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Centre on Regulation in Europe

REPORT

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FUTURE MARKETS FOR RENEWABLE GASES & HYDROGEN

**WHAT WOULD BE THE OPTIMAL
REGULATORY PROVISIONS?**





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Executive summary

This report explores the economic outlook for renewable gases and hydrogen and proposes a regulatory framework for them. The report first analyses the technologies for the production of these gases, their associated costs and their potential future supply for a selection of European countries. Then, the study puts forward an array of regulatory measures for the markets for these gases.

The present production costs of the various renewable gases and hydrogen range from 2 to 5 times the current price of natural gas in the wholesale market. This implies that in the absence of support, renewable gases and hydrogen will find it difficult to enter the market.

The potential supply of renewable gases from anaerobic digestion and gasification is estimated at around 75 bcm per year for the selected countries (BE, DE, FR, GE, IT, NL and UK), and 124 bcm per year for the EU-28. According to Navigant (2019), the supply of renewable electricity-sourced hydrogen from excess electricity in Europe could reach 18 bcm by 2050; this potential could be much higher using dedicated wind and solar resources as well as electricity imports from regions outside the European Union, potentially meeting the entirety of estimated demand for hydrogen in Europe (1710 TWh). The potential supply of this type of hydrogen depends heavily on the future development of renewable electricity on the one hand and the evolution of the demand for electricity on the other hand. The maximum supply of natural gas-sourced H₂ mainly depends on the availability of CO₂ storage and in particular the social acceptance of it.

The economic regulation of renewable gases and hydrogen is meant to improve their position in the market for gas, on the basis that their unfavourable position is due to market failures. This report develops an analytical framework to define the optimal set of regulations. Drawing from this framework, it suggests targets for renewable gas and hydrogen and proposes certificates schemes, access conditions for the grid and, finally, support schemes.

Departing from the assessment of the potential supply of renewable gases and hydrogen, as well as scenarios regarding the future consumption of gas, the report recommends setting the target share of renewables gases in total gas consumption at 10-12% for 2030 and 20-50% for 2050. Conditional on the social acceptance of CCS, the target for hydrogen should be 100% of carbon-neutral hydrogen by 2050.

In order to further improve the current certification system, the report recommends increased integration of national systems by setting EU standards for renewable gases, making Guarantees of Origin certificate systems interchangeable and ensuring compatibility with the ETS. In addition, the role of public authorities in the certification process should be enhanced in order to improve the trust of market parties in the system. Moreover, the report recommends evaluating the pros (transparency) and cons (market liquidity) of the current mass-balancing approach which is used in the international trade of GOs.

When it comes to the conditions for using the gas grid, the same economic principles should be used for renewable gas as for natural gas in order to enhance an efficient use of the grid. In case of (local) congestion, renewable gas may, however, be given priority in order to ensure network access.

Due to the presence of negative externalities in the use of natural gas, there is a clear economic rationale to support producers of renewable gas and hydrogen. The maximum value of this support is determined, on the one hand, by the value of this negative externality and, on the other, the value of other regulatory measures to internalise the externality. Using this principle, the support



for renewable gas or hydrogen should, at a maximum, be 50 (100) €/MWh when the negative externality of CO₂ emissions is estimated at 100 (200) €/ton of CO₂ (provided that the producers do not receive any other support). If this maximum value exceeds the additional costs of bio-methane and hydrogen compared to natural gas, the optimal support level should be determined by the additional costs.

1. Introduction

1.1. Background

The future role of the gas industry has come into focus in light of the ambitious EU decarbonisation targets for 2050 and the very low price of carbon. Many questions are raised about the future position of gas in a sustainable future. A consensus seems to be emerging that, in the short run, natural gas will play an important role as a substitute for coal and nuclear in baseload generation, as well as a source of flexibility in electricity systems. What remains to be seen is whether gas will keep a significant position in the long-term future energy mix. For this purpose, the gas industry necessarily has to decarbonise itself.

Renewable gases, such as biogas and bio-methane, and hydrogen are developing. Their importance is expected to grow in the future, supporting decarbonisation in various sectors of the economy, in particular in the electricity and heating sectors. A gradual increase in the share of renewable gases and hydrogen is regarded as key to the sustained use of the existing gas infrastructure in the future. Sector coupling between electricity and gas (and also heat) has been discussed for decades but it is now highlighted, especially in relation to power-to-gas.

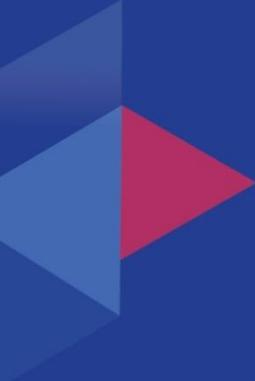
1.2. Research questions

Against the above background, this Project's main research questions are as follows:

- What is the status quo development of renewable gases? What is its potential within Europe? What will likely be the development of the supply of renewable gases?
- What are the market failures hampering the development of renewable gases and hydrogen (cost disadvantage, asymmetric information, hold-up, gas quality, network externalities, market power, etc.)? Are there regulatory barriers to the development of these gases?
- How can these new gases be encouraged if the market does not develop in line with society's welfare gains from pollution abatement? What could be the nature of efficient incentive schemes: investment support, feed-in tariffs, green certificates, tax breaks, etc.?
- How can the existing gas infrastructure be used most efficiently to facilitate increasingly higher quantities of renewable gases and hydrogen? Should the existing regulatory provisions be amended?

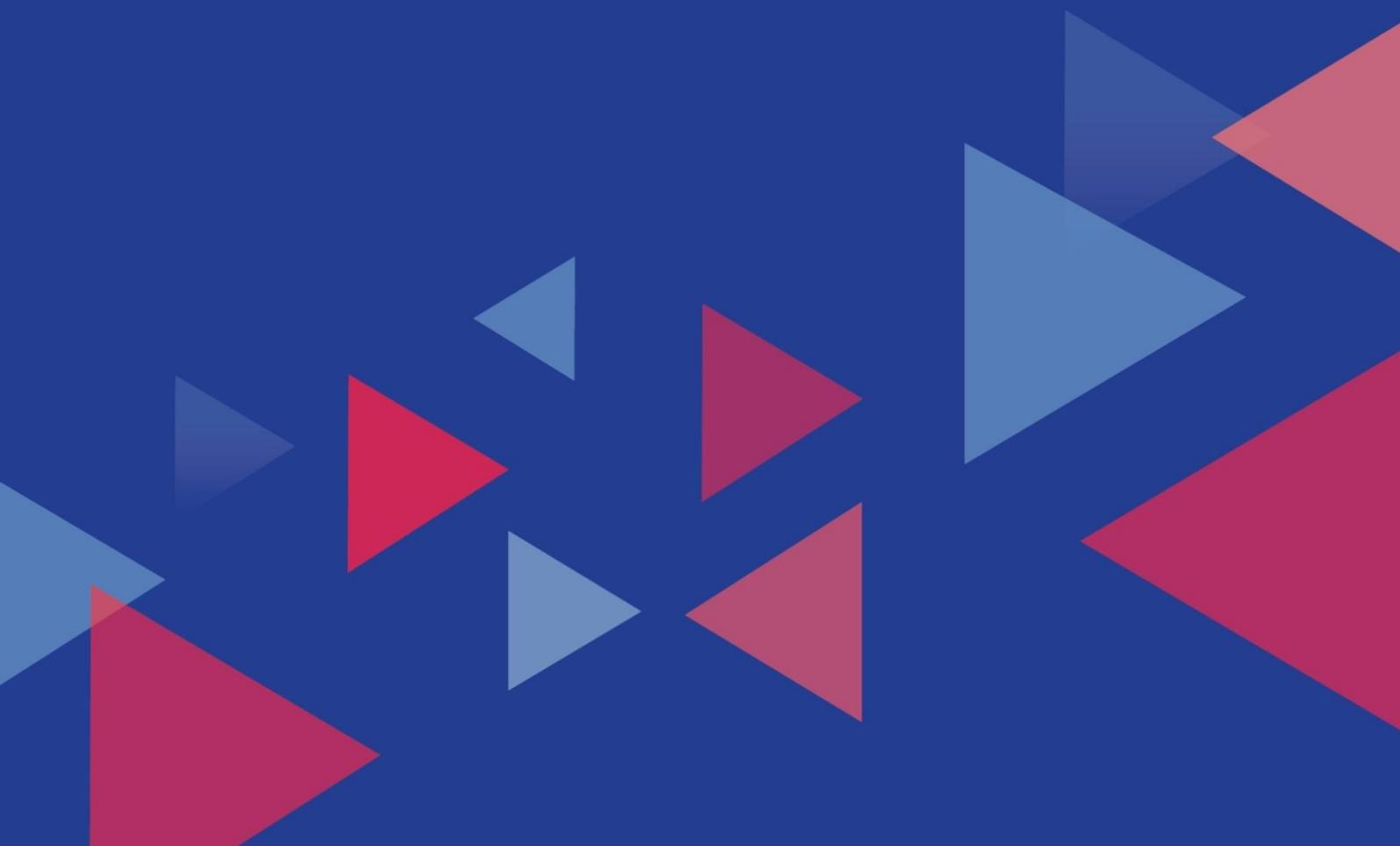
1.3. Outline of the report

The structure of this report is as follows. In Part I, we explore the existing processes for the production of renewable gases and hydrogen; we also investigate the current and potential supply of renewable gas and hydrogen by production technology. In Part II, we present the economic principles that should guide the regulation of the markets for renewable gases and hydrogen and describe the existing regulations in some European countries. Assessing the best practices and most efficient measures, we draw recommendations for an EU-wide approach to regulation of these markets.



PART 1

COSTS AND SUPPLY



2. Technologies for the production of renewable gases and hydrogen

2.1. Introduction

The prominence of renewable gases and hydrogen in the future energy mix is a common feature in existing reports on the global outlook of the gas industry (see e.g. GasUnie & Tennet, 2019; Navigant, 2019). These reports, however, use the term 'green gases' as an overarching term that incorporates several types of gases. Therefore, before proceeding further, it is important to first clarify what the terminology in this report will be and how it compares to the terminology used in the related literature. We do this in Box 2.1 below.

In this report, we evaluate four different gases, produced from distinct production processes each with its associated range of feedstocks. These different types of gases are presented and described in Section 2.2. Then, in Sections 2.3, 2.4 and 2.5, we investigate the production processes and the costs involved in the supply of each of these four gases. Our costs estimates are based on the existing literature, which we report later in detail; we note that these estimates vary from source to source.

Box 2.1 Terminology used in this report

In the existing literature on green gases, there is a wide variety of terms used. In order to keep the report consistent, we make use of a uniform terminology throughout.

When the renewable gas is produced through the anaerobic digestion of biodegradable materials, we refer to it as **biogas**. Biogas is not a standardised gas, so its energy content varies across production sites. When the biogas is upgraded to a standardised specification that can directly be injected into the natural gas grid, we speak of **bio-methane**.

When the renewable gas is produced via thermal gasification, the same holds. The difference is that with this technology the biogas is upgraded to bio-methane during the production process. Therefore, bio-methane is the only output of thermal gasification.

In some reports, the term 'green gas' is commonly used for a gaseous mix that has properties (heating value, Wobbe-index and density) similar to those of the natural gas that is currently used in Europe. Green refers to the fact that the gas is carbon-neutral or carbon-negative. We will abstain from using the term green gas here.

Concerning **hydrogen** production, this study will refrain from using 'colours' to categorise types of hydrogen and, in turn, will opt for a more precise terminology. We will distinguish among hydrogen produced from natural gas combined with Carbon Capture and Storage (CCS) and hydrogen produced from renewable electricity. We will refer to the first type of hydrogen as **natural gas-sourced hydrogen** and to the second as **renewable electricity-sourced hydrogen**. Sometimes, we will shorten the concepts as **NG-sourced H₂** and **RE-sourced H₂**.

Other studies speak of 'blue hydrogen' when they consider NG-sourced H₂ and of 'green hydrogen' to refer to RE-sourced H₂. There is also the notion of 'grey hydrogen', which alludes to hydrogen sourced from natural gas without CCS. We will not study this type of hydrogen here.

In addition, note that hydrogen from renewable electricity can also be upgraded to meet the specification of natural gas through a methanation process. We refer to the resulting gas as ***methane from renewable electricity-sourced hydrogen***.

2.2. Types of gases

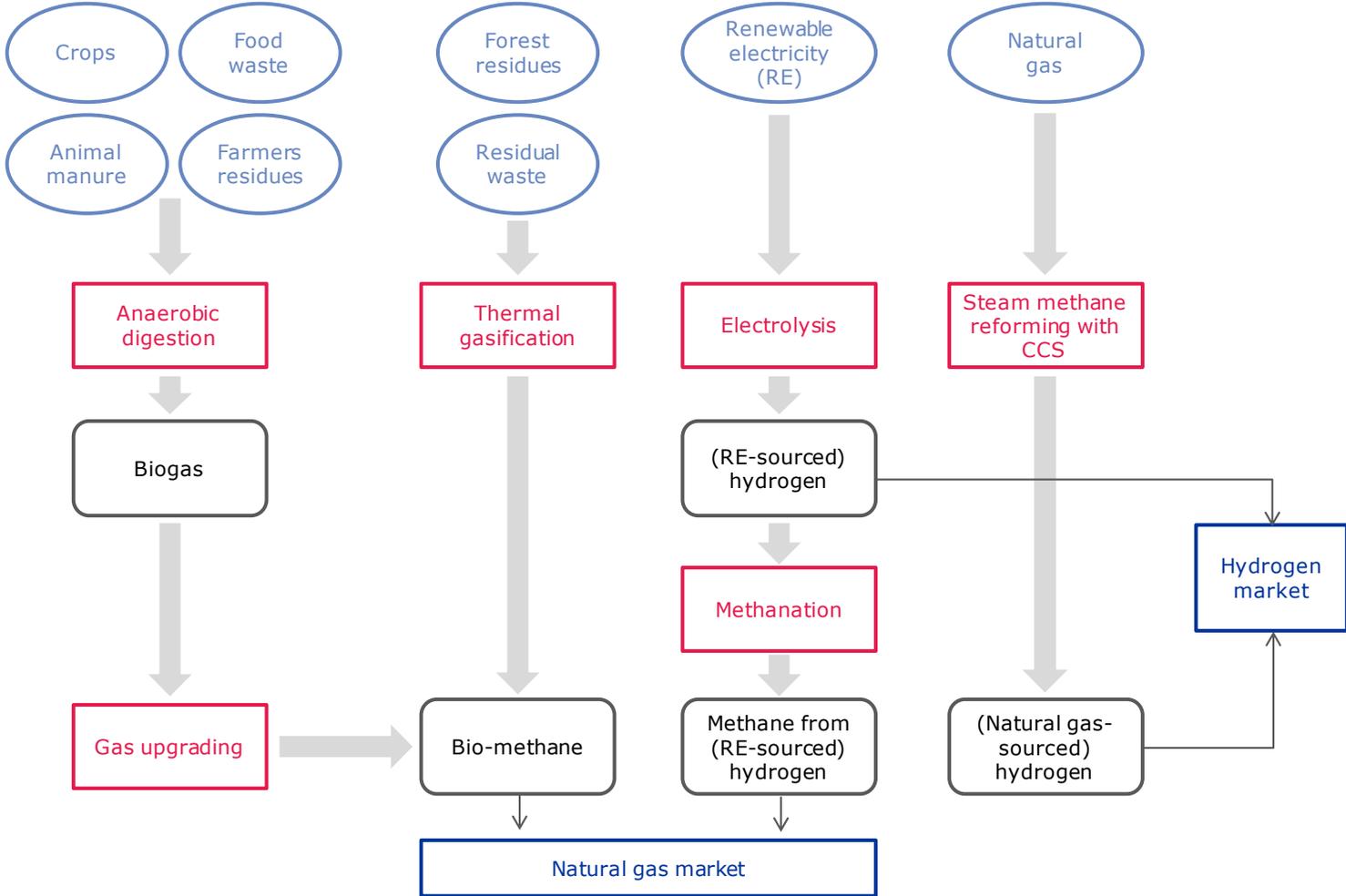
As explained in Box 2.1, there are various names used to refer to the different types of renewable gases and hydrogen. The gases we analyse in our report are:

- **Biogas**
 - produced through anaerobic digestion
- **Bio-methane**
 - produced through thermal gasification
 - or after the purification of biogas
- **Hydrogen**
 - produced from natural gas using CCS
 - produced from the electrolysis of water using renewable electricity
- **Methane from hydrogen**
 - produced after methanation of renewable electricity-sourced hydrogen.

Figure 2.1 provides a schematic overview of the different gases and their production technologies. Bio-methane and methane from hydrogen refer to a mixture of gases that has the same qualities as natural gas and can be injected into the gas network.¹ The only difference with natural gas is the origin of the gas, hence the alternative name. Biogas has a lower methane content per cubic meter (m³) of gas and therefore a lower heating value. Transporting biogas cannot be done in natural gas pipelines, since the mixture is different. Hydrogen is a different kind of product; its heating value is not determined by the methane content, but by the purity of the hydrogen. Hydrogen can directly be injected into the natural gas grid or transported by separate pipelines or trucks. There is an ongoing debate about how much hydrogen can directly be injected into the natural gas grid without compromising the properties of the gas mix and the safety of the network. As this debate is not yet settled, in this report we do not consider this possibility. The best way to transport hydrogen is mainly determined by quantity and distance (Mulder et al., 2019).

¹ A heating value of 9.77 kWh/m³.

Figure 2.1: Schematic overview supply chain renewable gases and hydrogen²



Source: Authors' own elaboration

² Note that although it is technically possible to inject hydrogen in the natural gas grid, we do not consider this option in this report. As we explain later, the reason for this choice is that, as far as we know, the debate about how much hydrogen can be injected into the grid is not yet settled.



In what follows, we investigate the economic outlook of each of these products and their production processes. In order to do this, we calculate the minimum remuneration for the gas produced that is needed to make the corresponding technology profitable. This minimum price is the financial compensation needed to cover both the fixed (CAPEX) and variable costs (OPEX) over the lifetime of the production plants. The fixed costs relate to the investment costs per unit of capacity, the number of gas units produced with one unit of capacity and the lifespan of a plant. The variable costs are the marginal costs of producing and can be measured in costs per unit produced. The combined fixed and variable costs of a technology of gas production constitute a threshold remuneration above which the technology is profitable (see Box 2.2).

Box 2.2 Calculation of the break-even price for bio-methane and hydrogen

In analysing the different production technologies for hydrogen and bio-methane, it is important to have a uniform measure of the costs involved. Since both are used for energy consumption, we calculate all the associated costs in terms of € per Megawatt hour (€/MWh). We distinguish two different types of costs: investment costs (e.g. construction of plant, construction of pipelines, fixed maintenance costs) and variable costs. To express the investment costs in costs per production unit (MWh), we take the present value of all investment costs and divide it by the discounted production of the plant during its total lifespan. This part of the costs is referred to as the capital expenditures (CAPEX). For the unit variable costs, or operational expenditures (OPEX), we sum all the costs per unit of production. Finally, we add the CAPEX and OPEX to find the minimum output price in €/MWh for a given production process to be profitable. If the market price of the energy produced with a given technology exceeds this minimal required price, the NPV of the investment decision for such a process is positive.

2.3. Anaerobic digestion

2.3.1. Production process

The production of biogas through anaerobic digestion is a process by which biodegradable material is broken down by microorganisms. Anaerobic digestion is typically used to manage waste, sewage sludge and manure and so reduce emissions of landfill gas, which has an important influence on climate change. The bulk of the production of biogas uses feedstock from waste; however, anaerobic digesters can also be fed with crops specially grown for this purpose (e.g. 'energy maize'). The product of anaerobic digestion is biogas, which is a mixture of methane, carbon dioxide, hydrogen, ammonia and other substances (Molino et al., 2013). This mixture is used as a source of renewable energy, either directly as an input in combined heat and power units, or after upgrading it to bio-methane.

Nowadays, there are a number of technologies commercially available that can upgrade biogas to bio-methane that can directly be injected into natural gas grids (Vienna University of Technology, 2012). The upgrading of biogas to bio-methane is a process involving gas separation, compression and odorisation. Upgrading requires the drying of the gas, separation of carbon dioxide, removal of substances such as nitrogen, ammonia, oxygen or hydrogen sulphide as well as the compression to a desired pressure. For injecting the gas into natural gas grids, the gas often has to be odorised (this depends on the country). In this paper we analyse 4 different technologies; pressurised water scrubbing, pressure swing adsorption, membrane separation and amine scrubbing.

As mentioned above, a quite substantial part of the production of biogas uses feedstock stemming from waste management. Due to its characteristics (low percentage of dry matter and quick emission of landfill gas) these inputs cannot be transported over long distances. A typical assumption is a range between 10 and 50 km (Scarlat et al., 2018). Therefore, the production of biogas is often done locally, and at a small scale, on farms.

2.3.2. Production costs

As explained above, the costs of bio-methane produced through the anaerobic digestion of biodegradable material relate to two processes, namely, biogas production and upgrading of biogas to bio-methane. The data and assumptions used for estimating the costs of biogas production and the upgrading to bio-methane are given in Tables 2.1 and 2.2, respectively.

Table 2.1 Assumptions on the costs of producing biogas through anaerobic digestion

Assumptions	Value	Source
Production capacity (MW)	1.4	SgROI et al. (2015); Cucchiella et al. (2015); Carlini et al. (2017); Gebrezgabher et al. (2010)
lifetime plant (years)	20	Cucchiella et al. (2015); Gebrezgabher et al. (2010)
Operating hours	7884	Cucchiella et al. (2015); Gebrezgabher et al. (2010); DEA (1995)
CAPEX (€/MWh)	38.4	SgROI et al. (2015); Cucchiella et al. (2015); Carlini et al. (2017); Gebrezgabher et al. (2010)
Electricity input (kWh/kWh biogas)	0.03	Bortoluzzi et al. (2014)
Electricity price (€/MWh)	50	Bloomberg
Other OPEX (€/MWh)	34.5	SgROI et al. (2015); Gebrezgabher et al. (2010); Stürmer et al. (2015)
Feedstock costs (€/MWh)	variable	Gebrezgabher et al. (2010)

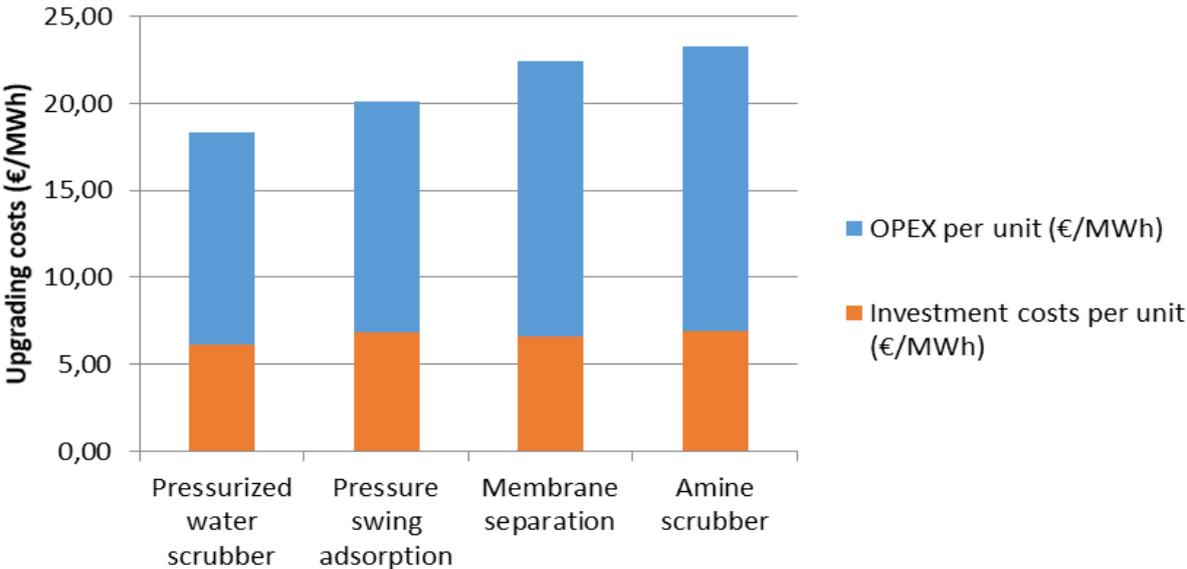
Table 2.2 Assumptions on the costs of upgrading technologies of biogas

Assumptions	Value	Source
Investment costs (€)		
Pressurised water scrubber	2794000	Stürmer et al. (2015)
Pressure swing adsorption	3140000	idem
Membrane separation	3033000	idem
Amine scrubber	3166000	idem
Operational costs (€/a)		
Pressurised water scrubber	513000	idem
Pressure swing adsorption	557000	idem
Membrane separation	662000	idem
Amine scrubber	688000	idem

As shown in Figure 2.2, the cost of upgrading biogas to bio-methane is fairly similar for the 4 different technologies that are usually employed. All the different technologies show economies of scale: an increase in capacity lowers the unit cost since significant investment expenditures can be divided over more units of output (Stürmer et al., 2015). The costs depicted in the graph represent unit costs for a production capacity of roughly 5 MW.³ For all upgrading technologies, the investment costs are around 20 €/MWh and make up to approximately 1/3 of the total costs.

The total costs of production of bio-methane from AD are highly dependent on local feedstock costs and these costs vary significantly across regions. Figure 2.3 shows the estimated production costs of bio-methane through anaerobic digestion for the case of the Netherlands. Excluding the feedstock costs, the unit costs of production are estimated to be around 100 €/MWh. In addition, the Figure shows the feedstock costs for the production of one unit of bio-methane in the Netherlands (Gebrezgabher et al., 2010). As can be seen, feedstock costs for animal manure are negative due to the fact that biogas plants are paid by farmers for collecting it. In the Netherlands, manure market prices are relatively stable over time with an average price of approximately 23 €/ton of manure.

