March 2019; CERRE, 'Future markets for renewable gases and hydrogen', September 2018

ANNEX C EXPERIENCES ON THE INJECTION OF ALTERNATIVE GASES OUTSIDE THE EU

This annexe intends to provide some insights into the experience outside the EU on the injection of alternative gases and potential challenges that might come with it. It focuses on the experiences from Great Britain and Australia.

C.1 Great Britain

1) What are the expectations for injections of biomethane/hydrogen at distribution level?

In its report on the UK's sixth Carbon Budget, the UK's Committee on Climate Change (CCC) considered alternative pathways to reaching Net Zero emissions by 2050, including the implications for hydrogen and biomethane.

Hydrogen supply in 2050 ranges between around 150TWh to 350TWh, depending on the scenario, coming from a mix of sources (predominantly electrolysis and from natural gas).[93] In August 2021, the UK Government published a Hydrogen Strategy[94], setting out an ambition of 5GW of low-carbon hydrogen production capacity (42TWh) by 2030. The extent to which hydrogen will be produced and consumed 'off-grid', injected into distribution grids or injected into transmission grids is uncertain.

Biomethane injection is projected to treble by 2030 from today's level in the CCC's Balanced pathway[95], although total biogas production in 2050 ranges between 20TWh to 30TWh across the different pathways considered.[96] Almost all biomethane injection is currently at distribution level (and the majority is expected to be distribution-connected going forwards) but there are ongoing initiatives in place (see below for further details) to make the transmission grid more accessible for alternative gas producers. The support scheme for biomethane injection exposes producers to the market, so producers are already responsible for selling gas (as part of the normal gas trading arrangements).

Overall, there is recognition that the future may see increasing flows of gases from distribution to transmission, and that this may require a change to the current

[93] See CCC (2020) 'The Sixth Carbon Budget: The UK's path to Net Zero', Figure 3.5.h, https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf, accessed 10 September 2021.

[94] https://www.gov.uk/government/publications/uk-hydrogen-strategy

[95] Ibid, p.154.

[96] Ibid, Figure 3.5.j.

framework.[97] However, the precise changes that might be required are still the subject of ongoing research.[98]

2) What steps is the regulator taking (if any) to encourage optimised system planning?

In May 2019, Ofgem decided to take forward three mechanisms to overcome barriers to whole system approaches as part of the current price control period, RIIO-2.

- **Business plan incentive:** Network companies are expected to provide detailed information on their proposals to enable whole system solutions in their Business Plan. Companies may then face a penalty for failing to demonstrate sufficient consideration of whole system thinking, or a reward for demonstrating an ambitious approach.
- **Co-ordinated adjustment mechanism**: This consists of a re-opener for projects which operate across multiple networks and were not identified through the Business Plan process. The re-opener of networks' price control decisions is intended to facilitate more cost-effective outcomes by realigning revenues and responsibilities for projects to be undertaken in the most cost-effective way. The mechanism could be triggered by two (or more) cooperating networks, but a single network could also trigger the mechanism as long as it meets the "threshold requirements" (designed in a way to ensure there is a focus on the most valuable projects with reasonable administrative costs).
- **Whole systems innovation:** Whole system solutions is one of the assessment criterion for innovation funding.

In its RIIO-2 final determinations (for gas and electricity transmission and gas distribution), Ofgem decided that all companies had met the minimum requirements for whole system planning (so there were no penalties imposed through the Business Plan Incentive), but that most plans did not go above and beyond the minimum, and didn't demonstrate a shift in thinking (so neither were any rewards given).[99]

The principles of 'whole systems' extends to coordination between transmission and distribution. It also extends to co-ordination beyond the energy sector, e.g. to transport.[100] (See p. 55-56 here.)

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[97] National Grid (2021) 'A Gas Market Plan research project: 'Implementing the proposed gas quality standards' final report', https://www.nationalgrid.com/uk/gas-transmission/document/135396/download (accessed 7 September 2021).

[98] To be considered as part of the 'Balancing' focus area of National Grid's 'Gas Markets Plan'. See National Grid 'Enabling the Gas Markets Plan 2019/2020', page 5, https://www.nationalgrid.com/uk/gas-transmission/document/132471/download, accessed 7 September 2021.

[99] See https://www.ofgem.gov.uk/sites/default/files/docs/2020/12/final_determinations_-_core_document.pdf, p.114-5.

[100] See https://www.ofgem.gov.uk/sites/default/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_core_30.5.19.pdf, p.55-66.

3) What is the planned approach to dealing with access and connection charging?

Under the existing commercial framework, entry injections at the **NTS** (National Transmission System) level pay the following charges.