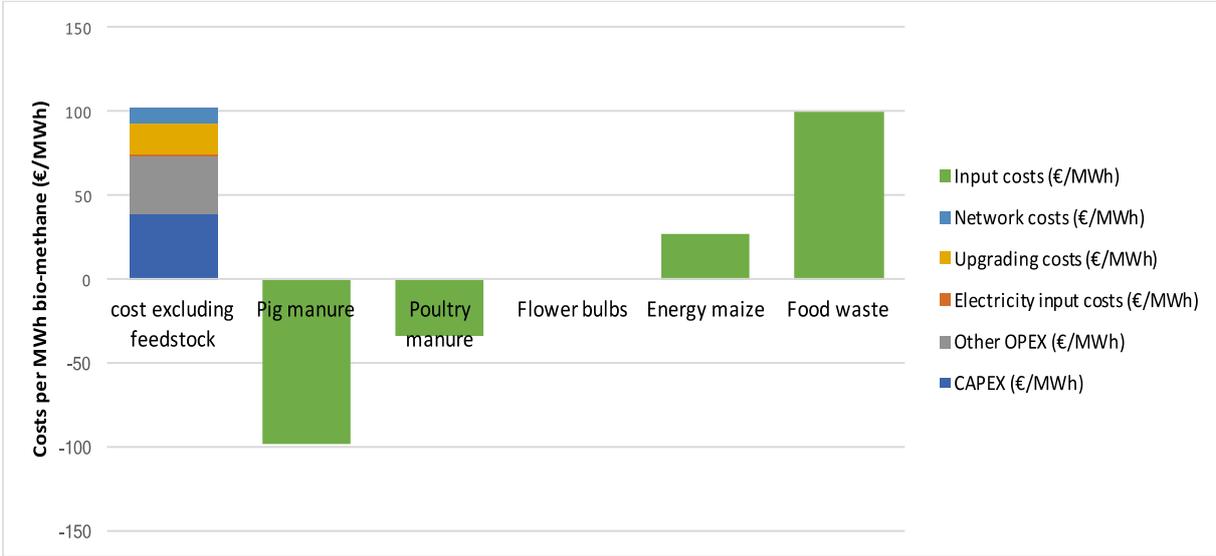
Figure 2.2 Purification technologies and their costs



Source: Authors' own elaboration. Data stem from Stürmer et al. (2015)

³ This corresponds to approximately 500 Nm³/hour.

Figure 2.3 Composition of the costs of anaerobic digestion and feedstock costs, per MWh



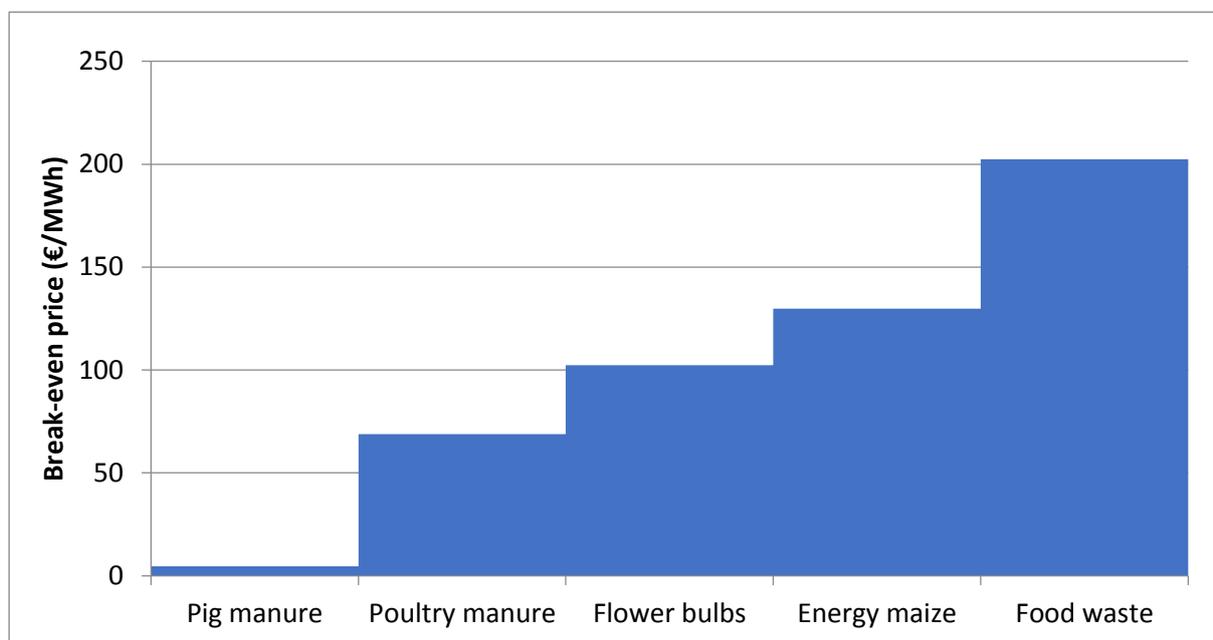
Source: Authors' own elaboration. Data stem from the sources in Table 2.1

Combining the production costs with the costs of a specific feedstock yields a merit order for the production of bio-methane through anaerobic digestion and purification. This merit order is depicted in Figure 2.4. The break-even price for bio-methane from AD ranges from 5 to 200 €/MWh. Note, however, that in many anaerobic digesters, a combination of different feedstocks is used, therefore the range will in practice be smaller. The optimal combination of feedstocks is not clear-cut, since it also depends on the bacteria used in the production process (SgROI et al., 2015). Furthermore, even if an optimal combination of feedstocks exists, the optimal feedstock mix may not be available in the vicinity of the production plant, in which case relatively large costs should be added.

For other countries, cost estimates are similar. Data from ENEA (2018) reveal unit costs ranging from 85 to 122 €/MWh for the case of France. The Italian *Consorzio Italiano Biogas* reports a best-practice cost estimate of 75 €/MWh before injection into the grid (CIB, 2017). The Navigant study (2019) gives a cost-range of 70-90 €/MWh.

Altogether, it is clear that the cost of bio-methane varies substantially across countries and projects. However, the costs are generally higher than the current natural gas price.

Figure 2.4 Break-even price for bio-methane from anaerobic digestion, in the Netherlands, per type of feedstock, per MWh



Source: Authors' own elaboration. Data stem from the sources in Table 2.1

2.4. Thermal gasification

2.4.1. Production process

Thermal gasification is a partial oxidation⁴ process that converts biomass into a gaseous mix consisting of hydrogen, carbon monoxide, methane and carbon dioxide. Like natural gas (Rodrigues et al., 2003), this mix can be used to generate heat and power. Also, it can synthesise other chemicals and liquid fuels, or produce hydrogen (Rapagna et al., 2002). Furthermore, after methanation of the carbon monoxide and dioxide and gas cleaning, bio-methane can be produced that meets the gas quality standards of the natural gas grid and can therefore be directly injected into it.

In contrast to anaerobic digestion, the process of thermal gasification is done on a much larger scale. Typical plant sizes are close to 200 MW of output capacity, but production capacities are expected to be scaled up to 1000 MW in the near future (Batidzirai et al., 2019). Due to this increase in scale, it is economical to incorporate the upgrading process of the gaseous mix to bio-methane in the thermal gasification facility. Hence, in what follows, we assume that the whole process of transforming biomass into bio-methane via thermal gasification, methanation and cleaning is done in the same facility.

The inputs used in thermal gasification processes are different from those used in anaerobic digestion ones. Typically, the biomass inputs used in thermal gasification are forestry products and residual wastes. This process uses less moisture biomass inputs compared to anaerobic digestion, because there is no need to keep bacteria alive. This increases the methane yield of the biomass input mix significantly, which in turn allows the feedstock for thermal gasification to be imported

⁴ Partial oxidation is a chemical reaction that occurs when a fuel-air mixture is partially combusted in a reformer, creating a hydrogen-rich syngas.

from larger distances. The only serious constraints on production are then the costs of feedstocks and feedstock transportation.

2.4.2. Production costs

The data and assumptions used for the estimation of the costs for the production of bio-methane from thermal gasification can be found in Table 2.3.

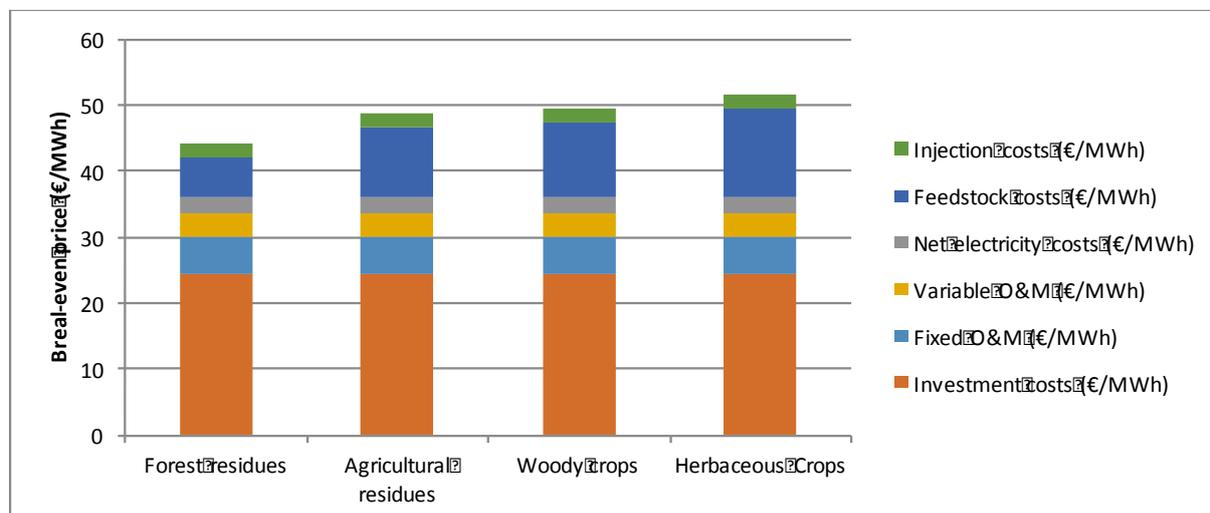
Table 2.3 Assumptions on the costs of producing bio-methane through thermal gasification

Assumptions	Value	Source
Production capacity (MW)	187.47	Holmgren (2015); Möller et al. (2013a); Möller et al. (2013b); Tuna & Hulteberg (2014); Heyne & Harvey (2014); Gassner & Marechal (2012)
lifetime plant (years)	20	Holmgren (2015); Möller et al. (2013a); Möller et al. (2013b); Tuna & Hulteberg (2014); Heyne & Harvey (2014); Gassner & Marechal (2012)
Operating hours	7884	Holmgren (2015); Möller et al. (2013a); Möller et al. (2013b); Tuna & Hulteberg (2014); Heyne & Harvey (2014); Gassner & Marechal (2012)
CAPEX (million €)	470.6	Holmgren (2015); Möller et al. (2013a); Möller et al. (2013b); Tuna & Hulteberg (2014); Heyne & Harvey (2014); Gassner & Marechal (2012)
Electricity input (kWh/kWh biogas)	0.05	Holmgren (2015); Möller et al. (2013a); Möller et al. (2013b); Tuna & Hulteberg (2014); Heyne & Harvey (2014); Gassner & Marechal (2012)
Electricity price (€/MWh)	50	Bloomberg
Fixed O&M (€/MWh)	5.71	IRENA (2012)
Variable O&M (€/MWh)	3.45	IRENA (2012)
Injection costs (€/MWh)	2.00	Navigant (2019)
Feedstock costs (€/MWh)	Variable	IRENA (2012), Smekens et al. (2017), Penn State College of Agricultural Sciences

Figure 2.5 gives an overview of the thermal gasification costs per unit of bio-methane. The total production costs range from 44 - 52 €/MWh, of which more than a half are investment costs. Compared to anaerobic digestion, the bulk of the cost difference is the significantly lower operating and maintenance (O&M) costs, due to economies of scale. Feedstock costs are linked to the location of the plant and availability of biomass in the vicinity of the plant. If feedstock availability in the neighbouring area of the plant is low, the proximity to supply routes, such as ports, becomes important. Finally, also due to scale differences, injection costs are 2 €/MWh compared to the almost 10 €/MWh for the case of anaerobic digestion.⁵

⁵ Gasification demonstration projects in Europe include the *Gaya* (FR), *Ambigo* (NL) and *GoBiGas* (Sweden). For the *GoBiGas* project, Thunman et al. (2019) report a slightly higher cost of 60€/MWh. For the *Gaya* project, current costs

Figure 2.5 Break-even price for bio-methane via thermal gasification, per MWh



Source: Authors' own elaboration. Data stem from Table 2.3.

2.5. Hydrogen

2.5.1. Production process

Hydrogen does not exist in a pure form in nature and has to be produced. Currently, the most common technique to produce hydrogen is the so-called Steam Methane Reforming (SMR), a process by which hydrogen is produced from natural gas (CH₄). Hydrogen can also be produced through the electrolysis of water (H₂O). Hydrogen produced through electrolysis can function as a bridge between the electricity system and the gas system, for instance, by acting as a source of demand flexibility in the electricity market.

Both production technologies use different types of energy, i.e., gas in the case of SMR and electricity in the case of electrolysis. SMR typically uses natural gas but, technically speaking, bio-methane produced either from anaerobic digestion or thermal gasification can also be employed. When the carbon emitted during the SMR process is not captured at all, the hydrogen produced is often referred to, informally, as 'grey'. Grey hydrogen has been produced for many years and is currently the only type of hydrogen being produced in large quantities. When the carbon emitted during the SMR process is removed and stored, the hydrogen produced is informally called 'blue'. This technique is increasingly considered as an option to produce hydrogen without carbon emissions. Since this study centres on environmentally-friendly gases, from now on we will only focus on hydrogen produced with CCS. As explained in Box 2.1, we will refer to this as natural gas-sourced hydrogen, or NG-sourced H₂.

Electrolysis uses power, which can be generated in various ways. When the electricity is generated through renewable sources, like wind turbines or solar panels, the hydrogen is produced in a pure renewable way and it is often informally called 'green hydrogen'. As explained in Box 2.1, we will refer to this hydrogen as renewable electricity-sourced hydrogen or RE-sourced H₂. Since users typically cannot distinguish among electricity generated from a renewable source of energy and electricity generated from a non-renewable source as both are generally connected to the same

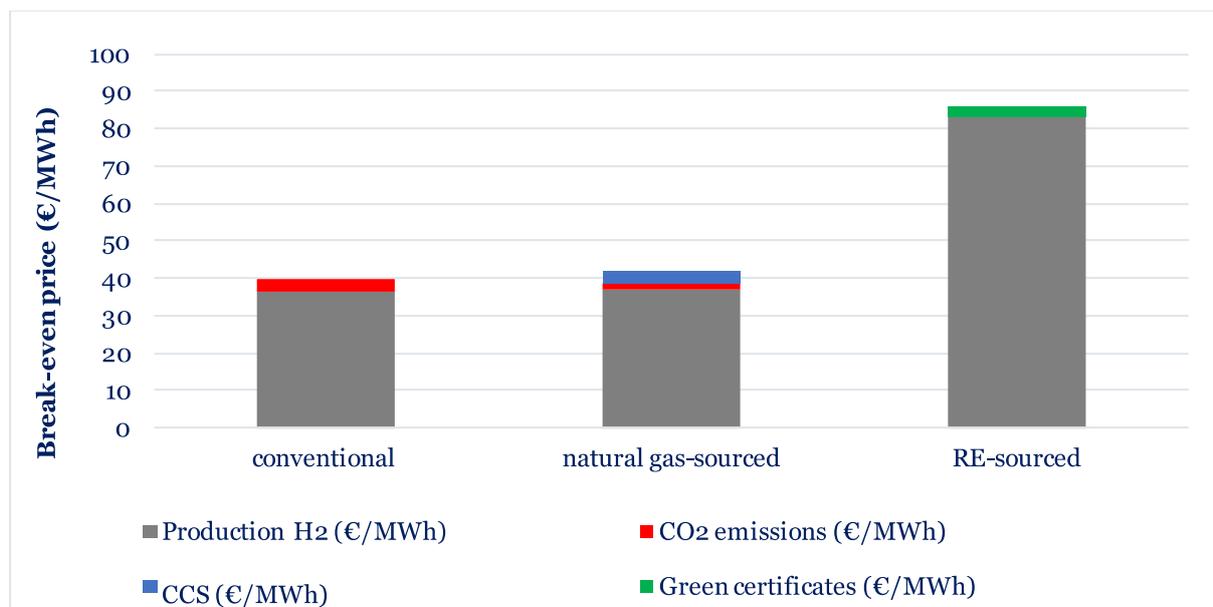
are much higher, around 125 €/MWh, but the expectation is that the costs will be reduced to 60-90€/MWh after optimizing plant size and feedstock mix (see *projetgaya.com*). The Ambigo project is still under construction.

grid, a system of guarantees-of-origin (or certificates) has been implemented in Europe. Users of electricity, in particular electrolysis plants, need these certificates in order to be able to prove that the electricity they use stems from renewable sources of power and the costs of the certificates have to be taken into consideration.

2.5.2. Production costs

Mulder et al. (2019) explored the economic drivers for the different types of hydrogen production based on the relevant literature.⁶ They found that the production costs of hydrogen are highly dependent on the price of the energy input. When the hydrogen is produced using SMR, the critical input is natural gas; for the case of electrolysis, it is electricity. The rest of the cost components, depending on the technology used, are the associated costs of CCS, CO₂ emission permits and renewable electricity certificates. Figure 2.6 depicts the production cost per unit of hydrogen by production technique. The cost of a renewable electricity certificate is set to 2 €/MWh and the CO₂ allowance price is set to 15 €/ton.

Figure 2.6 Break-even price for hydrogen per MWh, by production technology



Source: Authors' own elaboration. Data stem from Mulder et al. (2019)

2.6. Conclusion on production technologies

Anaerobic digestion is a mature technology for the production of biogas, with a limited plant size (maximum of 5 MW of capacity). Costs of bio-methane through anaerobic digestion are highly dependent on the price of the feedstock employed. Excluding feedstock costs, the break-even price for bio-methane produced through anaerobic digestion, including upgrading and injection, is around 100 €/MWh. Feedstock costs vary greatly among regions and as a result so do the unit total costs estimates of bio-methane. Data from various European countries reveal break-even price estimates ranging from 60-120 €/MWh.

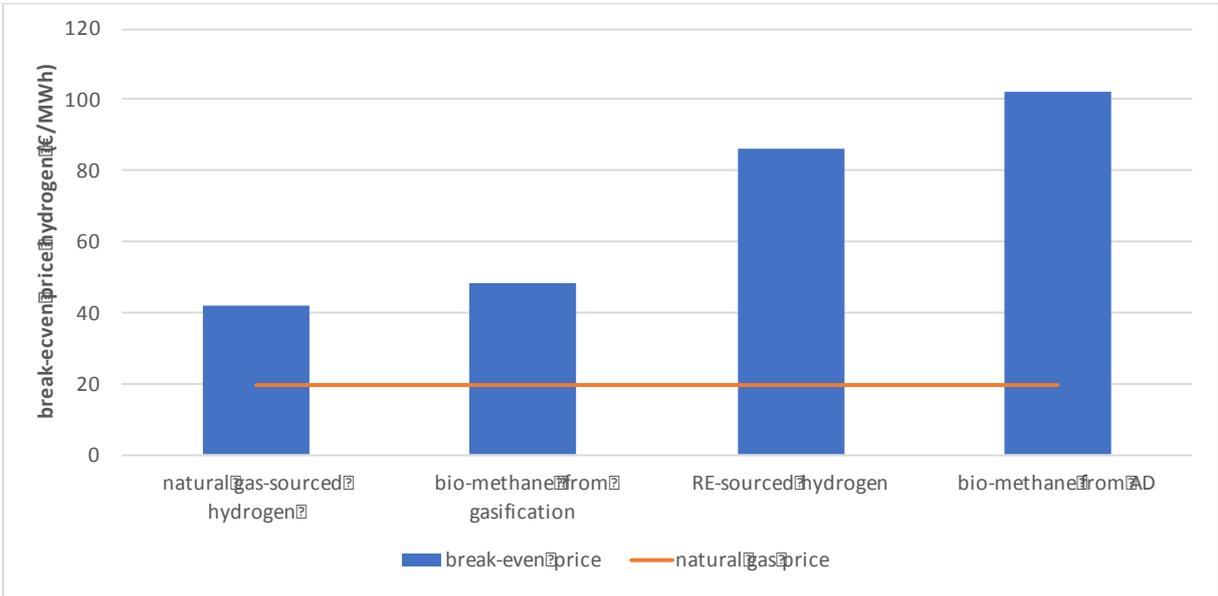
⁶ Some for instance: CE Delft (2018), Chardonnet et al. (2017), Collodi et al. (2017), Dillich et al. (2012), Hydrogen Council (2017), IEA (2017), Krieg (2012).

Thermal gasification is a more infant technology, with a larger expected plant size (up to 1 GW). Upgrading can be done within the same plant, limiting biogas network costs. The break-even price for bio-methane produced from thermal gasification is between 40 and 55 €/MWh.

Hydrogen production is strongly dependent on input prices (natural gas in the case of SMR or electricity in the case of electrolysis). Given current prices of natural gas and electricity, the break-even price for natural gas-sourced and renewable electricity-sourced hydrogen is around 40 and 85 €/MWh, respectively. Hydrogen could be upgraded to methane through methanation, but in the case of natural gas-sourced hydrogen this would be very inefficient due to large associated energy losses. Given that RE-sourced H₂ is still quite expensive, so is methane obtained from the methanation of this type of hydrogen.

Figure 2.7 gives the break-even price for hydrogen and bio-methane by various technologies of production. We include the current natural gas wholesale price as a reference. It is clear that the break-even price for the various technologies is 2 to 5 times as high as the current natural gas wholesale price. One can see that in terms of the break-even price, natural gas-sourced hydrogen is the cheapest production process per unit of energy. As technologies become more efficient and their costs decrease, this picture may change. Moreover, it should be noted that the market demand for hydrogen as an energy carrier is still small compared to the demand for natural gas. Scaling up the production of hydrogen is expected to lower the costs further.

Figure 2.7 Break-even price for hydrogen and bio-methane per MWh, by various technologies, compared to the actual natural gas price (average past decade)



Source: Authors' own elaboration based on previous Figures and Bloomberg L.P.

3. Supply of renewable gases and hydrogen

3.1. Introduction

After exploring the costs of the alternative technologies for the production of renewable gases and hydrogen in the previous chapter, we now move to the potential supply of the various types of gases. In Section 3.2, we look at the current supply of the different gases in the selected European countries. Thereafter, in Section 3.3, we estimate the likely potential.

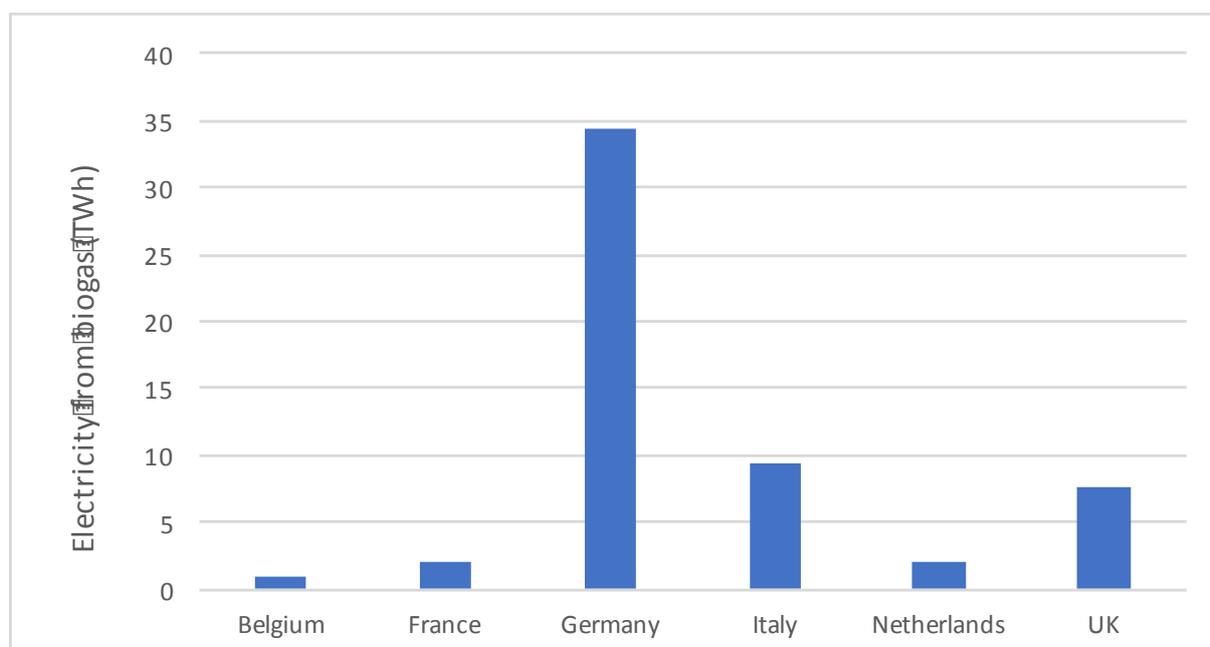
3.2. Current supply of renewable gases and hydrogen

3.2.1. Current supply of biogas

The most recent data on the current supply of biogas in Europe is available from EBA (2018). Figure 3.1 gives the electricity generation from biogas in the countries studied. The Figure shows that, in 2017, Germany, with approximately 35 TWh, was by far the largest producer of electricity from biogas. Germany began producing biogas early, with the passing of the Electricity Feed-In Law in 1991. This ruling gave renewable electricity priority access to the network. In the following years, the country introduced additional support schemes (details in chapter 6). This helped the sector to continue to grow and reach the current significant size.

Other countries, such as Italy and the UK, have also supported biogas for a number of years already. However, by looking at Figure 3.1, one can see that such a support did not always result in a high output of biogas. This is because there are other technical and environmental restrictions that affect the production of biogas. These constraints will be addressed in section 3.3, where we look at the potential of the different gases.

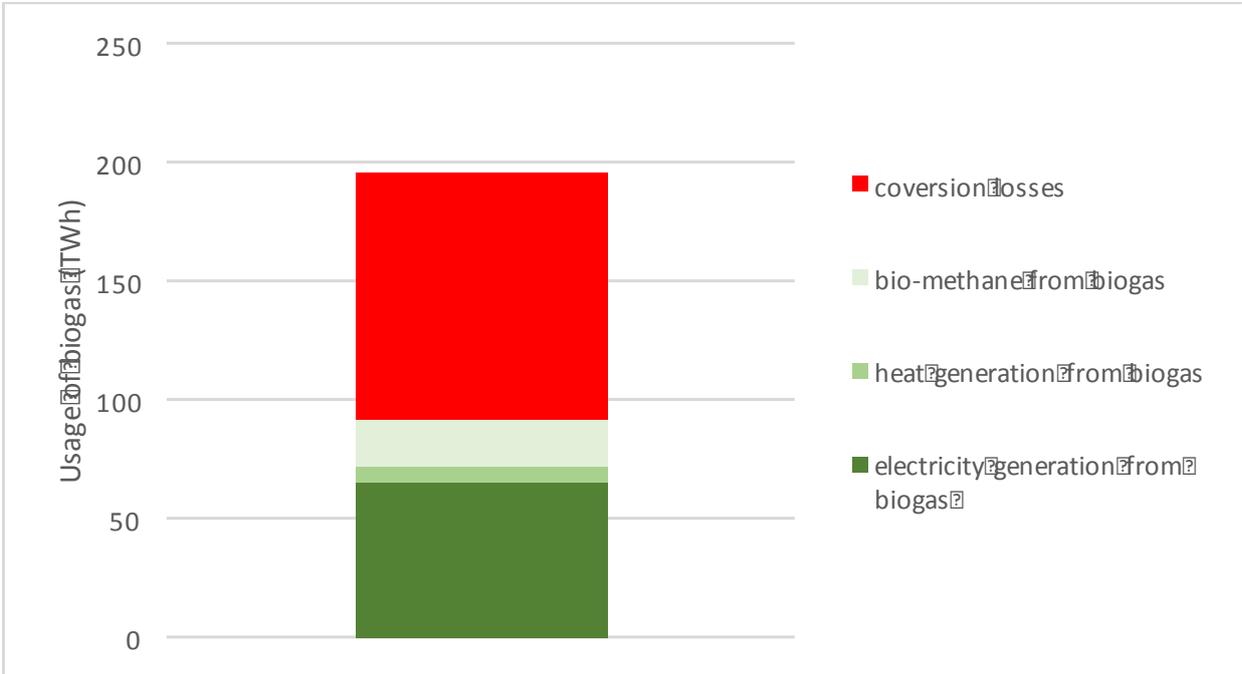
Figure 3.1 Electricity production from biogas, by country in 2017



Source: Authors' own elaboration. Data stem from European Biogas Association (2018)

As mentioned earlier, biogas from anaerobic digestion can be used in various ways (electricity generation, heat generation and conversion to bio-methane). Figure 3.2 shows the usage of biogas in the EU in 2017. Roughly one third of the energy content of biogas was converted into electricity and heat, mainly in combined heat and power (CHP) plants. The electricity production from biogas, over 65 TWh, equals roughly 2% of the total electricity production in the EU. Only a very small proportion of biogas was upgraded to bio-methane. As one can see, more than half of the total energy content is lost. Most of the losses are due to the lack of heat valorisation from electricity generation. Converting biogas to bio-methane also implies some energy losses, although these are smaller.

Figure 3.2 Usage of biogas in EU-28, in 2017

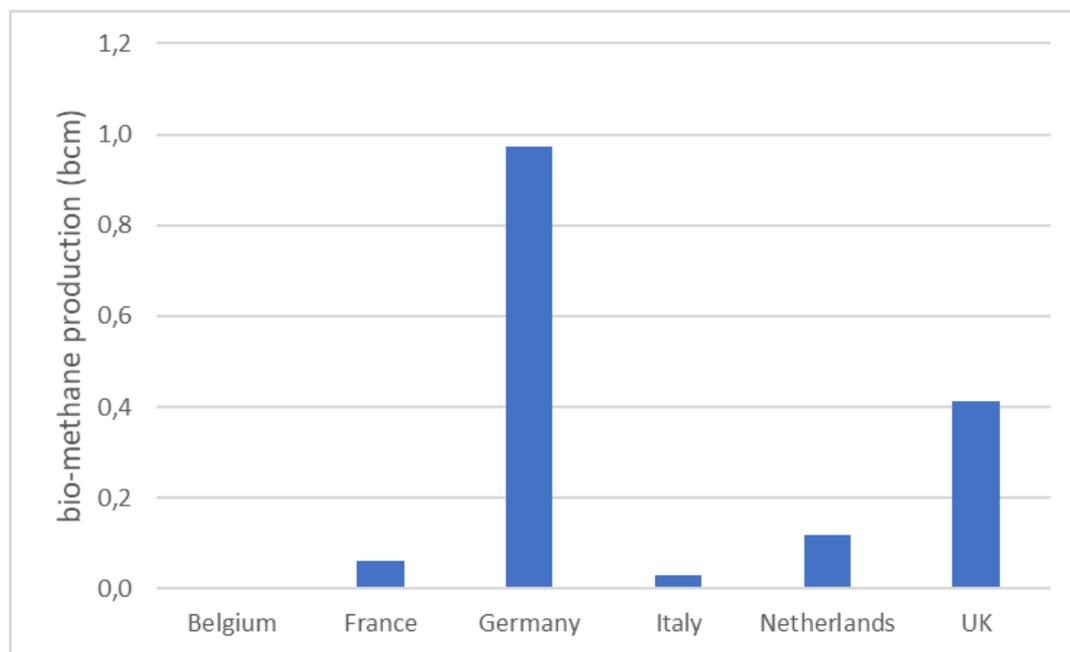


Source: Authors' own elaboration. Data stem from European Biogas Association (2018)

3.2.2. Current supply of bio-methane

Qualitatively speaking, the current supply of bio-methane in the countries of interest is comparable to the supply of biogas. As can be seen in Figure 3.3, Germany is again by far the largest supplier, with almost 1 billion cubic metres (bcm) of bio-methane production. The United Kingdom ranks second, with less than half of that amount. The production of bio-methane is small compared to the production of natural gas.

Figure 3.3 Bio-methane production per country, in 2017



Source: Authors' own elaboration. Data stem from European Biogas Association (2018)

3.2.3. Current supply of hydrogen

In comparison to the energy market, the market for hydrogen in Europe is still small. Up to now, hydrogen is mainly used as feedstock in the chemical industry, for the production of ammonia and methanol in the refining industry, where it is used to crack heavier crudes and produce lighter crudes, and in the metal industry for the production of iron and steel (see Figure 3.4). In the future, however, the market for hydrogen may grow strongly. In fact, hydrogen is increasingly seen as a potential energy carrier to provide high-temperature process heat, heat buildings and produce electricity, while it is also expected that it can become a major fuel in transport (Certify, 2016; CE Delft, 2018; Hydrogen Council, 2017; IEA, 2017; WEC, 2018). In addition, hydrogen may play a role in helping the electricity sector deal with the increasing shares of renewable power by offering a source of flexibility regarding the timing and location of production (Van Leeuwen and Mulder, 2018).

Figure 3.4 Market segmentation European hydrogen market

INDUSTRY & MARKET SHARE	KEY APPLICATIONS	SUPPLY SYSTEM	H2 DEMAND
 General Industry 1%	<ul style="list-style-type: none"> • Semiconductor • Propellant Fuel • Glass Production • Hydrogenation of Fats • Cooling of electrical Generators 	<ul style="list-style-type: none"> • Small on-site • Tube trailers • Cylinders • Liquid H2 	LOW >0.07 Mtons
 Metal Working 6%	<ul style="list-style-type: none"> • Iron Reduction • Blanketing gas • Forming gas 	<ul style="list-style-type: none"> • Cylinders • Tube trailers 	MEDIUM 0.41 Mtons
 Refining 30%	<ul style="list-style-type: none"> • Hydrocracking • Hydrotreating 	<ul style="list-style-type: none"> • Pipeline • Large On-site 	2.1 Mtons
 Chemical 63%	<ul style="list-style-type: none"> • Ammonia • Methanol • Polymers • Resins 	<ul style="list-style-type: none"> • Pipeline • Large On-site 	HIGH 4.3 Mtons

Source: Certifhy (2015)

3.2.4. Conclusion current supply

In conclusion, if we analyse the current weight of renewable gases and hydrogen in the energy mix, it becomes evident that the joint share of these gases is still very limited. Although the implementation of different support schemes has led to a considerable growth in, for example, Germany, the market size still remains small.

In the EU-28, electricity generation from biogas makes up roughly 2% of total electricity production, with more than half of it being produced in Germany. For biogas upgraded to bio-methane, we observe similar figures. The total production of bio-methane in the EU-28 was 1.94 bcm in 2017, which equals 0.8% of the total natural gas production in the same region for the same year (247 bcm). Again, Germany is by far the largest producer with half of the total bio-methane production.

Finally, we looked at the current market size of hydrogen. Although there is a worldwide growth in hydrogen demand, this is mainly caused by the increase in demand from regions other than Europe. The European hydrogen demand was estimated by Certifhy (2015) at over 250 TWh, or roughly 25 bcm of natural gas equivalent, which is equal to 1.3% of total energy consumption in the EU (or 5% of the total natural gas consumption of 487 bcm). Almost all of the hydrogen is used in industry, with ammonia plants accounting for half of the total hydrogen demand. Most of the hydrogen (about two-thirds) is produced on-site or sold in a captive market. About 30% of hydrogen is produced as a by-product of other processes and then commercialised. Only 10% of the hydrogen is sold on open, competitive markets.

3.3. Potential supply of renewable gases, based on current feedstock availability

In order to determine the potential supply of bio-methane and hydrogen, we look at the technical and environmental constraints the production of these gases face. In order to give perspective to the potential supply of bio-methane and hydrogen, we compare it to the current size of the natural gas market. It is important to note that the technical potential of the renewable gases is based on the *current* situation in the countries investigated. If, for example, the consumption of meat or dairy products declines, as the United Nations has recently recommended curbing emissions, manure availability will decrease as a result, and hence the potential for bio-methane. We will first analyse the potential of bio-methane produced from anaerobic digestion, followed by bio-methane produced from thermal gasification; finally, we will examine the potential supply of hydrogen, with special focus on the potential supply of RE-sourced hydrogen.

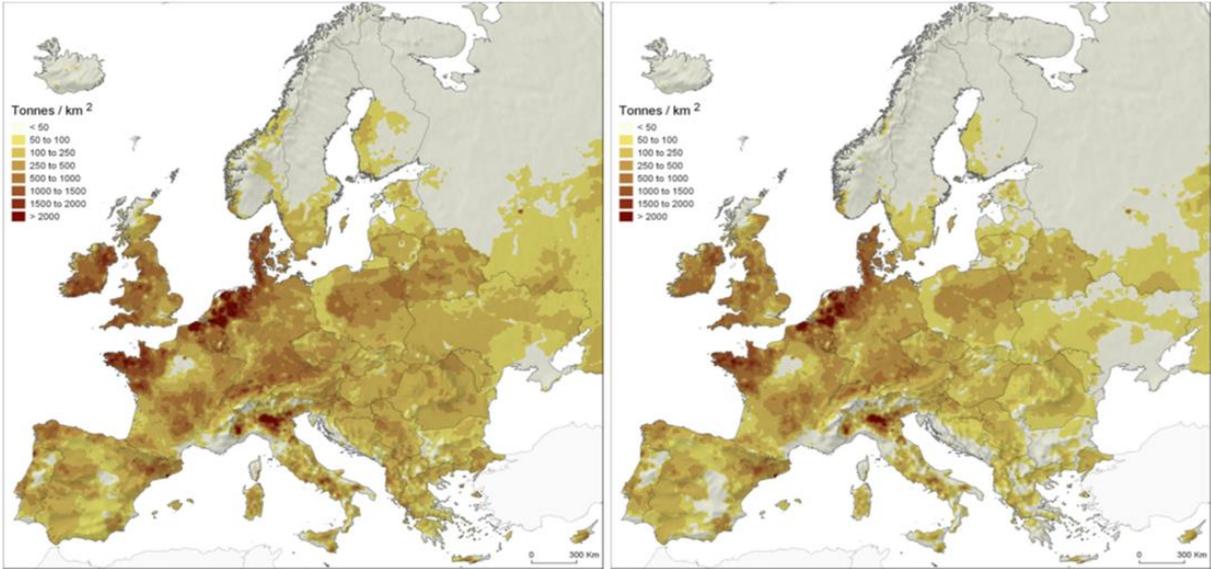
3.3.1. Potential supply of bio-methane from anaerobic digestion

We start with the potential for bio-methane produced from the upgrading of biogas produced in small scale digesters. The upgrading units do not have a maximum capacity, simply because more units can be added when demand rises. The potential is thus determined by the availability of feedstock. We identified two main feedstock types for anaerobic digestion: manure and crop residues.

To assess the potential from manure, we follow Scarlat et al. (2018). Using the density of manure potential as depicted in Figure 3.5, and taking into account that transporting feedstock over distances greater than 25 km is not economical, they calculated where the digesters could be placed and what the cumulated production of biogas would then be. Using our estimations from the previous chapter, we then calculated how much bio-methane could be produced from this biogas. The results are reported in Figure 3.7.

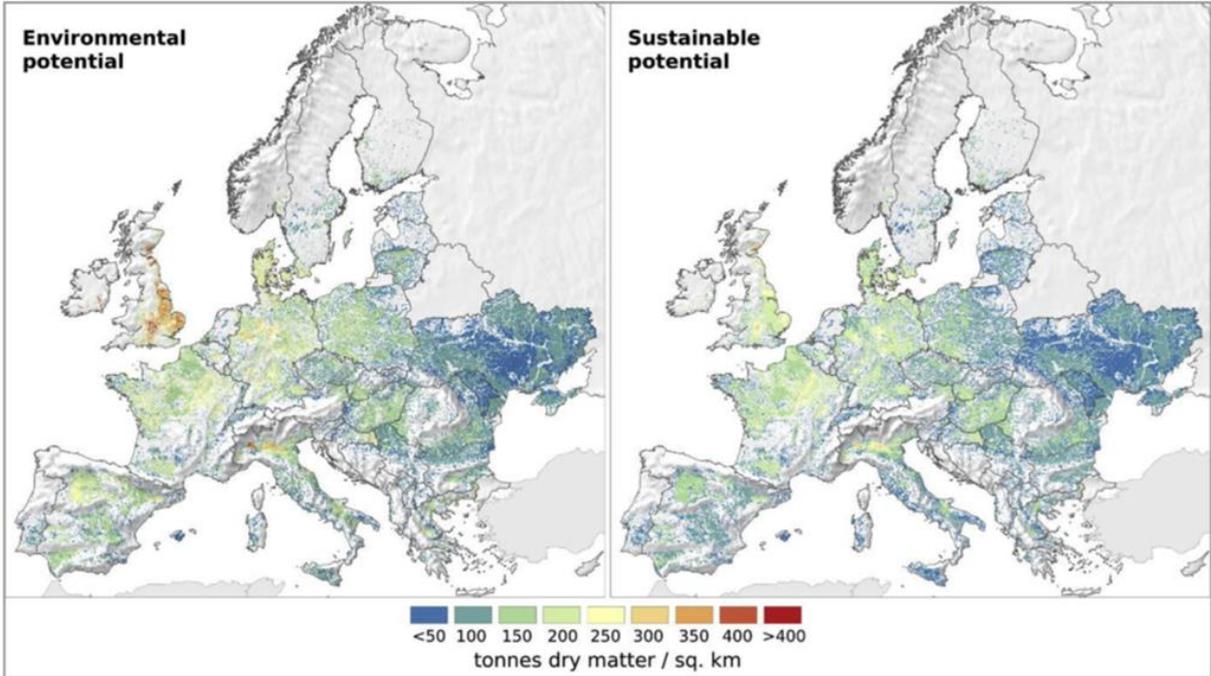
The same method is used for the estimation of the bio-methane potential from crop residues (Scarlat et al., 2019). For the calculation of the potential bio-methane from crop residues, the authors calculated the crop residues that could be harvested in a sustainable manner (see Figure 3.6). The volume of bio-methane corresponding to these crop residues is depicted in Figure 3.7. Combined, the total potential for the countries of interest is approximately 37 bcm. Navigant (2019) estimated the potential bio-methane production from AD for the EU to be 63 bcm. Looking at Figure 3.5 and Figure 3.6, one can see that the difference can be explained by the countries that are excluded from our estimates.

Figure 3.5 Density of manure production (left) and collection (right) potential for anaerobic digestion



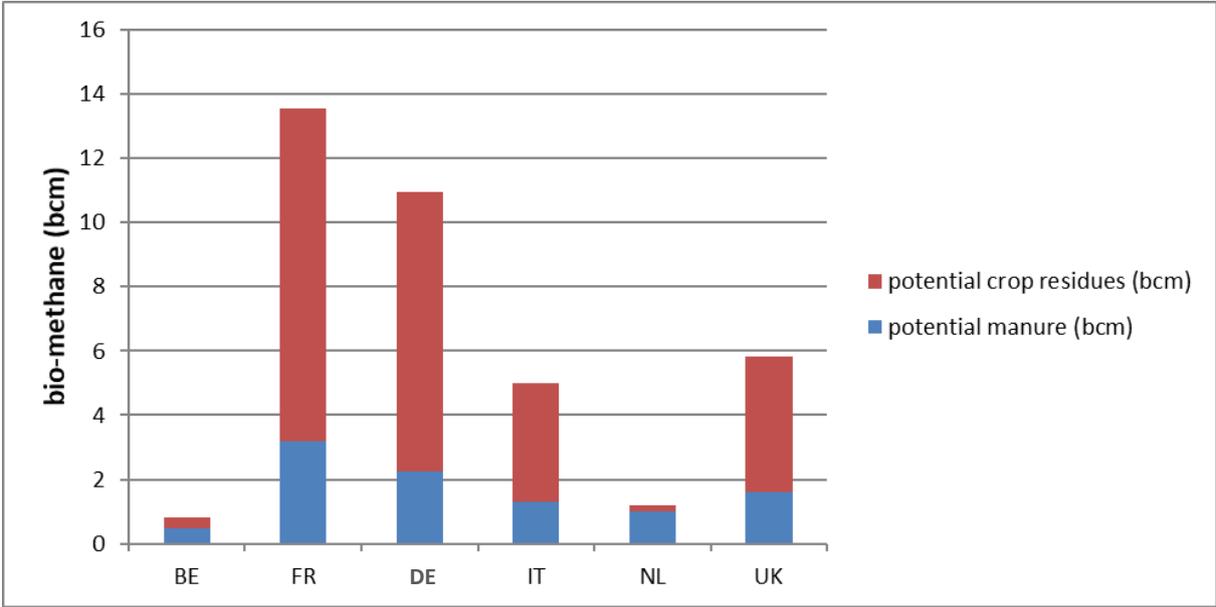
Source: Scarlat et al. (2018)

Figure 3.6 Density of crop residue potential for anaerobic digestion



Source: Scarlat et al. (2019)

Figure 3.7 Potential bio-methane production from anaerobic digestion, based on current feedstock availability, per input, per country

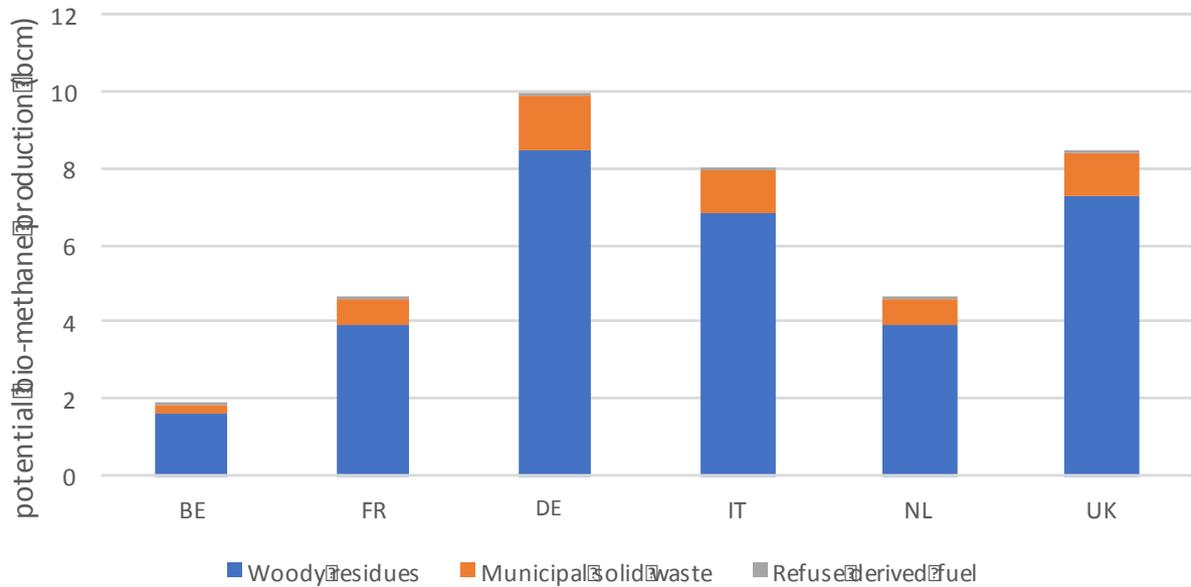


Source: Authors' own elaboration. Data stem from Scarlat et al. (2018), Scarlat et al. (2019)

3.3.2. Potential supply of bio-methane from thermal gasification

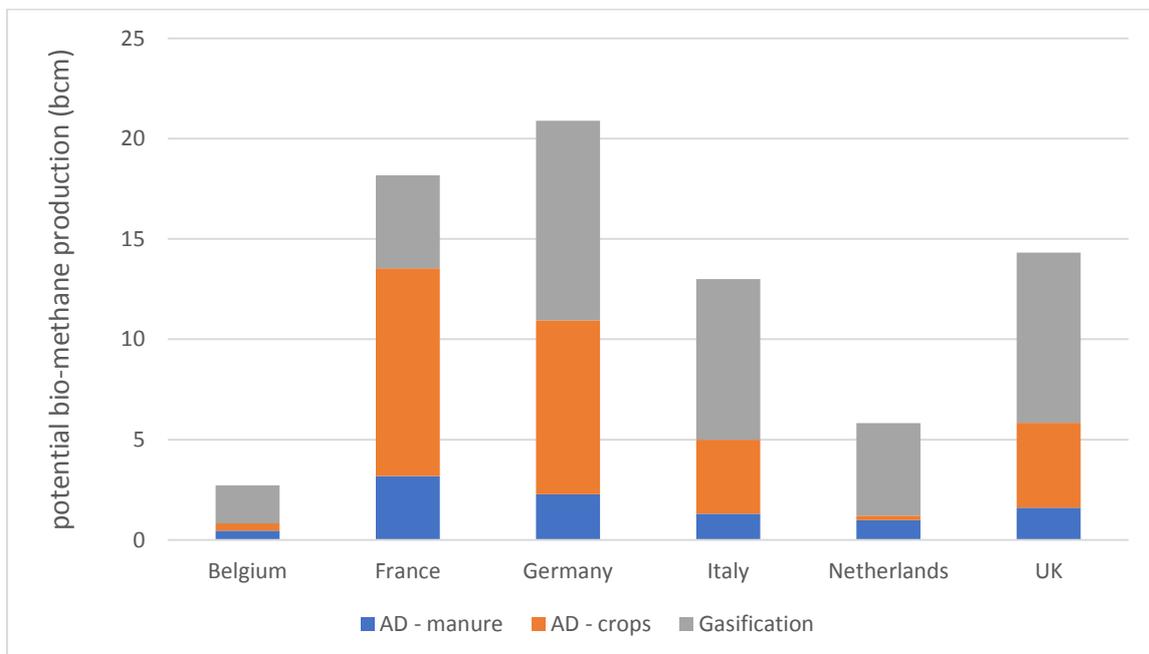
The production of bio-methane from thermal gasification has constraints different from those affecting anaerobic digestion. While the location of the plant is important for the latter, for thermal gasification this is not the case. Since quantities are large and the feedstock is easier to transport, inputs for these plants can be imported from further locations. Therefore, rather than looking at the inputs available domestically, building on Navigant (2019), we take all the inputs available at the European level. We then estimate the potential bio-methane production from gasification for the countries studied by proportioning according to each country's share of gas demand in total EU demand. Figure 3.8 reports the potential bio-methane production from gasification for the countries of interest. Combined, we find a potential of 38 bcm of bio-methane from gasification. Remarkably, this figure is higher than the potential of 33 bcm reported by Navigant (2019) for the entire EU. One reason for the difference could be the underlying assumptions on plant efficiency.

Figure 3.8 Potential bio-methane production from gasification, based on current feedstock availability, per country, per input



Source: Authors' own elaboration. Data stem from Navigant (2019) & IEA (2018)

Figure 3.9 Total potential bio-methane, based on current feedstock availability, per country, per input



Source: Authors' own elaboration based on previous Figures

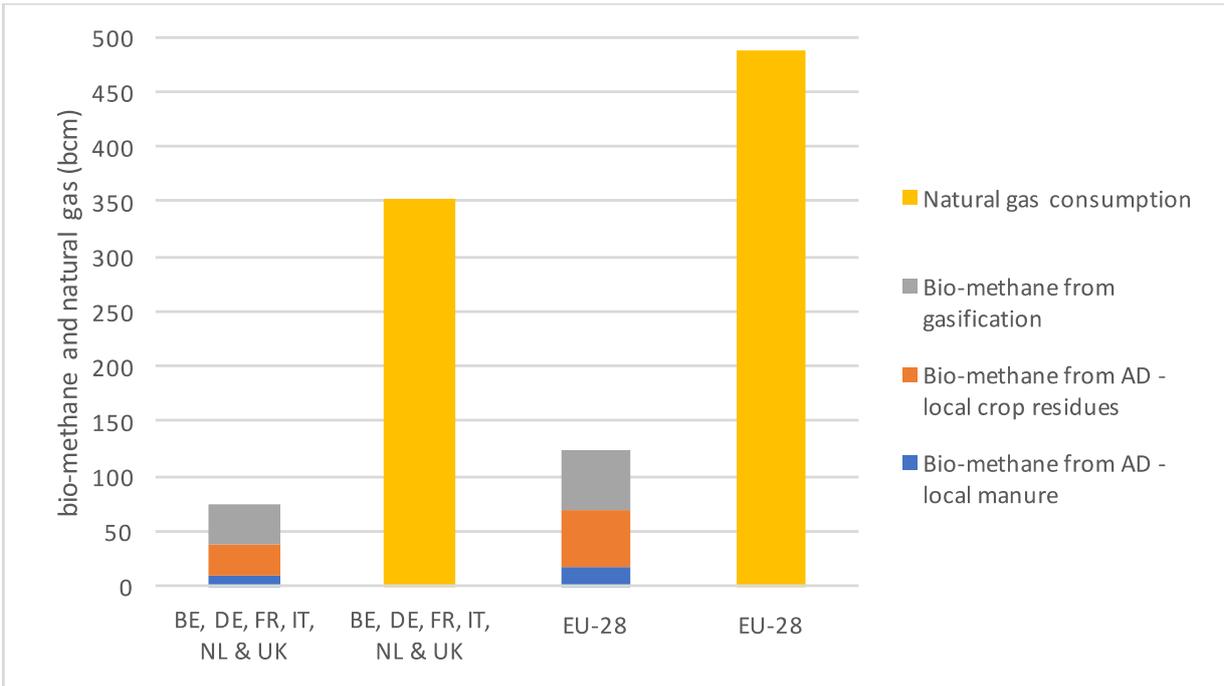
In Figure 3.9, we combine the potential of the different technologies and inputs. In absolute terms, Germany has the highest potential bio-methane production, with over 20 bcm. When comparing

the potential bio-methane production with the current natural gas demand, France scores highest with the potential to replace 42% of the current natural gas consumption with bio-methane. The other countries score significantly lower.