- Entry connection charges are based on a 'shallow connection boundary'. That is, the entry connection charges recover the costs of the extension assets, but do not recover any deep reinforcement costs to the network as a result of the user's connection.
- Postage stamp network prices (to be implemented from 1 October 2020) that apply a single price[101] per unit of capacity to all entry points to recover the allowed revenue at entry.[102]

National Grid has run a project looking at ways of simplifying the process (and reducing the cost) of connecting to the transmission system for unconventional and renewable gas producers in particular. According to the project close down report, the project demonstrated that time and cost savings for users are possible through the use of a dedicated "…*software platform, technical standard designs and commercial modifications*".[103]

Entry injections at the **distribution level** pay the following charges under the existing commercial framework.

- Entry connection charges are based on a 'deep connection boundary'. That is, the connection charges recover both costs of the extension assets and some of the deep reinforcement costs to the network as a result of the user's connection.
- A commodity charge which reflects the operational costs associated with the entry of distributed gas directly into the distribution network and some credit elements. The credits reflect:
  - the avoided NTS Exit capacity charge as a result of gas sources not entering the distribution network via the NTS; and
  - the reduced distribution system use if the injection results in lower usage of certain tiers of the distribution system than would be the case had gas entered from the NTS.

In general, renewable and low-carbon gas producers in the UK are required to pay for their connection costs to the grid. They can apply, however, for funding programs that support them financially and, therefore, help them deal with access

[101] The postage stamp price at entry is a reserve price (i.e. the auction floor price for a specific entry/exit point and NTS user). If an NTS user triggers reinforcement costs, it may be required to pay a price above the reserve price.

[102] Ofgem has recently confirmed its decision to move to a postage stamp regime for gas transmission charging, with implementation on 1 October 2020: https://www.ofgem.gov.uk/publications/amendments-gas-transmission-charging-regime-decision-and-final-impact-assessment-unc678abcdefghij

[103] National Grid 'Project CLoCC: Close down report', https://www.nationalgrid.com/uk/gas-transmission/document/127116/download, accessed 10 September 2021.

and connection charging (e.g. 'Low Carbon Hydrogen Supply Competition[104]' and 'Renewable Heat Incentive' (RHI)'[105]).

4) How are expected gas quality issues being addressed?

The Gas Safety (Management) Regulation (GS(M)R) governs gas quality standards in the UK, with individual connection agreements specifying limits on injection gas quality. National Grid (the GB TSO) monitors gas quality at all entry points and can curtail flows to prevent off-specification gas from reaching the transmission system.[106] This in turn can create a liability for shippers (as it means that they may have a shortfall of gas on their entry portfolio), which may incentivise them to contract for gas supplies that comply with quality standards.

There is ongoing work[107] considering how gas quality standards might need to evolve in the future given expected increases in the amount of biomethane and hydrogen on the system.[108]

National Grid, the GB Gas TSO, has published a report considering how market arrangements may need to change to accommodate possible changes in the gas quality ranges permitted by UK legislation and outlining possible areas for further work.[109] Short-term recommendations include improved support/guidance for users seeking to make changes to their connection agreements and improved transparency (by standardising/centralising the publishing of gas quality parameters/limits). Longer-term recommendations related in the event of possible future hydrogen blending include developing greater visibility on the gas quality needs of different users and a need to develop solutions for managing the possibly diverging interests of hydrogen producers and end-users.

As part of work commissioned by Cadent Gas (a gas distributor) through Network Innovation Allowance (NIA) funding, Frontier considered how the GB gas commercial framework (for example in respect of system operation and connections) might need to evolve to facilitate hydrogen blends of up to 20% by volume. Our report concludes that the existing commercial framework can remain mostly intact, including energy trading and balancing arrangements. Only a limited number of changes need to take place to enable hydrogen blending, particularly under "baseline" circumstances, when there will be a relatively small number of (fairly dispersed) hydrogen injection points.[110]

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104 https://www.gov.uk/government/publications/low-carbon-hydrogen-supply-2-competition

105 https://www.ofgem.gov.uk/environmental-and-social-schemes/domestic-renewable-heat-incentive-domestic-rhi/contacts-guidance-and-resources/tariffs-and-payments-domestic-rhi

106 National Grid (2020) 'GMaP Gas Quality Knowledge Share', https://www.nationalgrid.com/uk/gas-transmission/document/135401/download, accessed 7 September 2021.

107 See, for example: https://www.igem.org.uk/technical-services/gas-quality-working-group/

108 Currently, GS(M)R only allows 0.1% of hydrogen within the gas mix (unless an exemption is granted from the Health and Safety Executive).

109 National Grid (2021) 'A Gas Market Plan research project: 'Implementing the proposed gas quality standards' final report'

110 Frontier Economics (2020) 'Hydrogen blending and the gas commercial framework: Report on conclusions of NIA study", available at: https://www.frontier-economics.com/media/4201/hydrogen-blending-commercial-framework.pdf

C.2 Australia[111]

1) What are the expectations for injections of biomethane/hydrogen at distribution level?