In Figure 3.10, we combine the potential for the six countries of interest. As one can see, the total potential of bio-methane production for the countries of interest is estimated to be around 75 bcm. This is roughly one-fifth of the joint natural gas consumption of Belgium, Germany, France, Italy, The Netherlands and the United Kingdom. So, unless the demand for gas declines significantly during the development of the renewable gas industry, the potential is substantial but not nearly enough to replace natural gas.

Using data from Scarlat et al. (2018, 2019), and the same methodology, we can compute the potential of bio-methane at the EU-28 level. We also report this in Figure 3.10. The total EU-28 potential for bio-methane from AD is 68 bcm and that from gasification is 56 bcm. Together they total 124 bcm of bio-methane at the EU-28 level. This represents close to a quarter of the total 2017 natural gas consumption in the EU-28.

Figure 3.10 Potential bio-methane production based on current feedstock availability, compared to natural gas consumption, for selected countries and EU-28



Source: Authors' own elaboration based on previous Figures and Scarlat (2018, 2019).

3.3.3. Potential supply of hydrogen

The potential supply of hydrogen is hard to assess. While the main limitation for bio-methane is the availability of feedstock, this problem does not occur with hydrogen. The main factor behind the potential supply of hydrogen is the future volume of demand, although the availability of CO₂ storage infrastructure and renewable electricity capacity may be important constraints in the case of natural gas-sourced and RE-sourced hydrogen, respectively.



The future potential of hydrogen depends on how demand and supply are expected to evolve. Regarding the potential demand for hydrogen, Mulder et al. (2019) show that, for the case of the Netherlands, in certain scenarios it is possible that the demand for RE-sourced and natural gas-sourced hydrogen grows significantly. The main determinant behind this future demand is the stringency of European climate policy, which is, for example, reflected in the price of CO₂ emission permits and the magnitude of natural gas taxation. These macro-economic drivers are not country specific and can be seen as determinants for hydrogen in Europe. If European climate policy is very stringent and natural gas prices are low, there will be a large demand for NG-sourced H₂. On the contrary, if natural gas prices are high, RE-sourced H₂ will become more attractive. In their analysis, Mulder et al. (2019) construct scenarios for the development of hydrogen demand in the Netherlands. The potential demand in 2050 for hydrogen ranges from the current level (roughly 30 TWh) to an almost 800% increase in demand (roughly 260 TWh). Although Mulder et al. (2019) focus their scenarios on the Netherlands, their insights are applicable to other European countries as well. A 'back-of-the-envelope' calculation suggests that in the most favourable scenario for hydrogen demand, the European level of demand could equal almost 2200 TWh.⁷ This figure is comparable to those provided by Navigant (2019) and Hydrogen Roadmap Europe (2018), which report 2000 TWh (RE-sourced hydrogen only) and 2251 TWh as 2050 potentials, respectively. Note, however, that these estimates refer to the most favourable outlook for hydrogen demand and there are strong (but not unrealistic) underlying assumptions, such as a CO₂ allowance price of 50 €/ton and an industry tax on natural gas of 30 €/MWh.

Regarding the expected supply of hydrogen to meet the potential demand, the question that arises is whether there are limitations in the supply of natural gas-sourced and RE-sourced H₂. The supply of natural gas-sourced hydrogen is theoretically limited by two factors: availability of natural gas and availability of CO₂ storage. The first is not considered a limitation, since the usage of natural gas is expected to diminish in the future. However, the availability of CO₂ storage is currently seen as an important limitation. The limitation is not due to a shortage of storage capacity, but rather by public acceptance. Navigant (2019) also report NG-sourced H₂ as "a scalable and cost-effective option" and "an accelerator of the decarbonisation of the gas consumption", but not as an effective solution for 2050.

In regard to RE-sourced hydrogen, the vast majority of the literature reports a promising potential for hydrogen from excess renewable electricity, which otherwise would be curtailed. Indeed, the planned strong growth in renewable electricity capacity in Europe implies a significant growth in peak-supply and therefore in the spells of over-supply. Navigant (2019) estimates the potential of European hydrogen from excess renewable electricity to be 200 TWh (18 bcm of natural gas equivalent) by 2050. This is only 10% of the potential demand in the most favourable scenario, leaving a large potential demand to be met by hydrogen produced from electrolysis using 'regular' renewable electricity. However, this potential could be much higher using dedicated wind and solar resources as well as electricity imports from regions outside the European Union, potentially meeting the entirety of estimated demand for hydrogen in Europe (1710 TWh).

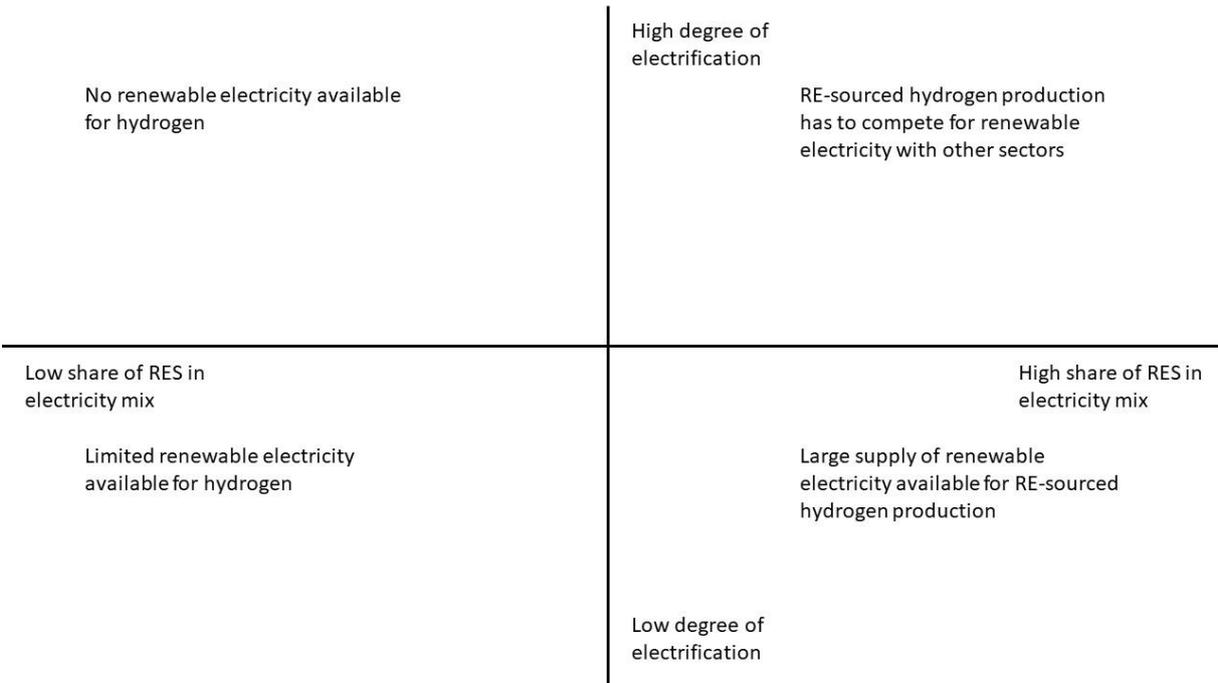
As explained in Mulder et al. (2019), a difficulty for the development of RE-sourced hydrogen is the tension with climate policy. They point out that an efficient climate policy requires a good reflection of the negative externalities, hence a high price for carbon allowances. A higher carbon price, the argument goes, will be reflected in the electricity price, which will then become higher as well. Since RE-sourced hydrogen uses electricity as a main input, this will lead to higher costs of producing RE-sourced H₂. This tension will remain even if the share of renewables is already high,

⁷ This is calculated as current hydrogen demand (250 TWh) multiplied by the factor found by Mulder et al. (2019) in the most favourable scenario for hydrogen demand.

as investors in renewable electricity will only recoup their investments if the prices are relatively high. However, the higher the share of RE generation, the smaller this effect will become.

Alternatively, Mulder et al. (2019) considered a scenario where demand for renewable electricity not only increases because of hydrogen production but also because of other sectors (mainly, electrification of houses and mobility). In principle, such a scenario is more favourable for RE-sourced H₂. However, this does not appear to be the case. The authors found that even with a high growth rate of RE production, the increase in electricity demand (a doubling of current demand) cannot be met by renewable electricity generation. The implication of the share of renewable electricity supply (RES) in the electricity mix and the degree of electrification on the competitiveness of RE-sourced H₂ is depicted in Figure 3.11. Navigant (2019) find similar results and argue that the ramp-up of renewable RE-sourced hydrogen is linked to the capacity of wind and solar energy.

Figure 3.11 The effect of share of RES in electricity mix and degree of electrification on potential RE-sourced hydrogen production



Source: Authors' own elaboration

Another limitation for RE-sourced H₂ is the intermittency of renewable electricity. When a RE-sourced H₂ plant solely uses electricity generated by wind turbines, for instance, the production is highly volatile. This greatly reduces the efficiency as well as the number of operating hours, limiting the potential production for a competitive price.

Finally, it is important to note that the potential demand and supply are derived assuming that hydrogen can readily be used in all applications. In reality, however, there are significant switching costs when changing infrastructures. High deployment of hydrogen would require either retrofitting the natural gas grid or deploying a new grid, as well as the adaptation of all final appliances for using hydrogen. This implies significant extra costs and hence, a limitation for the potential of hydrogen.

3.3.4. Conclusions on potential supply

For the different bio-methane and hydrogen production technologies we discussed in Chapter 2, there are different aspects determining their potential. Since renewable gases and/or hydrogen are expected to substitute natural gas, the demand side is not expected to be a limiting factor.

For renewable gases injected into the grid, the infrastructure is not expected to restrain their potential. In contrast, the theoretical annual potential is in all cases constrained by the availability of the inputs. The potentials we report are based on the current situation and will be different in the future when factors influencing input availability change over time, such as the utilisation of the inputs for other purposes, or changes to regulation and legislation.

For the production of bio-methane via anaerobic digestion of manure, the proximity of the feedstock to the plant represents an important constraint. When, instead, the residues of harvest crops are used, the maximum production is constrained by considerations relating to the sustainability of land. These restrictions lead to a combined potential of approximately 37 bcm in the countries of interest, and 68 bcm for the EU-28 as a whole.

For the case of thermal gasification the feedstock can be imported more easily, so large production facilities can be placed all over Europe. Therefore, the maximum production can best be derived taking all the inputs available in Europe. We then calculated the potential production per country as a share of total potential. The share per country taken is proportional to their share in the EU natural gas consumption. The combined potential of bio-methane from thermal gasification for the countries of interest is estimated to be approximately 38 bcm, and for the EU-28 as a whole 56 bcm.

Altogether, this would give a potential bio-methane supply of roughly 75 bcm for BE, DE, FR, IT, NL, and UK, which is slightly over 20% of their joint 2017 natural gas consumption. For the EU-28 we estimate a total potential of 124 bcm, which is close to 25% of the current natural gas consumption in the same region.

The potential of natural gas- and renewable electricity-sourced hydrogen is very hard to assess. Since the corresponding inputs of production are natural gas and electricity, theoretically speaking, the maximum production is very large. It is identified that the first determinant for the potential is the demand for hydrogen. From various sources (see e.g. Mulder et al, 2019) we find a maximum potential demand for hydrogen of 2200 TWh (almost 200 bcm of natural gas equivalent), in the most favourable scenario.

The potential supply of natural gas-sourced hydrogen is quite large, conditional on a significant development of CCS technology and its public acceptance (see Schumann et al., 2014). Because European policy-makers aim at a zero carbon emissions economy by 2050, we believe CCS technology will benefit from large scale implementation and its social acceptance will rise as popular awareness about climate change mitigation increases.⁸

RE-sourced hydrogen could be produced from excess renewable electricity in times of over-supply. According to Navigant (2019), the potential of European hydrogen production from excess RE is estimated to be 200 TWh (about 18 bcm), which is slightly under 10% of the maximum potential of

⁸ Strictly speaking, note that in order to contribute to a zero carbon emission economy, the CCS technology has to be sufficiently advanced in order to capture all the carbon emissions from hydrogen production.



hydrogen demand. However, this potential could be much higher using dedicated wind and solar resources as well as electricity imports from regions outside the European Union, potentially meeting the entirety of estimated demand for hydrogen in Europe (1710 TWh). A limitation for RE-sourced H₂ produced by RE from the grid is the tension with climate policy: electrolysis plants need a low price for renewable electricity to be competitive, while producers of renewable electricity need high prices to recoup their investments. A strong climate policy implies a high carbon price, which, in turn, will raise the price of electricity and will limit the competitiveness of RE-sourced H₂. Other limitations for RE-sourced H₂ are the popularity of renewable electricity in other sectors (raising the price for renewable electricity) and the intermittent aspect of RE, which strongly reduces the efficiency of an electrolysis plant.

Finally, a high deployment of hydrogen requires significant investments in infrastructure (retrofitting the existing natural gas grid or deploying a new grid) and final appliances (adaptation of boiler burners and the like).



PART 2

ECONOMIC REGULATION

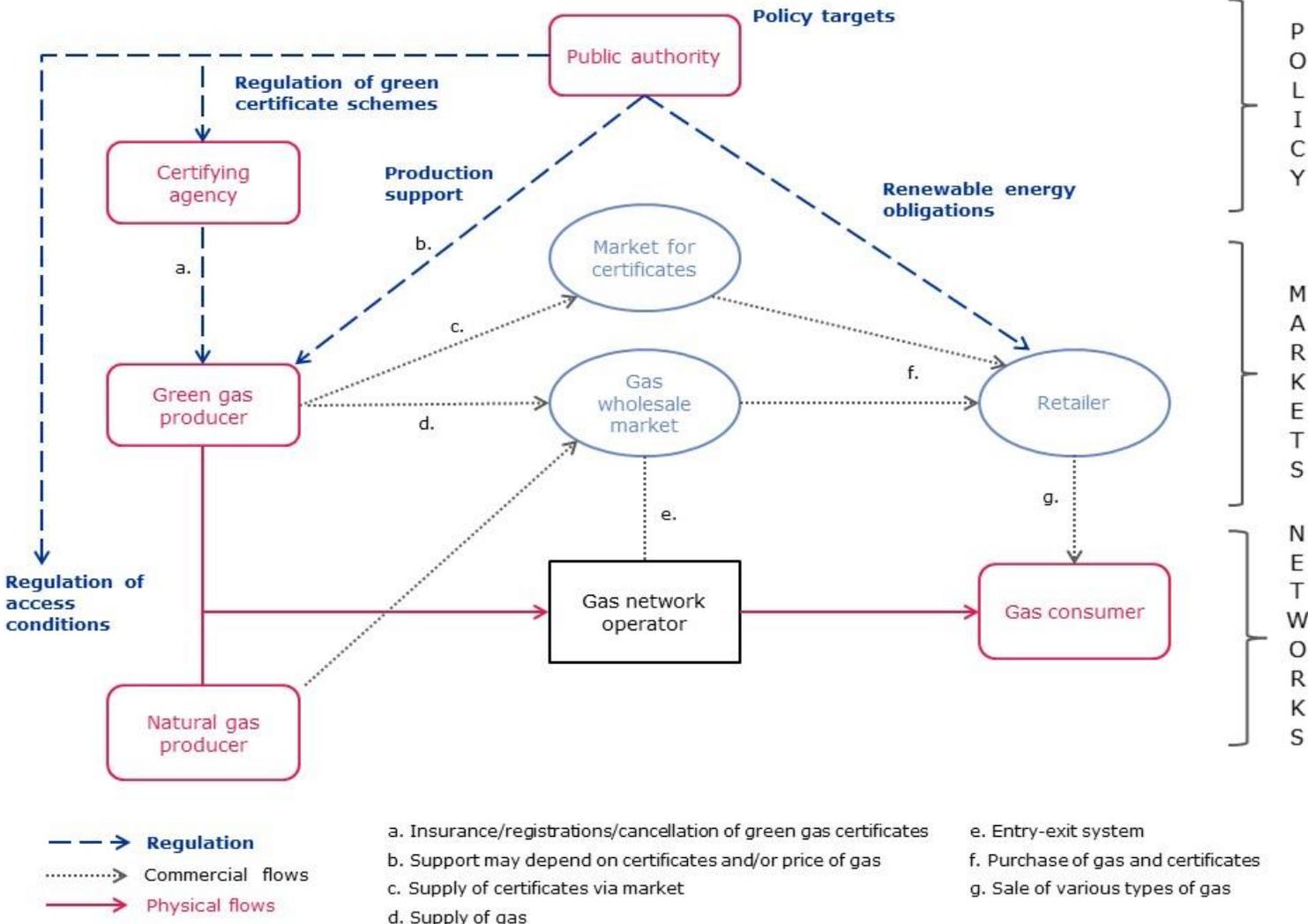
4. Introduction to economic regulation

4.1. Introduction

Regulation in general may be defined as the “State imposed limitation on the discretion that may be exercised by individuals or organisations, which is supported by the threat of sanction” (Stone, 1982). More concretely, economic regulation refers to “government-imposed restrictions on firm and/or consumer decisions over price, quantity, and entry and exit” (Viscusi et al., 2005). In what follows, we provide an analytical framework for the economic regulation of renewable gases and hydrogen.

The economic regulation of the market for a specific gas is meant to improve the position of this type of gas in the overall gas market on the basis that its unfavourable position is due to market failures. The previous chapters have shown that without any additional regulatory measures, the producers of renewable gas and hydrogen cannot compete with the producers of natural gas as the costs of producing these gases are significantly higher. In order to improve their competitive position vis-à-vis natural gas, regulators have a number of options. These options can be grouped into 5 categories (see Figure 4.1). The first category consists of the formulation of policy targets that describe the objectives governments want to achieve. The next category refers to a basic pre-condition for any further regulation, which is making the supply of a renewable gas traceable through the creation of schemes for guarantees of origin (GOs). Another key condition for a renewable gas is that producers have access to the gas infrastructure. The third category, therefore, refers to the regulation of the conditions for this access. An option to help producers is to give them favourable conditions for getting access to the gas network, which will also reduce their costs or increase their ability to inject the gas into the network.

Figure 4.1 Analytical framework economic regulation of renewable gases and hydrogen: 5 regulatory areas



Source: Authors' own elaboration



Even if renewable gas is traceable and can be injected into the grid, because of its relatively high cost, the producers may still find it difficult to operate in a market in which the price of gas is low. Thus, the fourth category of regulatory measures consists of the introduction of production support schemes meant to reduce the costs of producers of RE gases and H₂ in order to enable them to compete with natural gas. The fifth and last category of regulatory measures is to foster demand for RE gases and H₂, for instance, by imposing renewable energy obligations on retailers. Such regulatory measures oblige gas retailers who wish to sell to households to purchase a minimum percentage of RE gas.

In the next chapters we will analyse the current regulatory measures. We start with the formulation of policy targets regarding RE gases and H₂ (Ch. 5). Then we proceed to the regulation of the design of GOs schemes (Ch. 6), the regulation of the conditions for making use of the gas network (Ch. 7) and, finally, the support schemes through production subsidies and renewable energy obligations (Ch. 8). In each chapter, we will first describe the current regulations in place, and then assess these regulations. These assessments are based on a micro-economic framework, which is briefly described in the next section. Based on the assessment of the regulation, we formulate a number of policy recommendations in the final chapter of this report.

4.2. Micro-economic framework for assessing regulation

The micro-economic framework offers an analytical reference system to look at markets and regulation. The basic idea is that markets should only be regulated if there are market failures and the regulatory costs are lower than the expected benefits of regulation. In the absence of market failures, markets are considered to be perfect, which means that they result in the highest possible welfare for society. The notion of perfectly functioning markets is, however, not meant to describe real-world markets but as an analytical benchmark for assessing markets. Most of the real-world markets are not perfect and suffer from one or more market failures.

Drawing from Mulder et al. (2019), these market failures relate to the presence of externalities, market power, information asymmetry and/or hold-up situations:

- Negative externalities occur when economic agents do not take into account all costs of their activities. This market failure may result in a level of activities that is too high from a social point of view. An example of this market failure is carbon emissions resulting from the use of fossil energy.
- Positive externalities, on the contrary, arise when economic agents do not fully internalise all the benefits of their activities. In such a case, the market may deliver a level of activity that is too low. This may, for instance, occur if the benefits of innovation cannot be protected by the innovative firms. In that case, firms will not innovate enough.
- Network externalities occur when the value of a product or service is higher (or lower in the case of negative network externalities) the larger the number of users. Network externalities may result in a limited number of suppliers capturing the full market and, as a result, other firms are unable to enter the market. If network externalities exist, market parties should coordinate on how to organise the market, or a regulator should impose regulations on market design.
- Economies of scale and scope may result in structural positions of dominance (market power) and as a consequence, a level of activity that is too low. This may occur when the provision of a good requires firms to incur very large fixed costs, such as investments in networks. In these situations, it is cost-efficient that one firm provides the good but, absent regulation, the provision will be suboptimal.

- Information asymmetry may result in the so-called adverse selection. This may occur when consumers cannot fully assess the characteristics (e.g. quality) of a commodity. In such a case, consumers will not be prepared to pay their maximum price. If this market failure occurs, coordination or regulation is required, for instance, by organising a trustworthy certification scheme.
- Hold-up occurs when one of the parties to a contract has to make non-contractible transaction-specific investments. In such a case, investment may be too low because firms are uncertain about the revenues they will get in the future. In the absence of long-term contracts with customers, or when liquid markets do not exist, an energy producer may be held-up if it has to make a long-term investment to be able to serve consumers. If this market failure is present, coordination or regulation is needed to give investors more certainty about the future revenues.

The concepts of perfectly functioning market and market failures can be used to formulate criteria for defining optimal regulation. We formulate the following criteria:

- When an activity causes external effects (negative or positive), regulation should focus on internalising these effects. The most efficient way to internalise these effects is to introduce prices (or tariffs, fees) that are efficient, which means that the prices reflect the marginal benefits and costs of the effects. This condition implies that if the regulator sets tariffs, for instance for the use of energy infrastructure, they should be related to the marginal costs of using that infrastructure.
- Markets may result in distorted prices if some market parties are able to influence market outcomes by acting strategically. Hence, another criterion is that no market party should be able to exercise market power.
- The rule that tariffs should be related to marginal costs is based on the allocative efficiency principle, but in the long term it is also crucial that the industry is dynamically efficient. Hence, it is also important that regulated firms are able to recoup their fixed costs and have incentives to put effort in lowering their marginal costs.
- Another criterion refers to the ability of market participants to engage in trade. In order to be able to do so, they need information on product characteristics and the outcomes of their transactions. A key condition for well-functioning markets is that market parties have the same symmetric information. If, for example, consumers do not have the same information on product quality as producers have, that market will result in suboptimal trade. If such information asymmetry exists, this should be addressed.
- Related to this point on information is the general criterion that transaction costs should be low, otherwise market parties will be hindered in making efficient deals.
- Market transactions may also become distorted if some parties can be held-up by others, which occurs in the case of dedicated investments. Parties will not make such investments if they do not have certainty before they make the investment decision on the revenues after the investment has been realised.
- The market process results in profits and the distribution of these profits (rents) can be an important consideration for regulators. Microeconomic theory is not typically used to formulate criteria for an optimal distribution of rents, as the assessment of distributional issues depends on society's preferences about what is fair and not fair. From behavioural economics, however, we can derive some general principles on fairness. One of these



principles, is that people/firms 'deserve' to receive rents when they have done something to generate them. Hence, windfall profits are generally seen as unfair.

- The above criteria are related to the functioning of markets. A specific criterion for the assessment of regulation is cost-effectiveness. This criterion says that the policy objectives should be realised at the lowest possible costs.

4.3. Theoretical economic criteria for assessing regulation of renewable gases and hydrogen

By combining the 5 categories of economic regulation from Section 4.1 with the fundamental economic criteria for optimal market interventions, we can formulate more concrete economic principles for the regulation of the markets for renewable gases and hydrogen (see Table 4.1).