Overall, while the gas industry is keen to promote renewable and low-carbon gases (including a renewable gas target), Australia seems to be leaning towards a focus on electrification.

- Due to its climatic conditions, Australia is well-suited to solar PV generation (including at small-scale), and there is a broad coalition of stakeholders pushing for electrification.
- There are suggestions (e.g. as part of the ongoing policy review in Victoria state) that measures might be brought in to prevent new gas connections (the New Zealand Climate Change Commission has similarly recommended a phase out of gas[112]).
- The regulator is considering whether there is a need to accelerate the depreciation of gas infrastructure assets, given the expected decline in gas demand.

However, some analysis (such as a recent study by Frontier Economics Pty[113]) suggests the costs of the energy transition may be reduced by maintaining the use of gas infrastructure. It may be that the challenges that reliance on electrification alone will bring to the system (e.g. in terms of required grid upgrades) are not yet widely appreciated.

There is significant **biogas** potential in Australia. However, biomethane injection is nearly non-existent today, with most biogas (mostly from landfill or sewage treatment facilities) being flared, but with a sizeable minority being burned for heat and/or electricity. Given farms are typically located far away from population centres (where gas networks are present), it is unclear whether biomethane injection will take place at large scale. In addition, the expectation is that biomethane will (in the absence of support) be more expensive than natural gas (even at currently high natural gas prices), though there is significant uncertainty as biomethane is still yet to be developed at any scale.

One trial project for biomethane injection (a collaboration between Sydney Water and the local gas DSO) is underway (with 50% of funding from the Australian authorities) and is due to be operating Q1 2022. The gas injected will be required to meet existing technical specifications.

There are also plans to develop clean **hydrogen**. However, these plans are longer-term and mostly focussed on exporting hydrogen directly, or clean hydrogen based ammonia, or clean hydrogen-based “green steel” (or other heavy industry

[111] Note: the section on Australia is a summary of a discussion with Andrew Harpham, Director at Frontier Economics Pty in Sydney, Australia, held 15 September 2021

[112] See, for example, https://www.nzherald.co.nz/nz/climate-change-report-whats-the-future-of-gas/YYQ4KMX3Q3EFALSD4XM35I45VU/, accessed 16 September 2021.

[113] Frontier Economics (2020), ‘The benefits of gas infrastructure to decarbonise Australia: A report for the Australian gas industry”, https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/the-benefits-of-gas-infrastructure-to-decarbonise-australia-frontier-economics/

products).. Hydrogen production is expected to mainly be utility scale, outside cities (i.e. away from gas distribution grids).

2) What steps is the regulator taking (if any) to encourage optimised system planning (across gas transmission and distribution)?

The regulator is not considering this.

3) What is the planned approach to dealing with access and connection charging?

So far, there has not been much thinking on this issue, given that injection of gases at distribution level is still at an early stage. Currently, a ‘shallow’ connection charging regime is in place for both gas and electricity.

4) How are expected gas quality issues being addressed?

As above, there has been little thinking on this issue and so far the injected gas needs to be within approved gas quality specifications to be injected.

5) Is there interest in (citizen-led) “energy communities” and if so, how is decarbonised gas production at energy community level being facilitated?

Energy communities so far only exist for electricity. Where they do exist, their focus tends to be on encouraging further electrification.

6) What plans are in place for gas smart meter roll out? What is the basis for these plans?

There are no plans for gas smart meter roll-out at the moment. The current focus is on electricity smart meter roll-out.

Given climatic conditions in Australia, gas consumption (per capita) for heating is typically small and restricted mainly to peak times. This means there may be a smaller energy efficiency benefit from installing gas smart meters, compared to regions such as North West Europe, with higher per capita gas consumption for heating.[114]

In addition, stakeholders are likely to resist a gas smart meter roll-out in Australia:

- Network operators’ preferred approach for recovering fixed charges is a declining block (variable) tariff. This means that (beyond a minimum use for cooking and water heating), users face a lower variable network charge for using gas, which may incentivise them to adopt gas heating. To the extent that any smart meter roll-out might lead to a push for a more cost-reflective network charging arrangement that might place cost recovery for DSOs under threat, DSOs might resist it.

[114] Although the picture does vary by location in Australia. For example, in Melbourne average annual households gas consumption is roughly 50 GJ (while the respective figures for Sydney and Brisbane are roughly 20 GJ and 10 GJ).

- In addition, there is low political appetite for smart meter roll-out. Victoria state started its electricity smart meter roll out 10 years ago. Following a consumer backlash, legislation was introduced against time of use pricing.

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Publications Office
of the European Union

ISBN 978-92-76-51629-3