Table 4.1 Principles of optimal economic regulation of renewable gases and hydrogen

Economic criteria	Categories of regulation				
	Policy targets	Certificates schemes	Access to the grid	Support schemes	
				Production support	Renewable energy obligations
Allocative efficiency: price=MC			Tariffs per unit equal marginal costs	Support = value of externality – value of other regulatory measures to internalise (e.g. carbon tax)	Imposed cost = value of externality – value of other regulatory measures to internalise (e.g. carbon tax, production support)
Dynamic efficiency: sufficient return on investments	Long-term policy commitments	Long-term transparency on certificate scheme	Total revenues from regulated tariffs should cover fixed costs of grid	Long-term certainty on support schemes	Long-term policy view on obligations
No market power			Third-party access, unbundling	In case of competitive tendering: many producers required	Retailers should have a choice among producers to buy renewable gas from
No information asymmetry		Increase trust of consumers in certificates by e.g. standardisation, public certifier	Capacity and tariffs should be clear to (potential) network users	Between Regulator-Producer: organise competitive tenders in case of many producers; otherwise smart incentive mechanisms, like menus, price caps	Between retailer-producer: traceability of green gas. Between regulator-retailer: learning by doing (learn from market prices about level of efficient obligations)
No hold-up			Network operators should have certainty about compensation of costs of connecting renewable gas	Governments should not be held-up after the support decision has been made	
Fair distribution			Fees should be related to actual costs producers cause + fees should be related to the actual usage of the network + common costs should be fairly allocated among network users	Support <= actual costs – other revenues	Price certificates <= actual costs – other revenues
Cost-effective	Lowest-cost options should be chosen first, both in short and long run.	Clear information on certificate about production characteristics	No discrimination among production technologies; only based on costs	Lowest-cost options should be chosen first	Lowest-cost options should be chosen first

5. Policy targets

5.1. Introduction

When addressing an environmental problem, there are two main issues. One is to determine a target indicating how much release of a particular pollutant we should allow. The second is to design incentive mechanisms to achieve the target at minimal cost.

Because pollution is a public bad, it may be argued that regulators should not allow any of it to occur. From an economic point of view, this does not make much sense. Since the work of Pigou (1920), the standard for setting environmental targets is economic efficiency. Obviously, the activities that generate pollution in an economy, e.g. heating and cooling, bring societal benefits as well as damages. Economic efficiency calls for the maximisation of all the benefits minus all the costs, which implies that polluting activities should continue to be allowed so long as the last unit of pollution generates a marginal benefit that is greater than the marginal damage. Thus, the maximum allowed level of a pollutant is such that marginal benefits and costs are equalised.

Because distinct pollutants have different associated levels of benefits and costs, it is reasonable to observe regulators entertaining an array of policy targets. However, for a particular pollutant, the notion of economic efficiency calls for a single target. For the case of carbon, it is well understood that efficient outcomes can be obtained with cap-and-trade schemes or carbon taxes. In theory, these systems tackle the carbon problem while maintaining technology neutrality. A sound carbon price makes low-carbon technologies more competitive, which fosters innovation in cleaner technologies. The carbon price signals the reward for emitting less and it is the market that picks the successful technologies. Although technology neutrality is commonly advocated in climate policy at the EU level, it is not so in practice and much less so at the Member State level. For example, the EU has a target for the share of renewable energy in final energy consumption, and encourages Member States to introduce support schemes to facilitate the integration of such energy sources into the energy system. Member States often set technology-specific targets.

5.2. Current Situation

In 2007, the European Commission put forward the Energy Policy for Europe, which is an integrated energy/climate plan addressing security of supply, climate change and industrial development. Through this Plan, the Member States jointly committed to increase energy efficiency by 20% relative to 1990 levels, to reduce GHG emissions by 20% compared to 1990 levels, to reach a share of renewable energy in final energy consumption of 20% and to arrive at a biofuel share in vehicle fuel of 10%. While these targets are at the European level, the Renewable Energy Directive 2009/28/EC establishes binding commitments for the Member States for renewable energy by 2020. As each Member State has distinct economic resources and its own specific energy market, the Directive sets different targets per country. Each country, in its National Renewable Energy Action Plan for 2020, shows the actions they will take to meet the 2020 renewable targets. The plan includes a description of the technologies to use, including sectoral targets, and the supporting policy measures.

Table 5.1 Current policy targets for renewable energy in number EU countries

2020 Target							
	Italy	France	Germany	Belgium	NL	UK	EU
% renewable heat in total heat	17,09	33	15,5	11,9	8,7	12	
% renewables in final electricity	26,39	27	38,6	20,9	37	31	
% renewable in transport	10,14	10,5	13,2	10,14	10,3	10,3	10
% overall RES in final energy consumption	17	23	19,6	13	14,5	15	20

Source: Renewable Energy Action Plans of the European Member States

Main goals beyond 2020

	Italy	France	Germany	Belgium	Netherlands	UK	EU
2030 % renewables in final electricity	55	40	40-60*	17**	-	-	
% overall RES in final energy cons.	30	32	30	20**	27-35	32	32
% renewable gas in gas consumption	-	10	-	-	-	-	
2050 % renewables in final electricity	-	-	80	-	-	-	
% overall RES in final energy cons.	-	-	-	-	100	-	100

Source: CEER Status Review of Renewable Support Schemes in Europe

*: 2025: 40 - 45% (gross electricity consumed); 2035: 55 - 60%.

** : 17% is off-shore wind; 20% excludes off-shore wind

Concretely, Table 5.1, drawing from the Renewable Energy Action Plans for 2020 of the European Member States, specifies targets for renewable heat and cooling, electricity and transport for the 6 countries being studied, namely IT, FR, DE, BE, NL and the UK. As the Table shows, the ambitions of the different countries are quite distinct, which can be explained in terms of the specificities of their energy markets as well as the various objectives and strategic choices of, and pressures exerted on, the corresponding governments. It is remarkable that, except in the case of France, the target for the overall share of renewable energy in final energy consumption is below the 20% ambition of the European Commission, with Germany very close and Belgium quite far off. The national plans also provide targets for the share of renewable energy in transport and the five countries are much more in line with the EU ambition, with Germany somewhat above. The national plans also specify targets for the share of renewable heat in total heat, and the share of renewable power in total electricity. It is worth mentioning that Germany and the Netherlands had targets close to 40% for the share of renewable power in total electricity by 2020.

The main goals for the EU after 2020 are specified in the recast of the Renewables Energy Directive 2018/2001/EU, which came into force in December 2018. In between, the Commission Communication of 22/01/2014 proposed an EU target for the share of renewable energy of 27%. This communication proposed to abolish targets for MSs and substitute it by a system in which each country delivers contributions to reach the joint target. This idea was further developed in the recast of the Renewables Energy Directive. In this Directive, the new binding share of renewable energy in final energy consumption for the EU by 2030 is set at 32%. The EU also has the ambition to become a carbon-free economy by 2050.



According to the regulation, by the end of 2019 Member States are required to draft definitive 10-year National Energy and Climate Plans (NCEPs) specifying their policies to meet the above target. To date, Member States have submitted their preliminary NCEPs. The country information regarding the main targets for 2030 and 2050 in Table 1 draws from these preliminary drafts. Except in the case of Belgium, all the countries have set targets for the share of renewable energy in final energy consumption ranging from 28% to 35%, which is in line with the EU directive.

It is remarkable that, except in the case of France, no country has set a target for the share of renewable gas in final gas consumption. France's ambition is that 10% of gas consumption by 2030 is renewable gas. By contrast, most countries have established targets for the share of renewable generation in total electricity production. These targets are quite ambitious in the case of Germany, reaching 60% by 2030 and 80% by 2050. The Netherlands has committed to a completely carbon-neutral economy by the same date.

5.3. Assessment of Regulation

As mentioned above, in its Energy and Climate Policy, the EU advocates for a policy of technology-free and sector-free targets, but in practice this is not entirely the case. The reason for such an approach is well grounded in economic theory. If one wishes to reduce the emissions of pollutants, a sensible policy is to set a target for carbon emissions and let the market decide which is the least costly way to achieve the target. Absent market imperfections, failures and considerations other than efficiency, imposing targets on renewable energy, renewable electricity or renewable gases are likely to create inefficiencies because the different technologies vary in the marginal cost of abatement and marginal damages.

Many Member States, however, have action plans where they set targets for specific technologies. As reported in Table 5.1, it is common that countries specify a target for renewable generation in final electricity production, and some countries' policies even set targets for wind and solar power.

There may be good reasons for setting targets for specific technologies (Azar and Sandén, 2011). One reason is that policymakers often have several objectives and not just economic efficiency. These objectives may include health, safety, inequality, security, and technological considerations. For instance, advocating for a completely technology neutral climate policy may result in an expansion of nuclear energy, with important repercussions on safety not reflected in the carbon price. Another reason is that, in general, it will be hard for policymakers to estimate the marginal costs of pollution abatement, which equal the marginal benefits forgone for not polluting, and in some sectors these costs may be estimated with much more uncertainty than in others. If, for example, the marginal damages of some technologies are systematically under-estimated then targets may be set far too low for some technologies that would enter the market otherwise. In those cases, it may be advisable to set sectoral targets and consistent, supporting environmental policies. Correspondingly, many EU countries have imposed sectoral targets such as those for the share of renewable generation in final electricity consumption or on the share of wind, solar or biomass power generation in renewable electricity.

A variety of market failures may also justify the use of sectoral targets. For example, the existence of short-run rigidities such as substantial entry costs combined with network effects may result in inefficient long-run technology adoption. In fact, technologies with significant potential to lower costs in the long-run because of scale economies and 'learning by doing' effects may have difficulties in entering the market due to relatively large fixed costs compared to other technologies. If, in addition, network effects unfold as it is commonly the case in network industries, the economy may become locked into an undesirable set of technologies and, as a



result, technologies that are currently expensive but more favourable in the long-run may never make it to the market.

Financial market imperfections and myopia may also make it difficult for less-developed but high-potential technologies to get support and enter the market. This is because large and established firms often access funding more easily than small and new firms. Sectoral targets may provide investors with the necessary certainty to avoid these imperfections resulting in the market picking the 'wrong winner.'

As in the case of important infrastructure such as railroads or gas pipelines, sectoral targets are a way to show governmental commitment to a particular vision, or strategy, which facilitates the oftentimes difficult coordination of multiple economic and social actors. In fact, such coordination may be difficult to achieve without changes in the law and the set of regulations.

Last but not least, another reason why policymakers may opt for sectoral policies rather than technological neutrality is that policymaking is not immune from political pressure and sectoral lobbying activity.

5.4. Recommendations

Our recommendations are based on the view outlined in Table 4.1 that policy targets are key long-term commitments; moreover, we believe that lowest-cost options should come to the market first.

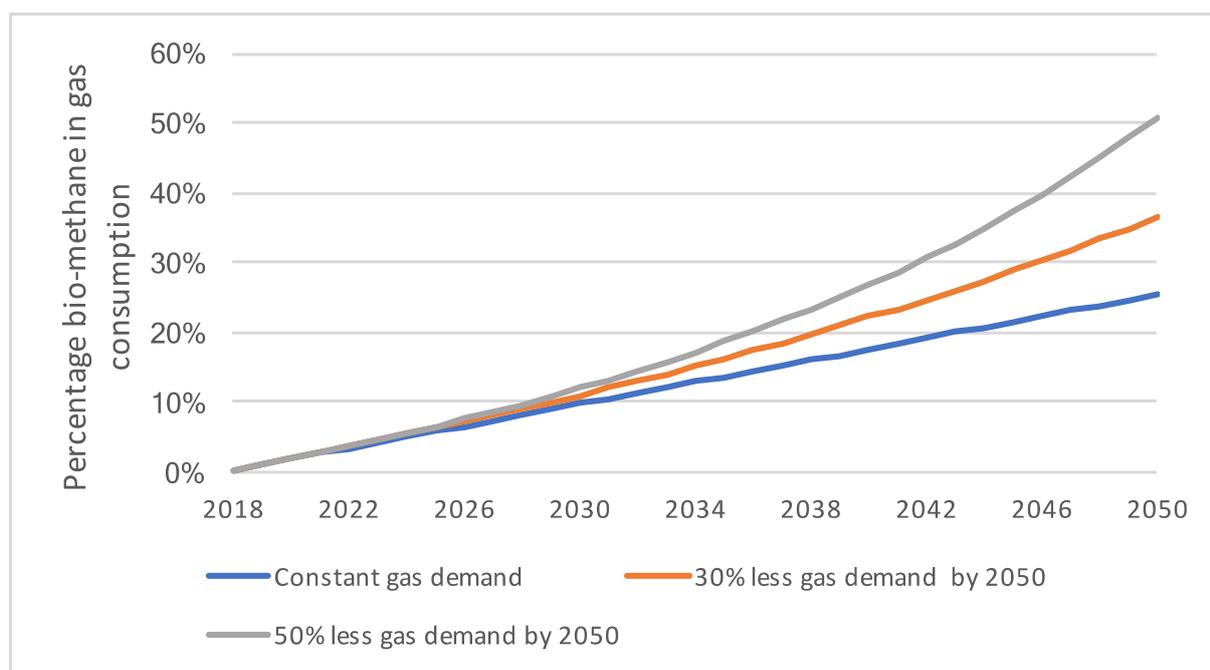
It would be desirable that Member States set targets for the gradual replacement of natural gas by bio-methane and the replacement of existing hydrogen by carbon neutral hydrogen. It should be noted that, during an energy transition, it is expected that governments make sure all technologies have an opportunity to provide creative solutions. Currently, however, the playing field is not truly levelled for renewable gases and hydrogen. As we have seen, given the current costs of production, and given that the carbon price does not fully reflect the externalities, these technologies have difficulties in entering the market. Moreover, until now there has been a clear focus on renewable electricity and the existence in many Member States of targets and support for renewable electricity has made the playing field even more uneven. It is advisable that this issue is corrected. Currently expensive technologies such as thermal gasification or electrolysis may otherwise not gain enough development so as to unfold the cost cuts associated with economies of scale and the dynamics of learning by using.

Our study has derived a potential to supply 75 bcm of bio-methane annually for the countries studied, and 124 bcm for the EU-28 as a whole. The former represents about 20% of the current consumption of natural gas in BE, DE, FR, IT, NL and UK; the latter represents about 25% of the EU-28 consumption of natural gas. Assuming the demand for natural gas remains constant from now until 2050, we recommend an EU-28 target of 10% of bio-methane for 2030, and a 25% target of bio-methane for 2050 (Figure 5.1). To reach such a potential by 2050, the market share of bio-methane should increase by slightly over 1 percentage point per year. Arguably, the demand for natural gas might decline from now till 2050. Assuming that the demand for natural gas will be 30% lower by 2050, reaching the full potential of bio-methane requires a target of 35% of future gas demand by 2050. If natural gas demand instead falls by 50% by 2050, this target should then be set at around 50% (see Figure 5.1).

Gas demand is expected to decline but the extent to which it will diminish is uncertain. This calls for a policy of target adaptation. New legislative proposals should also consider an assessment of EU-wide and national markets progress by 2028 against the 2030 target. A report explaining the main development of the markets for renewable gases should help to better enforce targets between 2030-2050. Such progress reports should guide the European Commission to review and

make recommendations per Member State in the design and submission of National Energy and Climate Plans.

Figure 5.1 Proposed EU-28 targets for bio-methane, in % of EU-28 gas consumption, for 3 scenarios



Source: Authors' own work

Regarding hydrogen, as argued in Chapter 3, we expect excess renewable electricity to remain scarce, which implies that there will not be many hours of low electricity prices. Therefore, unless major cost cuts are realised in the electrolysis process, we believe that the bulk of the CO₂ neutral hydrogen produced by 2050 will be sourced from natural gas via SMR combined with CCS. Given that, conditional on the public acceptance of CCS, the production of NG-sourced H₂ is not really constrained, we propose a target of 100% carbon neutral hydrogen by 2050. We also strongly believe that such a target for natural gas-sourced hydrogen will act as an instrument to foster the social acceptance of CCS.

We further note that the development of renewable electricity-sourced hydrogen is intimately linked to the likelihood of many hours of low electricity prices. Therefore, any specific target for this type of hydrogen should be consistent with the targets for renewable electricity as well as the European policies to promote electrification. We therefore recommend against the introduction of specific binding targets for RE-sourced H₂ in the same renewable gases legislative piece.

6. Certificates

6.1. Introduction

When a renewable gas is injected into the gas grid, it needs to have the same physical qualities as natural gas.⁹ Hence, physically, renewable gas within the grid cannot be distinguished from natural gas. The same applies for hydrogen: when it is injected into a physical network the source of hydrogen cannot be seen anymore. This gives rise to the classic market failure of information asymmetry: consumers do not have the same information as producers. In the absence of regulation, producers of renewable gas are not able to obtain a premium for the 'greenness' of their gas as their customers cannot be sure that the gas they extract from the gas network is truly produced in a green way. This information asymmetry results in so-called 'adverse selection', with the result that products of higher quality and higher production costs (in this case, renewable gases) do not get a sufficient remuneration and leave (or do not enter) the market.

The regulatory approach to solve this market failure is the creation of certificates. In general, certificates are proof that something (a commodity or a process) meets certain criteria. In the case of green energy, the certificates provide hard evidence that the energy is produced in a specific (renewable) way.¹⁰ The certificates can be based on voluntary initiatives or legal commitments. For electricity, there is the official European system of guarantees-of-origin (GOs) based on EU Directive (2009/28/EC). All EU Member States must have a GOs system for electricity. The issuance, trade and cancellation of certificates are standardised through the European Energy Certificate System (EECS), which is organised by the Association of Issuing Bodies (AIB). For gas, however, there is no such standardised European system. Member Countries have various national systems which are only partly interconnected. These gas certificate systems are based on voluntary agreements.¹¹

Another difference between the certificate systems in electricity and gas markets is that the former are solely based on the so-called book-and-claim approach, while the systems in the gas market rely on the mass-balancing approach for international trade. Under the book-and-claim system of the electricity market, there is no connection between the physical trade of the underlying commodity and the trade of the certificates. The trade of green-electricity certificates is not constrained by restrictions within the electricity network as they don't play any role. As a result, for instance, Norway may export amounts of green-electricity certificates to Germany and Netherlands that significantly exceed the capacity of the respective cross-border interconnections; likewise, Iceland may export certificates to the continent in the absence of any power interconnection.

Under the mass-balancing approach, by contrast, the transaction flows of the certificates remains connected to the physical flows of the underlying energy commodity. This approach is used in the gas market because of the European Renewable Energy Directive and the Fuel Quality Directive, which only recognise international trade in certified liquid and gaseous biofuels when the physical transfer is coupled to the trade in the certificates. Consequently, international trade of renewable gas certificates can only be done between countries for which a physical connection exists. In addition, when green-gas certificates are used to make transport fuels green, the certificates

⁹ These physical qualities refer to percentages of methane and nitrogen. As the required percentages are within a range, these qualities are described as specs.

¹⁰ It is important to distinguish certificates and labels. The latter are claims made by producers, traders or retailers which are not necessarily (fully) based on certificates.

¹¹ In this report, we use the term 'green certificates' as the general term for proofs that an energy product is produced in a renewable way. A subgroup of certificates are, for instance, guarantees of origin, which are green certificates based on European regulation or international agreements. See, for instance, the website of the Dutch certifier CertiQ (<http://www.certiq.nl/en/we-are/types-of-certificates/>) where this approach is also used.

should be linked to the mass-balancing approach. For domestic systems, however, it is possible to have book-and-claim systems in the gas market without mass balancing.

In this chapter we briefly describe the current renewable gas certificates systems in a number of European countries (Section 6.2) before presenting our assessment (Section 6.3).

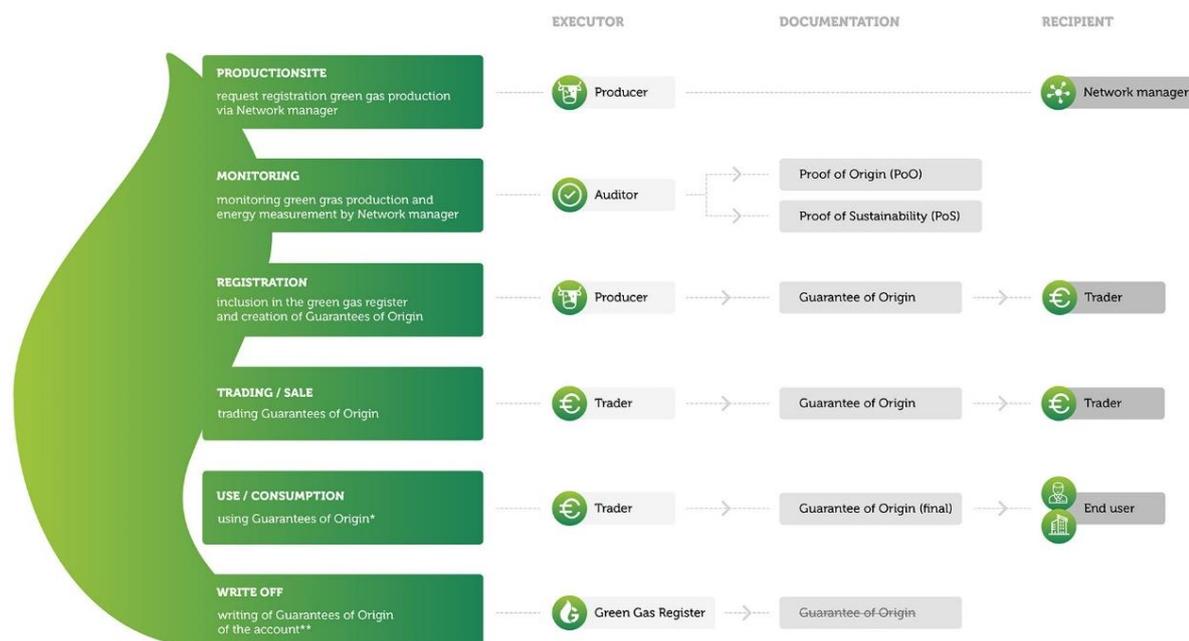
6.2. Current situation

6.2.1. Belgium

The Belgian system of green certificates is operated by Green Gas Register, which is an independent organisation, not active in the production or trade of renewable gas, but its partners are two Belgian gas network operators (Fluxys and Fluvius). The Belgian process is depicted in Figure 6.1. The producer injects the gas into the grid and sells the gas to traders. When the green-gas producer has received a proof of origin and a proof of sustainability of the green-gas production, it receives a Guarantee of Origin, which can be sold to traders. The traders may trade these GOs with one another before selling them to end-users who want to consume renewable gas. When gas is sold as renewable gas to end-users, the GOs are cancelled.

In Belgium, the green-gas certificate scheme is not connected to the European emissions trading scheme. Hence, the certificates cannot be converted into other renewable-energy units as it is possible in, for instance, Denmark, the Netherlands and the United Kingdom.¹²

Figure 6.1 The Belgian scheme of green certificates



* The total value of the Guarantees of Origin used, corresponds to the energy value of the gas purchased by the end user.

** By removing used Guarantees of Origin from the market, the green gas register guarantees that no more green gas can be used than has been produced.

Source: <https://www.greengasregister.be/en/guarantee>

¹² The EU Renewable Energy Directive gives EU member states the option to do this, but they are not obliged to implement this option.

6.2.2. Germany

The German renewable gas certificates system is managed by the Deutsche Energie Agentur (DENA), which operates the platform for standardised verification, the so-called Biogas Register.¹³

The verification process consists of the following stages:

1. Producers feed renewable gas into the natural gas grid.
2. The Biogas Register keeps accounts of quality and quantity of the renewable gas injected.
3. Certification of quality and quantity by third-party auditor.
4. Producers and traders can split and trade quantities of renewable gas in accordance
5. Consumers receive individual guarantees of origin and quality for the quantities withdrawn.

Producers can use the certificates to receive the feed-in tariff from the network operator.

The DENA certificates can be traded across the border with the Netherlands and Denmark, through cooperation with Vertogas and Energinet.

6.2.3. Italy¹⁴

The Italian scheme for green-gas certificates is coupled to the financial incentive scheme.

The current Italian scheme on bio-methane distinguishes two main categories:

- Bio-methane injected into the natural gas grid without a specific intended use, which receives a Guarantee of Origin.
- Bio-methane injected into the natural gas grid to be used in the transport sector. The program distinguishes between bio-methane and advanced bio-methane, the latter referring to bio-methane from waste, and sustainable feedstock in general that does not cause any direct or indirect change in the use of land. Bio-methane producers obtain from GSE (Gestore dei Servizi Energetici, which is responsible for managing the renewable incentives) a certificate called "Certificati di Immissione in Consumo di biocarburanti (CIC)" per 11.16 MWh of non-advanced biomethane injected into the grid, and for 5.8 MWh of advanced bio-methane injected into the grid. These certificates are in turn sold to the fuel suppliers, who are subject to a biofuel annual quota. In 2018, this quota was 7% for biofuels, and further required 0.45% of bio-methane. From 2022, the quota will be 9%, and the bio-methane share 1.39%. A quantity of advanced biomethane up to the annual target can be sold through the GSE. The GSE remunerates it based on the monthly average spot price for gas minus 5% and also withdraws the CIC at a price of €375, which it charges to the fuel suppliers. Producers of advanced biomethane can benefit from this system for 10 years.

6.2.4. France

The French system of renewable gas certificates is operated by GRDF. A particular characteristic of the French system is that certificate trading is not possible. Only producers and suppliers to end-users may exchange the certificates.

The GRDF certificates are mainly used in the transport sector (70%) and by municipalities (18%). The high share of the transport sector results from special regulation: when a supplier sells

¹³ See <https://www.biogasregister.de>

¹⁴ This section on the IEA country report on Italy: Italy – 2018 update, Bioenergy policies and status of implementation

certificates to a user from the transport sector, it may keep all revenues, but when the certificates are sold to other types of users (for example from the heating sector), the supplier must transfer 75% of the revenues to the Government. This amount is transferred to a governmental fund for energy transition that is partly used to finance renewable gas plant projects.

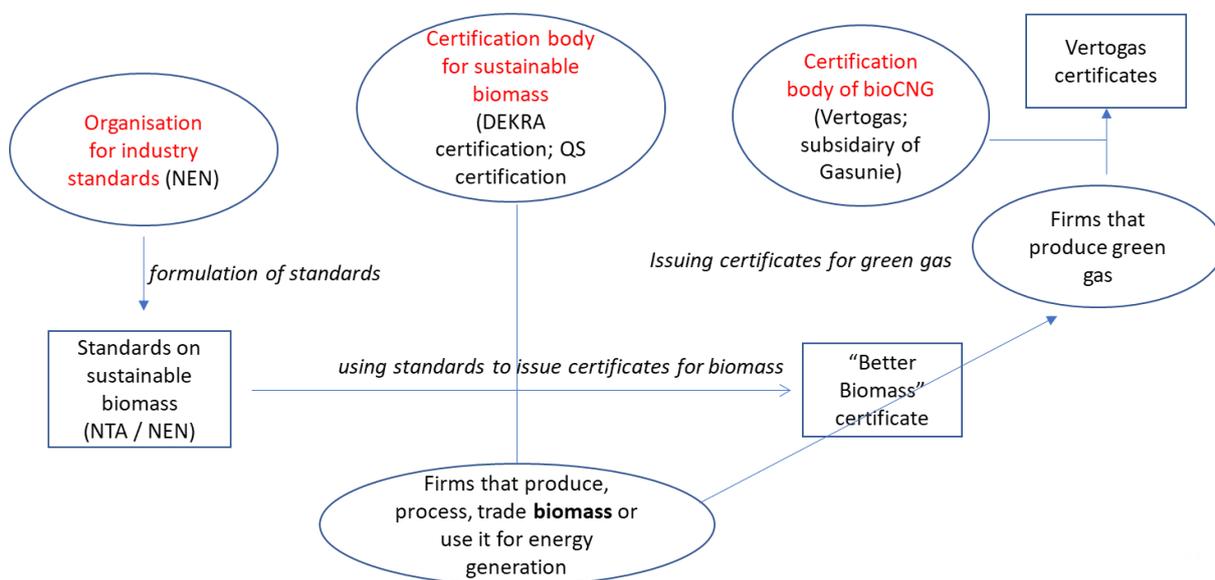
6.2.5. The Netherlands

The Dutch certification process consists of three stages (see Figure 6.1). The first stage is the definition of standards for sustainable biomass. These standards are expressed in the Netherlands Technical Agreements (NTA) 8080, which are related to the requirements laid down by the European Commission (Directive 2009/29/EC). NTAs are voluntary agreements as opposed to NEN standards which hold industry wide. Both types of standards are set by the Organisation for Industry Standards (NEN).¹⁵

The second stage of the certification process is the assessment of firms that produce, process or trade biomass. When these activities are done on the basis of NTA 8080 products, the firms can then obtain the "Better Biomass Certificate" issued by one of the two certifiers: DEKRA certification and QS certification.

The third and last step in the certification process of renewable gas is carried out by Vertogas. This subsidiary of Gasunie has the legal task to operate the Dutch renewable gas certificates system. Firms that produce renewable gas based on the Better Biomass Certificate receive the so-called Vertogas certificates.

Figure 6.1 The Dutch certification system



Source: Author's own elaborations

A Vertogas certificate refers to 1 MWh of gas and states that this gas has been produced from sustainable sources and the gas has the same physical characteristics as natural gas. The

¹⁵ NTAs are based on agreements between relevant stakeholders: the agreement is public, but not all participants need to adhere to it (no consensus required). In contrast, for a NEN, consensus is required: all relevant stakeholders must support it, which generally requires a longer period of consultations, discussions etc. before a NEN can be agreed upon.



certificates can be used to sell renewable gas to end users while they also form the basis for support (SDE+) and green energy certificates (HBE).

Producers and their installations need to be registered at Vertogas, and the producers need also to inform Vertogas about which type of biomass will be used. The installations also require registration with the network operator. On a monthly basis the injection of renewable gas into the network is registered, which is the basis for the issuance of the certificates.

The producers can sell the certificates to traders or end-users, but they may also use them for creating Renewable Fuel Units (HBEs), but in the latter the producer is no longer eligible for production support through the SDE+ in order to prevent double support.¹⁶

Traders also need to register with Vertogas in order to get an account for certificates. Traders are defined as all those agents who possess certificates. In principle traders have three options:

- Enter into bilateral agreements with producers so that all renewable gas production is allocated to the trader: in such a case, Vertogas adds the corresponding certificates to the account of the traders on a monthly basis.
- Exchange with other traders: in this case, Vertogas only updates the accounts (but is not involved in the deals).
- Sell renewable gas to end users: here certificates are cancelled by Vertogas.
- Transfer the certificates into Renewable Fuel Units (HBEs).

Users are defined as agents who use the certificates for their own consumption. Users are also required to register with Vertogas (free of charge) and to report the identity of the trader(s) from whom it will buy certificates. These certificates will be cancelled by Vertogas.

The current market size is still small: in 2018 the total size was 0.12 bcm, while the total Dutch natural gas consumption was about 40 bcm.

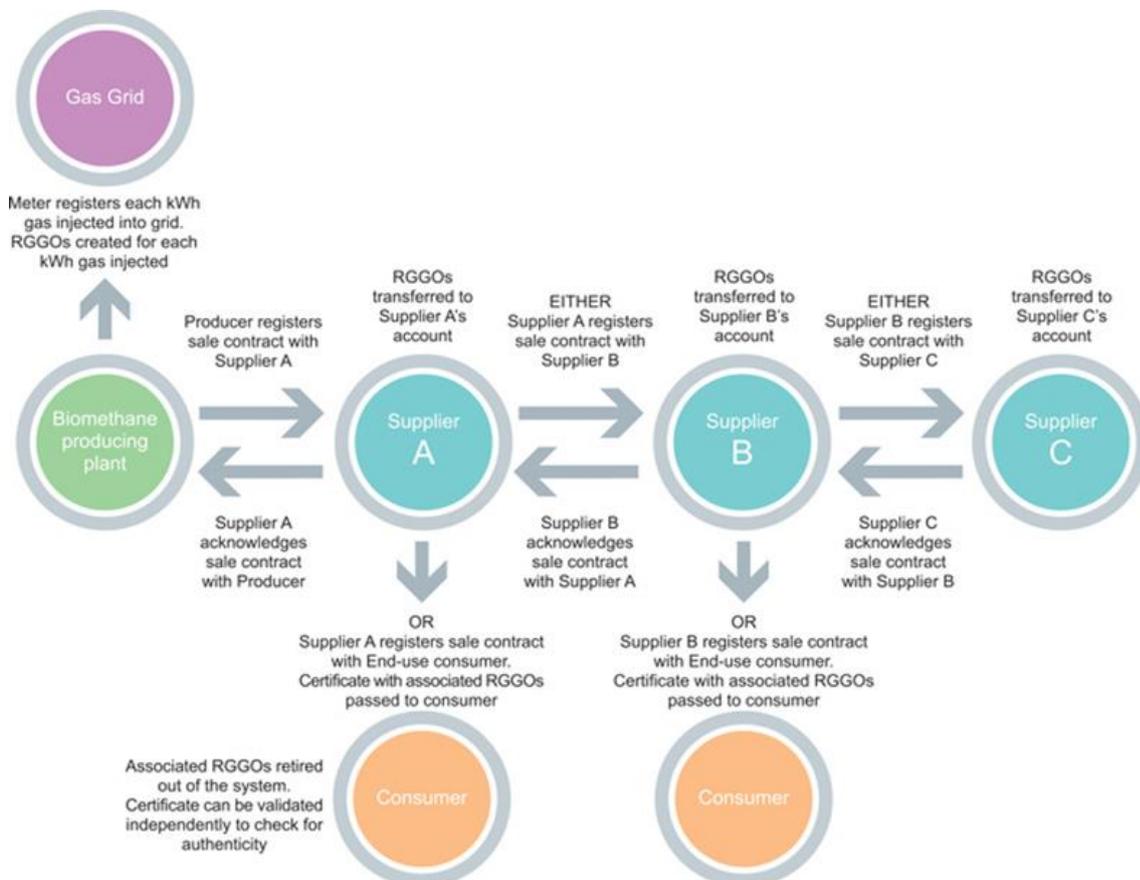
6.2.6. United Kingdom

The UK system of renewable gas certificates, which is called the Green Gas Certification Scheme (GGCS), is operated by Renewable Energy Assurance Ltd., which is a subsidiary of the Renewable Energy Association (REA) (representing British renewable energy producers). The GGCS tracks the commercial flows of each unit of renewable gas from its injection into the distribution grid to its sale to end-users (see Figure 6.2 for the UK certification process).

In order to be able to receive the renewable gas certificates, the production process should be based on renewable energy. Renewable gas producers, therefore, may apply for the so-called Biofertiliser Certification Scheme (BCS), which indicates that the anaerobic digestion plant is verified on the basis of the PAS 110 and Quality Protocol. This means that the digestate produced at the plant as a result of the process can be classified as a product rather than a waste and that it can be used as a carbon-free fertilizer on crops.

¹⁶ The system of HBEs is organized by the Netherlands Emissions Authority (NEa). The HBEs can be used by the Dutch transport sector to meet obligatory targets regarding renewable energy. Currently this target is 8.5%, but this will almost double to 16.4%. One HBE is equal to 1 GJ of renewable energy, but the market value depends on the type of energy used. As biofuel based on NTA 8080 certificates count double, the market price for green gas certificates has increased significantly up to the current market price of about 0.50 €/m³.

Figure 6.2 Certification process in the United Kingdom



Source: <https://www.greengas.org.uk/>

The use of landfill gas and biogas for producing renewable gas has increased in recent years. Until a few years ago, these inputs were mainly used to generate electricity, supported by the Renewables Obligation (RO). As a result of the EU target for renewable heat and renewable fuel in transport, UK producers moved to use these inputs for making renewable gas and inject the gas directly into the gas distribution network.

6.2.7. International cooperation

Although there is not yet a European registration system for renewable gas certificates, Member States' systems are becoming increasingly connected. The international cooperation with the EU is facilitated by the ERGaR: the European Renewable Gas Registry, which is a cooperation between national renewable gas registries in Europe. This cooperation is meant to facilitate cross border trade of renewable gas certificates among the member registries. Due to European regulation (see Section 6.1), this trade remains based on the mass balancing of renewable gas distributed along the European natural gas network.¹⁷

This cooperation results in European Guarantees of Origin (EGOs), which include information on various aspects which are deemed useful for consumers in the importing countries. The

¹⁷ See: <http://www.ergar.org/>; members include Vertogas, GRDF, EnergiNet, gas.be, DENA, etc.

requirements for EGOs are that the injection into the European gas network has been duly confirmed while at the same time the consignment has not been taken into account in the country of production for the purposes of a) measuring compliance with the requirements of the RED concerning national targets, b) measuring compliance with renewable energy obligations or c) eligibility for financial support for the consumption of biofuels.

6.3. Assessment of regulation

The issue of asymmetric information between producers of renewable gases and consumers is resolved via a certification system. Lacking a way to trace the environmental friendliness of the gases, it is not possible to transfer rents directly from the (environmentally conscious) consumers to the producers via the market mechanism. This is the so-called adverse selection problem, which leads to a market situation where good gases are underprovided. All countries have certificates for renewable electricity, as stipulated by the EU, but renewable gases certificates have been introduced in only a few of them. Because certificates enable the tracing of renewable gases, they facilitate the subsidisation process. When, in addition, these certificates are traded, they provide additional sources of income for producers and therefore subsidies need not be that large. Moreover, when the certification scheme is transparent and based on a clear and constant regulation, it also improves dynamic efficiency and cost-reflectiveness in the market for green gases.

As the green certificates system in the electricity system is more mature than the system in the gas sector, we look at the experiences in these sectors to draw conclusions on the effectiveness and efficiency of the design. In an empirical analysis of the green certificates market in the electricity market, Hulshof et al. (2019) conclude that two factors are important for a well-functioning certificates market: international standardisation and public ownership.

Table 6.1: Design characteristics of national GO certification schemes

	Implementation of international standard	Nature certifier	Export restrictions	Certification restrictions
Austria	2004	Public	Yes	No
Belgium	2006	Public	No	No
Cyprus	2014	Public	No	No
Croatia	2014	Public	No	Yes
Czech Republic	2013	Private (2013-current)	No	No
Denmark	2004	Public	No	No
Estonia	2010	Public	No	No
Finland	2001	Public	No	No
France	2013	Private (2013-current)	No	Yes
Germany	2013	Public	No	Yes
Iceland	2011	Public	No	No
Ireland	2015	Public	No	Yes
Italy	2013	Public	No	No
Luxembourg	2009	Public	No	Yes
Netherlands	2004	Public	No	No
Norway	2006	Public	No	No
Portugal	Not implemented	Private (2013-2015)	No	No
Spain	2016	Public	Yes	No
Sweden	2006	Public	No	No

Switzerland	2009	Public	No	No
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Source: Hulshof et al. (2019)

Although European regulation prescribes that Member States need to have a certification scheme, they have some freedom to determine the precise design of the scheme. As a result, countries have made different choices, in particular regarding the market design and ownership of the certifier (see Table 6.1). Hulshof et al. (2019) find that in markets where the certificates are based on international standards, the liquidity of the market is significantly higher than in markets where the certificates are based on national standards. The underlying mechanism is that international standards facilitate international trade and, hence, the options for traders to buy and sell certificates. In addition, public ownership seems to affect the trust market participants have in the certificates system, as in markets where the certifier is publicly owned the liquidity of the market is higher. Hulshof et al. (2019) also conclude that the green-certificates system in the electricity market, despite the many years of experience, cannot be viewed as mature. The liquidity of the market is still fairly low, reflected in the fairly low churn rates. Despite this low liquidity, international trade in green-electricity certificates has become more important. In the Netherlands, for instance, the total import of green certificates has increased to about 1/3 of total Dutch electricity consumption (CertiQ, 2018).

6.4. Recommendations

Based on the above analysis, we formulate the following conclusions:

- International standardisation of the sustainable character of the gases helps foster the market, as this increases the trust of market participants in the value of the certificates. Further integrating national systems by making use of international standards, therefore, will facilitate the future development of the system.
- The same holds for having a certifying agency that is in public hands instead of an agency that is owned and operated by private companies. In various countries, the certification process is run by market parties, which may hinder the trust of consumers in the certification. It is therefore recommended that the role of public authorities in the certification process be increased.
- Compared to the scheme in the electricity markets, the scheme in the gas market is significantly less transparent. In only a few countries is the functioning of the registration completely described on the website of the registering party, while hardly any information can be found on the trade itself (volumes, prices). In addition, the neutrality between using biogas for electricity and production of biomethane to be injected into the natural gas grid is not ensured. Improving the transparency of how the systems for green certificates are organised and how market parties can trade will give the scheme further impetus.
- A specific feature of the certificates system in the gas market is the mass-balancing approach. This means that for international trade and for the use of the certificates in the transport sector, the exchange of the certificates needs to be connected to the flows of the physical commodity. This approach is meant to prevent double counting of the renewable gas, but it also restricts international trade as certificates can only be traded if there is a connection with physical exchange of gas in the same network region (see CertifHy, 2015). Therefore, it is recommended that the need for the mass-balancing approach be reconsidered, and that the possibility to move more strongly in the direction of a book-and-claim approach for international trade in renewable gas be explored.

7. Grid access

7.1. Introduction

Almost all gas transport on the European mainland is done through pipelines. Due to the high capital costs of constructing a pipeline, together with the exponential increase in capacity with diameter, gas transport is dominated by natural monopolies per region. Without regulation, this monopoly would lead to inefficient high prices for the usage of this system. Since natural gas is a crucial element in the energy mix of Europe, the transport of natural gas is regulated in all European countries. All countries have a national regulatory authority that makes rules for the network operator. The regulatory authority monitors network operators' compliance with these rules and intervenes when necessary.

The responsibility of the network operator concerns the safety and stability of the network, as well as keeping the pressure in the grid at a certain level, by optimal steering of gas flows. Another crucial element the network operator is responsible for is the accessibility of the grid for all suppliers at the same conditions. This so-called third-party access (TPA) is key for a competitive gas market. To ensure this, the network operator is bound to rules regarding the connection of gas suppliers to the natural gas grid. In this chapter we analyse different aspects of regulation on gas grid access. Specifically, we analyse: the tariff structure for feeding gas into the network, the division of the costs for connecting a gas supplier to the gas grid, the responsibility for the quality of the gas injected into the grid and possible other country-specific regulation regarding injection of renewable gases into the gas grid.

Furthermore, since renewable gas, and maybe in a later stage hydrogen, makes use of this natural gas grid, we also look at how the grid access for bio-methane producers is regulated in different countries. Therefore, besides the regulation on grid access for gas suppliers, we also look at measures that are especially targeted at the producers of bio-methane or hydrogen. In section 7.2, we describe the current situation of the regulation for gas grid access and the special cases for bio-methane producers. In section 7.3, we will analyse the current regulation on grid access.

7.2. Current situation

The natural gas grids consist of a high-pressure transmission and a lower-pressure distribution network. Production, storage and industrial users are connected to the transmission grid, while small(er) consumers, such as households, are connected to the distribution network. Since the quantities of producers of bio-methane are not that large, it is possible for them to inject their gas into the distribution network, which is already done in the Germany, France, Ireland, Spain, United Kingdom and increasingly in parts of Italy. In the other countries, gas is supplied into the transmission network. Therefore, in some countries the producers of bio-methane are under the same legislation as other producers of gas and have to pay the transmission system operator (TSO), while in other countries producers pay the distribution system operator (DSO).

7.2.1. Tariff structure according to European regulation

For a (renewable) gas producer to be able to inject his product into the grid, he has to get access to the capacity from the network operator. The financial compensation for using this capacity is called the transmission or distribution tariff and is determined by the TSO. Thus, the tariff calculation is determined on a national level. However, to stimulate uniformity and transparency in



the EU, EU Regulation 460/2017 was developed. In this 'network code on tariffs' the methodology used to calculate the transmission tariffs was harmonised. Since the introduction of Regulation (EC) No 715/2009, entry and exit capacity can be contracted separately from the transmission tariff. Hence, transmission costs are no longer coupled to a specific route, allowing the TSO to efficiently direct the gas flow through the network. The newest regulation, (EC) 460/2017, proposes the reference price methodology to determine transmission tariffs in a transparent way (see Box 7.1). In the regulation, there is no specific mention of renewable gases and the tariff regulation proposed for that. Thus, according to European regulation, the tariff structure for renewable gases should be treated equally as other (natural) gases. Effectively, this means that the European regulation does not allow TSO's to charge different tariffs for renewable gases, due to non-discriminatory issues.

Box 7.1 Reference price methodology

With the implementation of the reference price methodology (RPM), a reference price is provided for all entry and exit points in a given system. The reference prices form the so-called reserve prices for the capacity tariffs which are used in the auctions of network capacity. The reference prices can only be adjusted at entry points from and exit points to storage facilities and at entry points from LNG facilities because of the potential benefits of these facilities for the network utilisation.

According to regulation (EC) 460/2017 the application of the reference price methodology can only be altered as a result of one or more of the following:

- (a) benchmarking by the national regulatory authority, whereby reference prices at a given entry or exit point are adjusted so that the resulting values meet the competitive level of reference prices;
- (b) equalisation by the transmission system operator(s) or the national regulatory authority, as decided by the national regulatory authority, whereby the same reference price is applied to some or all points within a homogeneous group of points;
- (c) rescaling by the transmission system operator(s) or the national regulatory authority, as decided by the national regulatory authority, whereby the reference prices at all entry or all exit points, or both, are adjusted either by multiplying their values by a constant or by adding to or subtracting from their values a constant.

An example - the Dutch case

In the Netherlands, the tariff structure is based on the annual tariff for a period of 12 months, which can start in every month. This annual tariff is published as entry- and exit-tariffs that differ among entry- and exit-points. There are 3 different types of entry points (border, production and storage) and 6 different types of exit points (border, industrial, closed distribution, local distribution, production, storage). All these different types have several unique points which all have their own entry or exit tariff. On top of that lies some general costs for balancing and maintaining the grid, which is equal for all points. The Dutch TSO, Gasunie Transport Services, publish all these annual tariffs on their website.

The tariff for a contract for a period less than 12 months is based on the annual tariff, but can be concluded for a few hours, a single day, a single month or several days or months. A monthly contract always stops on the last day of that calendar month. The capacity is booked by a shipper, who is a party that is recognised by the TSO and consequently has programme responsibility.

When the shipper books capacity for less than a year, the annual tariff is used in combination with the monthly factors to calculate the tariff. This factor differs among months and is a percentage of the annual tariff. The monthly factors can be found in Figure 7.1. The percentage is based on the demand in that given month, resulting in higher percentages and thus monthly factors in the winter months.

Figure 7.1 Monthly factors used by the Dutch TSO

	Months	Monthly factor percentage of annual tariff
Forward	Winter months	January, February, December 30%
	Shoulder months	March, April, October, November 15%
	Summer months	May to September 7,5%
	Backhaul	January to December 8,33%

Source: Gasunie Transport Services (GTS)

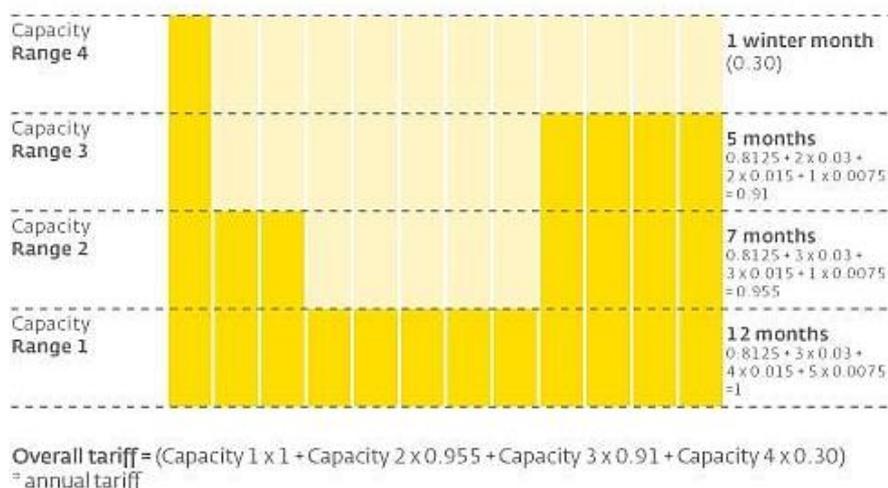
The calculation of the tariff for a period of less than a year is as follows:

- The sum of the monthly factors for the individual months (which can never exceed 100%) is multiplied by the annual tariff, or, if this is lower, (81.25% + 3% of the number of winter months + 1.5% of the number of shoulder months + 0.75% of the number of summer months) multiplied by the annual tariff.

In this way, a shipper can also book capacity for a year and extra capacity for a shorter period on top of that. If such a combined booking is done on the same day, for the same point and for the same direction the capacity is divided into horizontal capacity ranges and the monthly factor system is applied to each individual range. See Figure 7.2 for an example.

Figure 7.2 Tariff calculation for different booking periods

Example: tariff calculation profiled booking





Source: Gasunie Transport Services (GTS)

A different approach – the German case

The German tariff structure differs somewhat from the Dutch case. As mentioned in chapter 3, the German government has subsidised renewable gases for quite some years. With the new European legislation, the German regulatory authority, Bundesnetzagentur, had to re-evaluate their tariff methodology. In their decision on implementation, they envisioned that for renewable gases “no capacities shall be taken into account and no entry tariffs will be charged”. Effectively, this meant that the costs for feeding in bio-methane in the national gas grid are not burdened by the producer. Instead, the regulatory authority decided to levy these costs onto all end customers (industrial and households).

To check whether member states followed the European regulation, the European regulatory body, ACER, had to assess all the tariff methodologies in the member states. For Germany, the agency noted that the entry tariffs for renewable gases was proposed to be set at zero. In their assessment, they stated that they understand the rationale of a subsidy for renewable gases. However, they also point out the fact that under EU Regulation 460/2017 this approach is not allowed, because the RPM should be applied to all points of the network, regardless of the type of gas. Therefore, ACER asked the German regulatory authority to support renewable gases in a different way than with a differentiated entry tariff for renewable gases.

Other countries are expected to follow the same tariff methodology, without a discount for bio-methane producers, since this is not allowed by European regulation.

7.2.2. Connection costs

Besides the tariff, the physical connection to the transmission grid has to be constructed and paid. There is no European regulation on this matter, so countries can freely implement their own regulation. Below we provide an overview of the regulation found on the division of the connection costs per country.

Germany

In Germany the connection costs for all the suppliers of natural gas are divided between network operator and supplier. The system operator (TSO) has to bear 75% of the costs for connecting the facility to the grid and the connection taker (supplier) the other 25%. When the connecting pipeline is < 1 kilometre in length, the share to be paid by the connection taker is capped at €250,000. If the connecting pipeline exceeds 10 kilometres in length, the connection taker has to pay for the additional costs. Finally, if other connection takers at a later point in time connect to the same connection, there is the possibility for a partial refund.

However, as mentioned earlier, Germany has a long history in subsidising renewable gases. This is also the case with the connection costs that are not paid by the facility operators, but are socialised among all end users of the natural gas grid.

Italy

The Italian regulation regarding the connection of bio-methane plants is noteworthy. The costs of connection paid by the producer are based on 80% of the difference between the costs associated with the connection of the facility minus the expected discounted income for the network operator



coming from the tariff charged on the producer (considering a lifetime of 50 years). This regulation is the same for the connection of natural gas producers.

France

In France, the DSO pays 10% of the costs for the connection of a bio-methane plant. The rest of the costs are paid by the producer of the gas, which has to be done in one shot. To stimulate renewable gases, these connection costs are covered by Feed-In-Tariffs, as will be discussed in Chapter 8.

The Netherlands

In the Netherlands, the connection costs for bio-methane plants are completely equal to that of another (natural) gas supplier. With the current regulation, the network operator only offers a connection point to the supplier of the gas. The costs for the pipeline connection from the production facility to this connection point in the grid are paid by the producer.

Under the new law 'Voortgang Energietransitie' (01-01-2020), the network operator has to offer a connection (instead of only a connection point). This means that in future, both the cost for the connection point and the pipeline connecting the producer are paid for by the network operator. The costs are billed by transport fees to the shipping parties.

United Kingdom

In the United Kingdom, almost all connections are to the lower-pressure or medium-pressure grid. So instead of connecting to the transmission network operated by the TSO, they are connected to the distribution network. This means different costs for the connection as distribution networks are on a smaller scale. The regulation stated that the renewable gas producer has to pay all the costs associated with connecting to the distribution grid. There is a pilot project to connect the first plant to the high pressure transmission network.

7.2.3. Quality assurance

The TSO and DSO are responsible by law for ensuring that the (natural) gas in the gas grid meets a certain standard, for safety issues. Each gas produced, by whatever source, has a slightly different concentration of the components and pressure. To be able to assure the quality of the gas in the grid, the quality of the gas injected has to be in a certain specification range. This is monitored at the injection point. If the gas does not meet the standard, it will not be injected into the gas grid. In all the European countries, the plant operator (supplier) is responsible for the quality of the gas injected into the grid. The odourisation of the gas is often also done at the point of injection. The responsibility most often lies with the producer, but this is not always clearly defined.

7.2.4. Other country specific cases

Alongside the above mentioned regulations, there are some country specific implications we briefly want to address.

In France, a draft law would include in the energy code a right to injection (*droit à l'injection*) for bio-methane into the natural gas grid. It states: "when a biogas production plant is located near a natural gas installation, the managers of the natural gas networks carry out the necessary



strengthening to allow injection into the networks of the biogas produced, under the conditions and limits defined by decree issued after the opinion of the Energy Regulatory Commission" (CRE, 2019). ". So, this right to injection makes it possible to connect sites that are outside gas service areas to the natural gas grid. In France, bio-methane has priority access in the grid. This means that if there is oversupply, the bio-methane producer is the last to stop injecting into the grid. In Italy, only bio-methane production via anaerobic digestion has access to the grid. Other sources are denied by law. This means that with the current regulation gasification of woody biomass does not have access to the national grid.

In the Netherlands, the TSO anticipates extra costs due to the use of renewable gases. As bio-methane production is constant over a year, while gas demand is highly seasonal, plus production is in rural areas while consumption is in urban areas, the grid operators (TSO and DNO) take measures to increase the buffering capacity within the grid:

- Storage before injection into the grid;
- Management of pressure within the grid (line pack);
- Integrating with demand by users in same part of the grid;
- Connections with other regional grids;
- Installation of boosters (compressor between the regional and the national grid).

The future extra costs for network operators are estimated at 0.006/m³, which will be socialised.

7.3. Assessment of regulation

Starting with the criterion that prices/tariffs should reflect marginal costs, the tariffs of using the natural gas grid should be based on the marginal costs. In addition, the network operator should also be able to recover the fixed costs, while the tariffs should not be higher than required for the network operator to break even. Moreover, in order to prevent the hold-up risk, the network operator should have certainty about how the investment in infrastructure will be remunerated once the infrastructure (e.g. connection to new gas facility) is realised.¹⁸

With the introduction of the separation of entry and exit capacity from the transmission tariffs in 2009 as well as the introduction of the reference pricing method in 2017, the European Commission is clearly pursuing the goal to reduce the impact of infrastructure bottlenecks on wholesale market trade and to give more certainty to both network operator and network users on the network tariffs. The problem of market power related to the natural monopoly character of networks is adequately addressed by the implementation of tariff regulation and unbundling. As pointed out in Chapter 4, third-party-access is crucial to foster competition. This is achieved by regulating the network operator and obliging the operator to facilitate a grid connection for gas suppliers. Information asymmetry is addressed by giving information about the availability and tariffs of transportation capacity. This is done through the new European regulation on the reference price method.

The above principles also apply to renewable gas. The conditions under which renewable gas facilities can inject their gas into the grid should be related to the marginal costs while the facilities should also contribute to covering the fixed costs. In order to be cost-effective, various production technologies should be treated according to these same economic principles.

¹⁸ From this follows that the regulator faces a dilemma when looking for the optimal tariff structure. In principle the tariffs should be related to the marginal costs, but then no network operator would invest anymore. Hence, tariffs should also give a compensation for the fixed costs in one way or the other.



However, renewable gas facilities can be given a discount on their contribution to the fixed costs of the gas network without distorting the market, although other network users have to pay more. This is, however, an issue of distribution of costs, not of efficiency of allocation, and hence, it may affect the fairness of the allocation of the fixed costs. If renewable gas producers receive such a discount, then this should be considered as production support (see Chapter 8). In addition, renewable gas facilities may be given priority access in case of congestion.

8. Support schemes

8.1. Introduction

The existence of barriers to entry related to the costs of development and production of renewable energy implies that the market cannot deliver the desired amount of renewable energy by itself. Support schemes for renewable energy are thus crucial to achieve the targets on the reduction of GHG emissions. As a matter of fact, the implementation of the Renewable Energy Directive and the (partial) achievement of the Member States' commitments on renewable energy consumption for 2020 outlined in their corresponding National Renewable Energy Action Plans has only been possible thanks to their support schemes.

Ultimately, the costs of the support schemes are paid by consumers. It is therefore important that while the renewable technologies are supported, they are supported to the minimum extent possible. In its general guidelines for the support schemes of Member States, the EU suggests that support should be limited to make renewables competitive in the market, should be flexible and adaptive to costs dynamics, should be clearly formulated, with fixed and understandable rules to create security for investors and should take into account that the market is European and not at the level of the Member countries, so the renewable potential of the neighbouring countries should be taken into account.

More concretely, though some exceptions are possible, in the most recent guidelines on state aid for energy and the environment of 2014, the European Commission puts forward a number of principles to be applied to the support schemes for renewable energies or cogeneration: the possibility of using feed-in tariffs to guarantee a remuneration for installations with a capacity under 500 kW, and the obligation to use a market-based mechanism for the determination of the compensation for installations with a capacity larger than 500 kW. The EC also requires the use of technology-neutral tenders for installations with a capacity larger than 1MW, as of January 1, 2017. These principles have been taken on board in the recast of the Renewable Energy Directive of 2018.

In line with these guidelines, four types of support schemes are used in the countries studied: feed-in tariffs (FITs), feed-in premia (FIPs), investment grants on the supply side and tax exemptions and obligations on the demand side.

8.2. Current situation

Different countries use distinct schemes to support renewable gases. As far as we know, hydrogen is not yet supported. The following table describes the current state of affairs for the countries studied.

Table 8.1 Support schemes of renewable gases for a number of European countries

		Italy	France	Germany	Belgium	Netherlands	UK
Supply	Feed-in tariffs (FITs)	yes	yes	yes	-	-	yes
	Feed-in premiums (FIPs)	yes	yes	yes	yes*	yes	-
	Investment grants	-	yes	yes	yes	-	-
Demand	Tax exemptions	-	-	-	-	yes	yes
	Obligations	-	yes	yes	yes	-	-

*: because certificates have fixed prices, de facto similar to FIPs

Source: CEER Status Review of Renewable Support Schemes in Europe

8.2.1. United Kingdom

The environmental programs of the UK government are administered by Ofgem. Currently, there are various schemes that provide direct or indirect support to renewable gases.

Feed-in-tariffs

The Feed-in-Tariff program is the main support mechanism for small-scale renewable electricity projects. Small installations using biogas to produce renewable electricity are eligible for the FIT Program. FIT support is granted for 20 years. Micro-CHP installations are also eligible, but the support is only payable for 10 years. The program, which was introduced in 2010, is meant to promote the adoption of small-scale renewable electricity generation technologies. Participant installations are assigned a tariff that depends on a number of factors, including technology, installed capacity and position in the deployment caps, which are limits on the total capacity that can receive a particular tariff rate in a particular tariff period. The program is financed by the (licensed) electricity suppliers, which are required to make payments to the eligible installations.

The FIT scheme provides support for biogas installations up to 5 MW that produce electricity. It does not provide support for installations producing heat, or bio-methane installations. These fall under a different scheme (details later). Applications for FITs are opened on a quarterly basis (for micro-CHPs, every six months). The last round was January-March 2019. The number of installations that receive support in a given period is limited since 2016 by the so-called 'deployment caps'. These caps are limitations on the total capacity that receive support in a given period. Tariffs have been declining over time. This is called 'degression.' As of March 2019, the FIT scheme is a three tier system. Installations with capacity up to 250 kW receive a feed-in-tariff of 4.50 p/kWh (approximately 5.2 €ct/kWh). Installations with capacity in the range 250-500 kW receive a FIT of 4.27 p/kWh (or 5 €ct/kWh). Installations with a capacity in between 500 and 5000



kWh are remunerated with 1.54 p/kWh (or 1.79 €ct/kWh). The 'degression' mechanism lowers the tariffs over time, in an attempt to keep with the cost developments. The degression is most noticeable every time the deployment cap is reached in a given quarter, in which case the FITs are decreased by 10% in addition to the usual period-related gradual adjustment.

Non-Domestic Renewable Heat Incentive

Support for the injection of bio-methane is provided by the Non-Domestic Renewable Heat Incentive (RHI) scheme. This program provides financial incentives for generating and making use of renewable heat. Biogas combustion for the generation of heat originating from anaerobic digestion, gasification or pyrolysis is eligible. CHP installations producing power and heat using biogas are also eligible for the heat produced. As mentioned above, the program also supports the injection of bio-methane into the gas network. In all cases, the raw materials for the production of biogas and bio-methane must meet certain sustainability requirements. For example, heat generated from landfill gas does not qualify.

The scheme provides payments for 20 years on the amount of heat generated, on a quarterly basis. The tariffs are set by the Department for Business, Energy and Industrial Strategy and the program is funded from general taxation. Tariffs are adjusted in line with inflation rates. The latest tariffs are for the quarter April-June 2019. For biogas combustion installation under 200 kW capacity, the tariff is 4.74 p/kWh (approximately 5.37 €ct/kWh). For installations in between 200 and 600 kW, the tariff is 3.72 p/kWh (approximately 4.21 €ct/kWh). Finally, larger installations with 600 kW or more of capacity are remunerated with 1.18 p/kWh (approximately 1.34 €ct/kWh).

For the injection of bio-methane there is a three tier system. On the first 40,000 MWh of eligible bio-methane, the tariff is 4.86 p/kWh (approximately 5.50 €ct /kWh); the next 40,000 MWh of eligible bio-methane are remunerated with 2.86 p/kWh (approximately 3.24 €ct/kWh); the remaining bio-methane receives a payment of 2.21 p/kWh (approximately 2.50 €ct/kWh).

The RHI has also a degression mechanism by which tariffs can be gradually adjusted downwards. The mechanism ensures that deployment pace is in line with expectations, and that the program remains affordable. If both the deployment rate and the expenditure are excessive, the degression mechanism implies a 20% cut in the tariffs for next quarter. If either the deployment rate or the expenditure are excessive, the cut is 10%.

8.2.2. The Netherlands

The Dutch government stimulates the production and consumption of renewable energy policy by subsidising deployment projects and reducing energy taxes. The current subsidisation program for renewable energy, dating from 2011, is called SDE+ (Stimulerend Duurzame Energieproductie +). This program succeeded the previous 2008-2010 SDE program, which was preceded by the MEP (Milieukwaliteit Elektriciteitsproductie) program. While the SDE program had dedicated budgets for particular technologies, the SDE+ program has a single budget and is thus meant to be technology-neutral. The goal of the SDE+ is to increase the share of renewable energy in final energy consumption using the most efficient technological option.

The idea of the SDE+ program is to compensate producers of renewable energy for the difference between the cost of production and the market price. The compensation is implemented via a Feed-in-Premium. This means that producers are also paid the going market price of the energy they produce. For 2019, there are two periods (Spring and Autumn) with separate budgets; for the



Spring period the government has allocated a total budget of 5 billion Euro. The subsidies are granted for 8, 12 or 15 years depending on the technology.

The SDE+ program is competitive, with the features of a tender. For every period, Spring or Autumn, there are three phases. Each phase has a maximum subsidy which applicants can apply for. This maximum subsidy depends on various factors including the technology, the feedstock and the size of the installation. Applications for lower subsidies are ranked first in the merit order and thus have a higher chance to get the funding; projects for which higher subsidies are necessary thus have a higher probability of being rationed. The maximum subsidy which applicants can solicit increases from phase to phase. However, the budget is fixed and phase 2 and 3 applicants run a higher risk not to receive any subsidy at all.

Biogas and bio-methane enter the subsidy category 'biomass'. In this category, subsidisation can be applied for all-purpose fermentation, mono-fermentation of manure, combustion of biomass, sewage treatment and gasification processes when renewable gas, heat or electricity are the end products. There are some sustainability criteria applied to the feedstock. The production of syngas is only subsidised if it is converted into methane and injected into the gas network.

Gas produced from the anaerobic digestion of biomass has a phase 1 maximum subsidy of 6.2 €/kWh, with a provisional correction of 1.9 €/kWh, which gives a final FIP of 4.3 €/kWh. Phase 2 and 3 maximum subsidies are the same. For the case of gas produced from the mono-fermentation of animal manure in installations smaller than 400kW capacity, the maximum subsidy in phase 1 is 6.2 €/kWh and increases to 7.8 €/kWh and 8.7 €/kWh in phases 2 and 3. For installations above 400kW capacity, the phase 2 and 3 maximum subsidy is 7.1 €/kWh. The maximum rate for biogas from sewage treatment is 4.8 €/kWh in all three phases.

For thermal gasification of biomass, the phase 1 maximum subsidy is 6.4 €/kWh, with a provisional correction of 1.9 €/kWh, which gives a final FIP of 4.5 €/kWh. This is applicable for 7500 hours a year and the subsidy is granted for 12 years. In phase 2 the maximum subsidy is 7.8 €/kWh while in phase 3 it is 8.6 €/kWh.

The Dutch policy also supports investment in renewable energy via tax reliefs: 40-42% of the investments can be deducted from corporate tax, which gives a net benefit of about 10%.

8.2.3. Belgium

Energy policy responsibility in Belgium is partly federal and partly regional. The existence of different regional regulations in Flanders, Wallonia, and Brussels makes it a relatively complicated model. Because biogas and bio-methane production occurs on a regional level, the regulation is regional. Regions support renewable energy and in particular biogas and bio-methane projects through green certificates and investment grants.

Support certificates

In the case of Flanders, there is a support certificate program (GSCs) that sustains biogas. Producers receive a support certificate for every MWh of electricity produced from renewable energy sources. Producers can sell the certificates either to electricity suppliers, or to traders. Electricity suppliers are subject to an annual certificate obligation, which creates demand for the certificates. In 2018, this quota was 21.5%. Support certificates can be used for the quota obligation during 10 years.

Alternatively, producers can sell their certificates to the network operators at a guaranteed price. The network operators sell the support certificates back to the market thereby recovering (part of) the costs incurred. The net costs (if any) are then socialised via the electricity bill. Missing a



certificate involves a penalty of €100 per certificate. Obviously, this penalty fixes the maximum willingness to pay for a certificate in the market. It turns out that the price of the green certificates has been constant for a long time. This makes the support system de facto similar to a feed-in-premium. Currently, the guaranteed price of the support certificates from biogas installations is 93 €/MWh.

Investment grants

The Flemish government also has two additional programs to support bio-methane by providing investment grants. One is the "Ecology Premium +" program, which provides support to standard technologies. The support partially covers the additional cost incurred by companies in undertaking 'ecological' projects. In particular, between 30-55% of the additional costs incurred by SMEs are eligible, and 15-45% in the case of large enterprises.

The other program is the "Strategic Ecology Support", which is intended for 'strategic' projects, that is, projects striving for generic environmental solutions. The grant covers from 20-40% of the additional cost of the essential components.

The Wallonian region has similar programs. Since 2004 there is a subsidy program that provides grants for up to 15% of the eligible investments by firms in biomass including biogas; this program also provides a property tax exemption. In addition, green certificates are used. The electricity system operator has a purchase obligation and the guaranteed price is €65; the certificates can also be sold in the market.

Both in Wallonia and Flanders, the support for renewable power plants except PV is 15 years. The support is funded in Belgium by levying charges to customers via the electricity bill (with energy-intensive industries partially exempted).

8.2.4. France

The French government supports renewable energy by means of FiTs for small and medium scale installations (under 500 kW), FiP for medium and large installations (over 500 kW), and tax deductions. The level of support for small installations is set by administrative procedures while that for medium and large installations is determined by competitive bidding. As mentioned above, France is the only country with a target for renewable gas in total gas consumption. France also has a special program to support bio-methane injected into the grid.

Feed-in tariffs

France promotes the production of electricity from certain renewable sources through a FIT. Eligible producers of renewable electricity receive a payment for the electricity they inject into the grid. Though EDF, suppliers and the distribution companies are obliged by law to buy the renewable electricity at the set prices, renewable electricity producers can sell their power to alternative retailers.

Biogas installations under 500 kW that produce the commodity through the methanation of non-hazardous waste and raw vegetable matter are eligible for FiTs. The current (2018) support for biogas plants with a capacity below 80 kW is 17,5 €/ct/kWh. Plants with a capacity equal to 500 kW are entitled to a FIT of 15 €/ct/kWh. For intermediate values of capacity, thus between 80 kW and



500 kW, the support tariff is calculated by linear interpolation. A bonus exists for biogas plants employing a share of at least 60% of livestock manure. This bonus amounts to 5 €/kWh. Biogas produced from urban and sewage waste is not subject to the capacity limit of 500 kW. Plants with a capacity above 1 MW are entitled to a tariff around 70 €/kWh. From 1 January 2018 onwards, the amount of the feed-in tariff is decreased by 0,5% on a quarterly basis. The support is granted for 20 years.

The costs of the program have been borne by the consumers of power via the electricity bill up to 2016. Since then, the program is funded directly by the State via a Trust Fund whose budget originates from general energy taxation.

Feed-in premia

Information on the outcome of the tenders is provided by the Energy Regulatory Commission (CRE). The January 2017 report provides results for three tenders for biogas plants with a capacity of 0.5, 1.2 and 3.6 MW. The average tariff was 18.5 €/kWh. The bonus for using 60% of livestock manure also applies here

Special support for bio-methane

The bio-methane sector benefits from two economic incentives: a regulated purchase price guaranteed for 15 years and a GOs system, which allows for traceability of the renewable gas and thus enables the producer to extract more value from consumers. Natural gas suppliers are obliged by the government to acquire the bio-methane at a pre-determined price.

The remuneration varies between 4.6 and 13.9 €/kWh and depends on the capacity of the installations, and the type of feedstock. For non-hazardous waste storage facilities with a capacity under approximately 500 kW, the tariff is 9.5 €/kWh, while for facilities greater than 3.5 MW the tariff is 4.5 €/kWh. For other capacities, linear interpolation is used. For other types of installations, the tariff is 9.5 €/kWh below 500 kW of capacity and decreases to 6.4€/kWh for installations above 3.5 MW. There is a premium for municipal waste and household waste that amounts to 0.5 €/kWh. There is also a premium for the use of intermediate crop products and waste or residues from agriculture, forestry, agribusiness or other agro-industries ranging from 3 €/kWh for small installations and 2 €/kWh for the larger ones. There is also a premium for wastewater treatment going from 3.9 €/kWh for small installations and 0.1 €/kWh for the larger ones.

Duration of the support

FIT and FiP contracts are granted for 10 to 20 years depending on the lifetime of the technology.

Investment aids

At present, investment aids are between 20% and 30% of capital costs.

Financing

Since January 2016, renewables support is financed from the general budget of the State.

8.2.5. Germany

Integration of renewable energy in Germany is facilitated by the Renewable Energy Sources Act 2017 (EEG 2017). According to its stipulations, the purpose of the Act is to increase the share of electricity generated from renewable energy sources to 40-45% by 2025, 55-60% by 2035 and to



more than 80% by 2050. Likewise, it is expected that the ambition for 2025 for the electricity sector will serve to reach a share of renewable energy in total energy consumption of 18% by 2020 as a by-product. The Act aims at facilitating energy supply to develop in harmony with the environment, thereby mitigating climate change. It is expected that the developments will take place gradually, keeping cost-efficiency and without putting pressure on the grid system.

Feed-in premia, or market premia

Producers of electricity from renewable sources that sell their electricity directly in the market are entitled to the so-called market premium. The market premium is determined by the Federal Network Agency in a series of auction procedures. Each type of renewable source of energy (wind, solar, biomass) competes in a separate auction.

In the case of biomass installations, which include installations in which electricity is produced from biogas, from 2017 to 2019 the yearly volume of installed capacity cannot exceed 150 MW. For the years 2020 to 2022, this volume increases to 200 MW. The volume beyond 2023 will be announced in due time.

New biomass installations must have at least 150 kW of capacity. Moreover, the proportion of cereal grain kernels and/or maize used to produce biogas must be at most 50% in 2017-18, 47% in 2019-2020 and 44% in 2021-2022. An installation's bid must specify value claims in cents per kWh. The Federal Network Agency sorts the bids in ascending order and awards the market premium to the lowest bidders. In 2017, the maximum bid was set to 14.88 €/kWh for installations with a capacity lower than 500 kW and 13.05 €/kWh for the rest of the installations up to 20 MW. Similar to the degression mechanism in the UK and Germany, this maximum bid decreases yearly by 1%. The premium is only paid for 50% of the bid quantity.

Feed-in tariffs

The EEG 2017 provides support for biogas produced from the anaerobic fermentation of biomass and bio-methane injected into the natural gas system. The support is provided to operators which produce electricity from those sources and feed it into the grid system and make it available to the network operator. The support is granted for 20 years.

50% of the power produced from biogas is entitled to financial support. For installations with a capacity below 500 kW, the FIT is 14.88 €/kWh. For installations up to 20 MW, the FIT is 13.05 €/kWh.

There are some special cases. Small biogas plants up to 75 kW that have at least 80% manure in their feedstock mix receive a FIT of 23.14 €/kWh. Landfill gas is remunerated with 5.66 - 8.17 €/kW for capacities below 75 kW and below 20MG, respectively. In the case of sewage gas, the FIT is 5.66 - 6.49 €/kWh for the same capacities.

The German system also has a degression mechanism. The mentioned FITs are reduced by 0,5 % per trimester after January 2018.

Investment aids

The KfW Renewable Energy Programme allows for the financing of the total investment costs, not exceeding €50 million, through advantageous loans at low interest rates. The support includes a repayment-free start-up period and (low-)interest rates are fixed for periods of 5 or 10 years.

Financing

The costs of the market premia and the FITs are borne by the final consumers.

8.2.6. Italy

In Italy, support for renewable energy is managed by the Gestore dei Servizi Energetici (GSE). From 2008 to 2012, biogas in Italy was supported by the “tariffa onnicomprensiva”, or “all-inclusive tariff”. This tariff was about 280 €/ct/kWh, the highest FIT in Europe for small (under 1 MW) biogas electricity plants using feedstock from agricultural products and energy crops. This policy changed in 2013, with an emphasis on using waste as feedstock, reducing the capacity of the biogas plants (under 600 kW) and incentivising the upgrading to bio-methane, especially in larger biogas installations. The biogas sector grew strongly during the 2008-2018 decade.

With the decree of March 2018, the Italian government further reinforces the position of bio-methane in the energy mix for the period 2018-2022. The decree allocates €4.7 billion to support biofuels and bio-methane intended for the transport sector.¹⁹ An important reason for this policy choice is that Italy, being the European leader in natural gas vehicles, currently has one of the most developed networks of gas refuelling stations. A second reason is that Italy currently falls short of its renewable targets for the transport sector.

The working of the program is similar to the earlier UK program on renewable obligations. The program distinguishes between bio-methane and advanced bio-methane, the latter referring to bio-methane from waste, and sustainable feedstock in general that does not cause any direct or indirect change in the use of land.

Bio-methane producers obtain from GSE a certificate called “Certificati di Immissione in Consumo di biocarburanti (CIC)” per 5.8 MWh of bio-methane injected into the grid. These certificates are in turn sold to the fuel suppliers, who are subject to a biofuel annual quota. In 2018, this quota was 7%, and further required 0.45% of bio-methane. In 2022, the quota will be 9%, and the bio-methane share 1.39%. Currently, the price per certificate is €375. The commodity can be sold directly in the market, or to the GSE, in which case the remuneration is based on the price in the spot market for gas minus 5%.

8.3. Assessment of Regulation

Our assessment and recommendations are guided by Table 4.1. In particular, we derive support levels taking into account economic efficiency and preventing windfall profits. Moreover, we suggest tenders with degression schemes as appropriate mechanisms to address dynamic efficiency, market power, information asymmetry and hold-up.

Table 8.2 summarises the current base support to bio-methane in the countries studied.

Table 8.2 Current support for bio-methane in selected European countries*

	FITs	FIPs	Duration support
UK	5.50 €/ct/MWh if V<40 GWh 3.24 €/ct/MWh if 40<V<80 GWh 2.50 €/ct/MWh if V>80 GWh		20 years
NLs		4.5 €/ct/kWh	12
BE		9,3 €/ct/kWh***	10
FR	9.5 €/ct/kWh for K<500 kW 4.5 €/ct/kWh for K>3.5 MW		10-20 years

¹⁹ https://europa.eu/rapid/press-release_IP-18-1441_en.htm

DE*	7.44 €ct/kWh for K<500kW	20 years
	6.5 €ct/kWh for 500kW<K<20 MW	
IT	6,46 €ct/kWh***	

V: volume; K: Capacity

*: We report the base support. For premia for specific feedstocks, see text.

**: In DE tariffs are only paid to 50% of the production (the reported tariffs are then adjusted correspondingly).

***: BE and IT remunerate the certificates; such systems are similar to FIPs.

Source: Authors' own elaboration

We assess the support schemes for renewable gases and hydrogen using the conceptual framework developed in Section 4. As we have discussed above, support for renewable energy should be, on the one hand, sufficient to compensate for the negative externalities generated by burning natural gas while, on the other hand, the support should not be higher than the actual extra costs of renewable gas production.

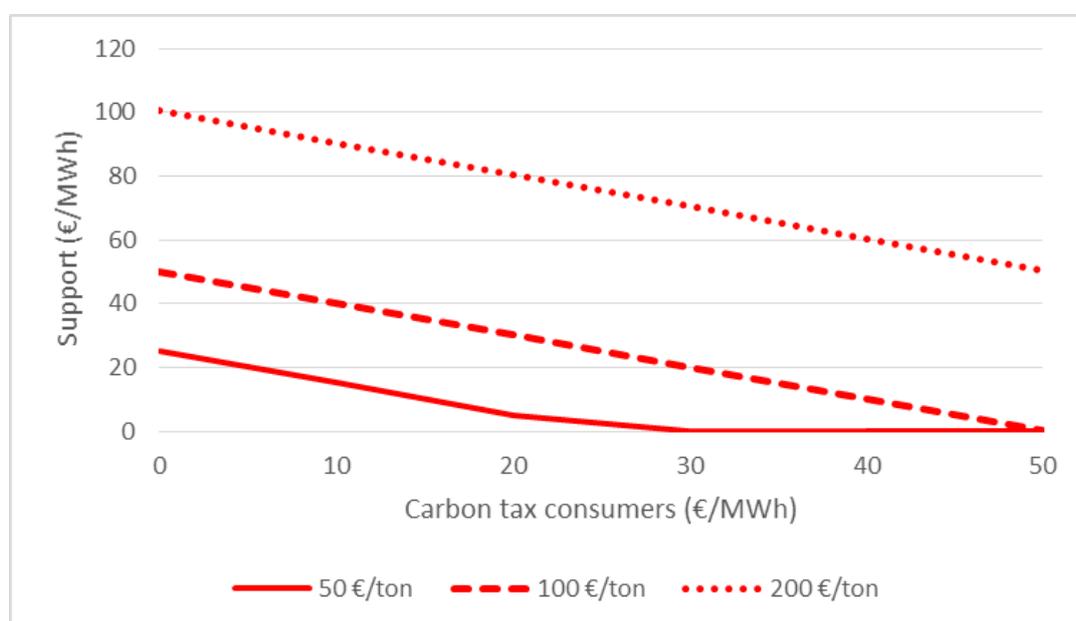
The first criterion refers to the allocative efficiency and is directed at repairing the market failure associated with the negative externality produced by the carbon emissions of natural gas. Before setting the support levels equal to the value of this externality one needs to control for the value of other regulatory measures which are also meant to internalise the externality. Here, in particular, we think of carbon taxes imposed on the consumption of natural gas. The existence of such a tax *de facto* raises the actual end-user price of gas, which gives environmentally conscious consumers incentives to opt for bio-methane. This increases the remuneration that renewable gas producers can receive for their GOs.²⁰ By this mechanism, it is expected that the price of certificates equals the carbon tax.

Hence, the optimal level of support from the perspective of allocative efficiency is a declining function of the carbon tax. The optimal support level also depends, of course, on the value of the negative externality generated by the carbon emissions. The economic literature gives a wide range of estimates for the damage costs of carbon emissions. Based on three estimates for the value of these damages (50, 100 and 200 €/ton of carbon), Figure 8.1 gives optimal support levels for renewable gas to internalise the pollution externality.²¹

²⁰ A precondition for the ability of green-gas producers to charge a higher price for the green certificates is that the carbon tax only holds for natural gas. If the carbon tax is just implemented on the basis of gas consumption, irrespective of whether consumers have obtained green certificates, the price of the certificates will remain the same. In that case the optimal support is equal to the value of the negative externality. For such situation, one can find the support levels by looking at the value of 0 for the carbon tax.

²¹ We note that 1 MWh of natural gas results in 0.5 ton of carbon emissions.

Figure 8.1 Optimal support levels for renewable gas based on allocative efficiency, in relation to the value of the negative externality of carbon emissions and carbon taxes paid by consumers



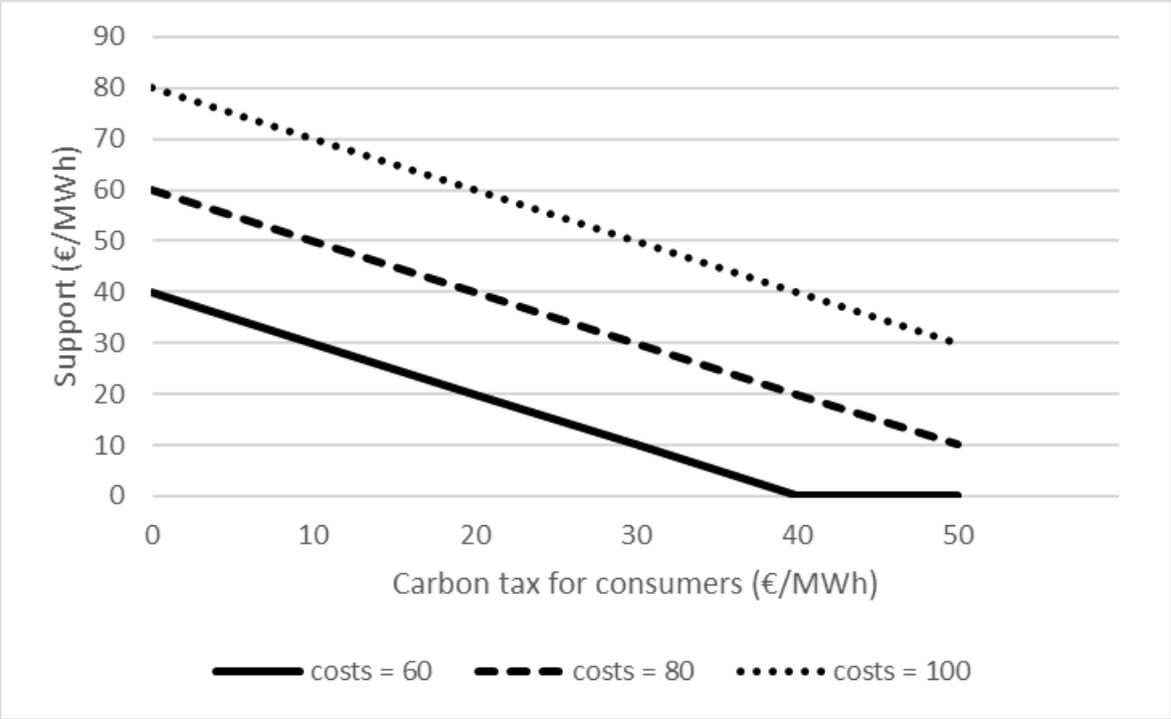
Source: Authors' own calculations

The second criterion is that the support levels should not result in windfall profits for the producers. Hence, the support should not be higher than that required to compensate for the extra costs incurred by renewable gas producers, that is, additional costs not compensated through other mechanisms. We call this criterion the *break-even constraint*, as the support should not be higher than the minimum necessary to make the projects break even.²²

We assume that the remuneration of a producer of renewable gas consists of a price for the methane (equal to the wholesale market price of natural gas, which has been 20 €/MWh on average over the past decade) and a price for the certificates. For the latter, we assume that higher end-user prices for consumers because of higher carbon taxes result in higher prices for the certificates. The maximum support level based on this criterion depends further on the actual costs of the various technologies. In Chapter 2, we concluded that the costs of thermal gasification vary between 44 and 52 €/MWh and the costs of anaerobic digestion between 2 and 200 €/MWh. Using three different cost levels for bio-methane, in particular 60, 80 and 100 €/MWh, Figure 8.2 presents the maximum support for renewable gas that results from the break-even constraint approach.

²² Note that we don't have the criterion that the support should be sufficient to make any green-gas project profitable as such a criterion would open the door for subsidizing loss-making projects.

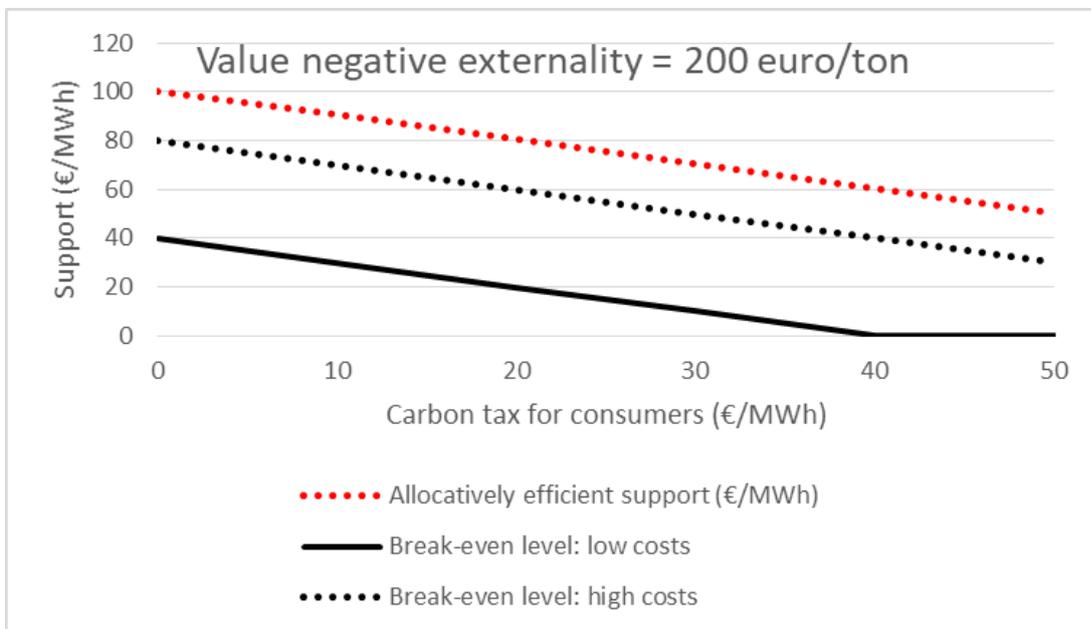
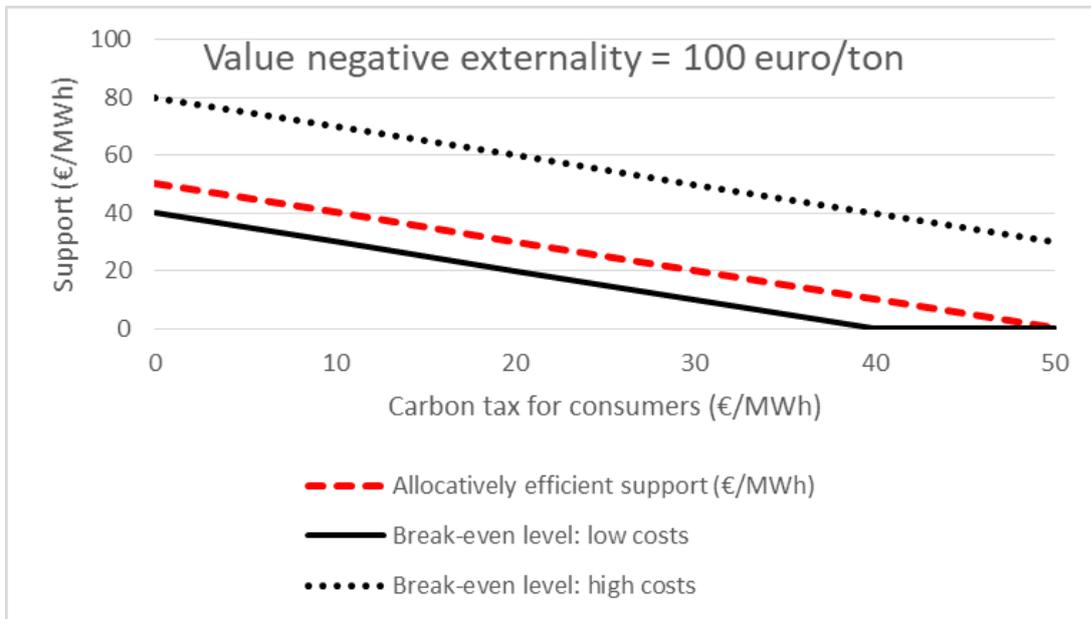
Figure 8.2 Maximum support levels for renewable gas based on the break-even constraint, for various levels of production costs and in relation to the value of carbon taxes to be paid by consumers



Source: Authors' own calculations

In Figure 8.3, we combine both criteria for deriving support levels (allocative efficiency and break-even constraint). We assume two different values for the negative externality of carbon emissions. If the damage costs of carbon emissions are estimated at 100 €/ton, then the allocative efficient levels of support are sufficient to compensate for the extra costs in the case of the least expensive technologies (i.e. gasification). More expensive technologies, however, cannot be sufficiently supported as the optimal level of support is below the level required to break even. When, instead, the damage costs of carbon emissions are estimated at 200 €/ton, then all technologies for the production of renewable gas can be more than sufficiently supported using support levels derived from the allocative efficiency criterion.

Figure 8.3 Optimal and maximum support levels for renewable gas, in relation to the carbon tax on consumers and the assumed value of the negative externality of CO₂ emissions



Source: Authors' own calculations

In conclusion, given our estimates of the costs in Chapter 2, if the damage costs of carbon emissions are estimated at 100 €/ton, and setting the carbon tax to zero, then the support levels for bio-methane should be around 50 €/MWh. If the carbon tax increases, support can be lowered. When positive externalities are present due to the special nature of feedstock, such as in the case of food waste, an additional premium ranging from 30 €/MWh to 130 €/MWh may be in order to allow these technologies to break even.



When the damage costs of carbon emissions are estimated at 200 €/ton, then the efficient levels of support suffice to make all renewable gas technologies profitable. Setting the carbon tax to zero, the support levels for bio-methane should be about 100 €/MWh.

Regarding hydrogen, using the same methodology as for bio-methane, we find that, if the social damages of carbon emissions are estimated at 100 €/ton, natural gas-sourced hydrogen can be supported with 40 €/MWh. With such an estimate for the social damage of carbon emissions, RE-sourced hydrogen could have a maximum level of support of 50 €/MWh, but this would still be insufficient for this technology to break-even. If the social damages of carbon emissions are instead estimated at €200/ton, RE-sourced hydrogen could have a maximum level of support of €8.5ct/kWh. Notice that if this cost goes down because of further subsidies to renewable generation, then the support should be reduced. Last but not least, producers of renewable electricity-sourced hydrogen should not pay energy taxes.

Another efficiency aspect that has to be considered is dynamic efficiency. Support schemes should also provide incentives to cut costs over time. The FiTs and FiPs programs of the UK and Germany have a 'degression' mechanism, that is, an automatic and gradual reduction of the support. France has a related approach to this issue by annually reducing the maximum bids firms are allowed to quote. As far as we know, Belgium and the Netherlands do not have degression mechanisms as such.

From the point of view of equity considerations, however, FiTs may be suboptimal because infra-marginal technologies may obtain too large a subsidy, leading to the well-known 'windfall profits'. In order to limit such windfall profits, the support systems of all the countries are tiered and have elements of competition. Typically, the remuneration of projects of larger scale and lesser operating costs is lower than that of smaller installations.

The problem of windfall profits is also due to the asymmetric information that exists between the regulator and the producers regarding the costs of their installations. This is easily resolved by introducing elements of competition. For example, the UK and Dutch programs have deployment caps and are phased. The UK has limits to the amount of capacity that is eligible for support, and once that capacity is reached the subsidy is cut by 20%. This is a way for the regulator to elicit cost information from the producers, which enables him/her to learn about cost dynamics and fine-tune the support over time. The Dutch system is somewhat different because the subsidy increases from phase to phase; however, because the budget is limited, producers do not have incentives to strategically wait to submit an application. France has a proper auction system, which is theoretically an efficient mechanism to allocate the support. A potential problem with using auctions is that there exists the possibility that producers collude, thereby undermining the entire support program. To avoid this, it is recommended using sealed-bid first-price auctions (ascending-bid and second-price auctions are more vulnerable to collusion, Marshall and Marx (2009)). Belgium does not have elements of competition in its system.

We have also mentioned above the inefficiencies that arise because of hold-up. To avoid that the government is held-up upon granting the subsidy, the regulations have stipulations indicating that the subsidy will be revoked if the installation does not come to the market in due time.

Certificates have been used to facilitate the monitoring of purchase obligations. Purchase obligations used to exist in the UK and currently exist in France, Belgium and Germany. To be effective they need to be linked to the existence of certificates. These obligations create scarcity and raise rents for the producers of renewable energy. Renewable obligations create demand for certificates. In Belgium, these certificates serve to organise the support for the producers of renewable gases. In other countries, the certificates are tradable and provide support indirectly.

We believe that issues of market power are not problematic as AD plants are typically small compared to the market and there has been sufficient entry.

9. Conclusions

This report explores the economic outlook for renewable gases and hydrogen and proposes a number of concrete regulatory measures to promote a cost-effective development of renewable gases and hydrogen markets in Europe.

In the first part of the report, an economic assessment of the costs of production for each type of renewable gas and hydrogen is conducted. The main findings are:

- 1. Anaerobic digestion is a mature technology for the production of biogas.** Typical plant size is approximately 4 MW. Biogas produced from anaerobic digestion can be upgraded to the specifications of natural-gas and so directly injected into the grid. Upgrading typically occurs in separate units. Several inputs can be fed into the digesters, most commonly, biological waste and animal manure. As a result, feedstock is mainly local and therefore the variable costs of anaerobic digestion are particularly sensitive to local feedstock availability and its prices. Ignoring sewage sludge as feedstock, due to its high management cost, the **break-even price for bio-methane produced from the anaerobic digestion of animal manure, food waste and energy crops, including upgrading and injection, ranges between 5 and 200 €/MWh**. This cost can be as low as 5€/MWh when biogas producers use a single feedstock and receive payments for collecting such specific feedstock, as is the case in the Netherlands for pig and poultry manure.
- 2. Thermal gasification is an alternative technology for the production of biogas.** This technology, which is still under development, shows a larger potential for scale economies. Plant size is expected to reach 1 GW and the upgrading from biogas to bio-methane for injection can be performed within the same production unit. Thermal gasification employs dry biomass (forestry products and residual waste) as main inputs. Therefore, its costs are not as dependent on the local availability of feedstock as those of anaerobic digestion. **The break-even price of bio-methane obtained from gasification is between 44 and 52 €/MWh.**
- 3. The other gas analysed in this report is hydrogen.** That analysis is limited to hydrogen produced with renewable electricity, in the case of electrolysis, and with Carbon Capture Storage (CCS), in the case of Steam Methane Reforming. The costs of hydrogen production are thus highly dependent on the prices of electricity and natural gas, as well as the prices of green certificates in the case of electrolysis and the cost of CCS in the case of Steam Methane Reforming. **Given current prices, the break-even price of natural gas-sourced and renewable-sourced hydrogen is around 40 and 85 €/MWh, respectively.**

Based on those figures, **the report concludes that the current production costs of the various renewable gases and hydrogen range from 2 to 5 times the current price of natural gas in the wholesale market. This implies that in the absence of adequate carbon pricing or support, it is very unlikely that renewable gases and hydrogen will enter the market.**



In addition to the costs of production, the report analyses the current production and the production potential of renewable gases and hydrogen. The key findings are:

1. Total bio-methane production in the EU-28 was 1.94 bcm (approximately 19 TWh) in 2017, which amounted to about 0.8% of the total natural gas production in the same region and year (247 bcm). European hydrogen production in 2015 was 7 Mtons/year (approximately 270 TWh and 25 bcm natural gas equivalent), which was about 5% of total natural gas consumption in the EU in the same year (487 bcm). However, the long-run potential of these gases is quite significant. For a group of selected representative EU countries, namely Belgium, France, Germany, Italy, the Netherlands and the United Kingdom, we estimate that bio-methane production from anaerobic digestion can easily reach 37 bcm per year. For the same countries, the potential for bio-methane production from gasification is approximately 38 bcm. Together, we estimate an annual potential of 75 bcm for these countries, which is about 20% of their current gas consumption. Considering Europe as a whole, the same methodology results in a total potential of 124 bcm of bio-methane for EU-28, which is about 25% of current gas consumption in the same region.
2. The potential of both renewable electricity-sourced and natural gas-sourced hydrogen is very hard to estimate. Given that the inputs for the production of hydrogen are natural gas and electricity, theoretically speaking, the potential supply is very large. However, in practice, the potential of renewable electricity-sourced hydrogen depends on the availability of excess renewable power, which currently is very scarce and could remain scarce as sectors such as heating and transport switch from fossil fuels to electricity. An important potential limitation for RE-sourced hydrogen is the tension with climate policy: electrolysis plants need a low price for renewable electricity in order to be competitive, while producers of renewable electricity need high prices to recoup their investments. A strong climate policy implies a high carbon price, which, in turn, will raise the price of electricity and will limit the competitiveness of RE-sourced H₂. According to Navigant (2019), the supply of renewable electricity-sourced hydrogen from excess electricity in Europe could reach 200 TWh (18 bcm) by 2050; this potential could be much higher using dedicated wind and solar resources as well as electricity imports from regions outside the European Union. The potential of natural gas-sourced hydrogen is quite large, conditional on the social acceptability of CO₂ storage. Finally, a significant deployment of hydrogen requires substantial investments in infrastructure (retrofitting the existing natural gas grid or deploying a new grid) and final appliances (such as the adaptation of boiler burners).

In the second part of the report, the objective is to understand what the optimal regulation of the markets for renewable gases and hydrogen should be. The economic regulation of renewable gases and hydrogen should improve their position in the gas market, if their current position is unfavourable due to market failures. In order to realise their potential and maximise the EU's plans to decarbonise the energy system, the study confirms that specific regulatory measures are greatly needed.



The report stresses that the main steps and pillars to design a proper framework are to define policy targets, to make the supply of renewable gas traceable through the creation of schemes for green certificates, and to give producers access to the gas infrastructure. Although renewable gas is traceable and can be injected into the grid, producers may still find it difficult to compete on the market because of the relatively high costs. **Therefore, a regulatory framework should include additional measures such as the creation of production support schemes and instruments to foster demand for renewable gas, for instance by imposing renewable gas obligations on retailers.**

Building on these factors, the study concludes that:

1. The European Union should set EU-wide targets for 2030 and 2050 for the gradual replacement of natural gas and non-carbon-neutral hydrogen.

- a) This study has identified a potential to supply 75 bcm of bio-methane annually for the six countries analysed and 124 bcm for the EU-28. Assuming a constant level of demand, **we thus recommend an EU-28 target of 10% of bio-methane for 2030, and a target of 25% by 2050** (Figure 5.1). However, if gas demand significantly declines in the EU-28 after 2030, the 2050 target should be adjusted accordingly. For example, if gas demand is expected to fall by 30%, the suggested target for 2050 should be 35%; if demand instead is expected to fall sharply by 50%, this target should be set at approximately 50%.
- b) **A new legislative proposal should also consider an assessment of EU-wide and national market progress by 2028**, against the 2030 targets. A report explaining the main developments of the renewable gases markets should help to better enforce targets from 2030-2050. Such progress reports should guide the European Commission to review and make recommendations per Member State in the design and submission of National Energy and Climate Plans.
- c) We expect renewable electricity to remain scarce in the future, due to economic factors, implying that there will be few hours with low electricity prices. **Therefore, we believe that the bulk of hydrogen in 2050 will be natural gas-sourced using SMR combined with CCS.** Conditional on the public acceptance of CCS, the production of NG-sourced H₂ is not really constrained. Therefore, **we propose a target of 100% of carbon-neutral hydrogen by 2050.** We also strongly believe that such a target will act as an instrument to foster the social acceptance of CCS. **There is no need to impose a specific target for RE-sourced hydrogen, as it is implied by the availability of electricity, which has its own target at the EU-level.**

2. A fundamental condition for the functioning of the market for renewable gas is the traceability of the commodity via a certification system. In order to improve the functioning of the current certificate schemes we recommend the following measures:

- a) Further integration of the national systems by setting EU standards for renewable gases and hydrogen, which should facilitate further development of these markets.
- b) Ensure that the certificates released by different EU Member States, according to the same EU standard, are interchangeable. Interchangeability should also be ensured between different energy vectors (electricity and gas) in a sector coupling perspective.
- c) Increase the role of public authorities in the certification process as this fosters the trust of market players in the system.

- d) Ensure the compatibility of the ETS system with certificates, to improve the market value of certificates. This would make it possible to use the carbon reduction of renewable gases to meet obligations within the ETS.
- e) Improve the transparency of systems for certificates, including how they are organised and how market parties can trade, which will give the scheme further impetus.
- f) Reconsider the need for the mass-balancing approach (in which the international trade of GOs certificates is connected to the physical trade) and the possibility to move more strongly in the direction of a full book-and-claim approach as the mass-balancing system limits market liquidity, although it may help to improve transparency.

3. The economic principles for allocating the costs of network usage apply to renewable gas producers. The conditions under which renewable gas facilities can inject their gas into the grid should be related to the marginal costs, while the facilities should also contribute to covering the fixed costs. **Renewable gas facilities can be given a discount on their contribution to the fixed costs of the gas network without distorting the market,** although other network users have to pay more. This is, however, an issue of distribution of costs, not of efficiency of allocation. If renewable gas producers receive such a discount, then this should be taken into account in the production support. **In addition, renewable gas facilities may be given priority access in case of congestion.**

4. Given the negative externalities of the consumption of natural gas, support schemes should be introduced in order to overcome this market failure. The optimal value of the support depends on the value of the negative externality of carbon emissions on the one hand and, on the other, the value of other regulatory measures to internalise this externality.

- a) If the social damages of carbon emissions are estimated at 100 €/ton, then the allocative efficient levels of support are sufficient to compensate for the extra costs of the least expensive technologies (i.e. thermal gasification). More expensive technologies, however, cannot be sufficiently supported as the efficient level of support falls short of the break-even level of support. Given our estimates of the costs and our assumption which sets the carbon tax to zero, the support levels for bio-methane should be around 50 €/MWh. When positive externalities are present due to the special nature of the feedstock, such as in the case of food waste, an additional premium ranging from 30 €/MWh to 130 €/MWh may be in order to allow these technologies to break even.
- b) When the external damages of carbon emissions are estimated at 200 €/ton, then the efficient levels of support suffice to make all renewable gas technologies profitable. Again, if assuming the carbon tax is zero, the support levels for bio-methane should be about 100 €/MWh.
- c) Current levels of support in the countries under consideration are roughly in line with our independent recommendations. We additionally advise renewable gas consumption to be exempted from the tax on the consumption of gas, which will increase remuneration for renewable gas certificates and boost incentives to expand renewable gas production.
- d) To the best of our knowledge, there are currently no support schemes for hydrogen. Using the same methodology as for bio-methane we find that, if the social damages of carbon emissions are estimated at €100/ton, natural gas-sourced hydrogen can be supported with 40 €/MWh. With such an estimate for the social damage of carbon emissions, RE-sourced hydrogen could have a maximum level of support of 50 €/MWh, but this would still be insufficient for this technology to break-even. If the social damages of carbon emissions



are instead estimated at 200 €/ton, RE-sourced hydrogen could have a maximum level of support of 85 €/MWh. Of course, producers of renewable electricity-sourced hydrogen should not pay energy taxes.

- e) Support schemes should be designed to be competitive, typically based on tenders, and should move dynamically to match cost developments. This can be done by incorporating 'degression' mechanisms as in the United Kingdom, fixed budget lines as in the Netherlands or declining reserve bids as in France. Support should be provided for a sufficiently long period of time to provide investors with the necessary incentives to participate. The EU should identify best practices and eventually introduce EU-harmonised rules for the allocation of support.

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Chapter 7:

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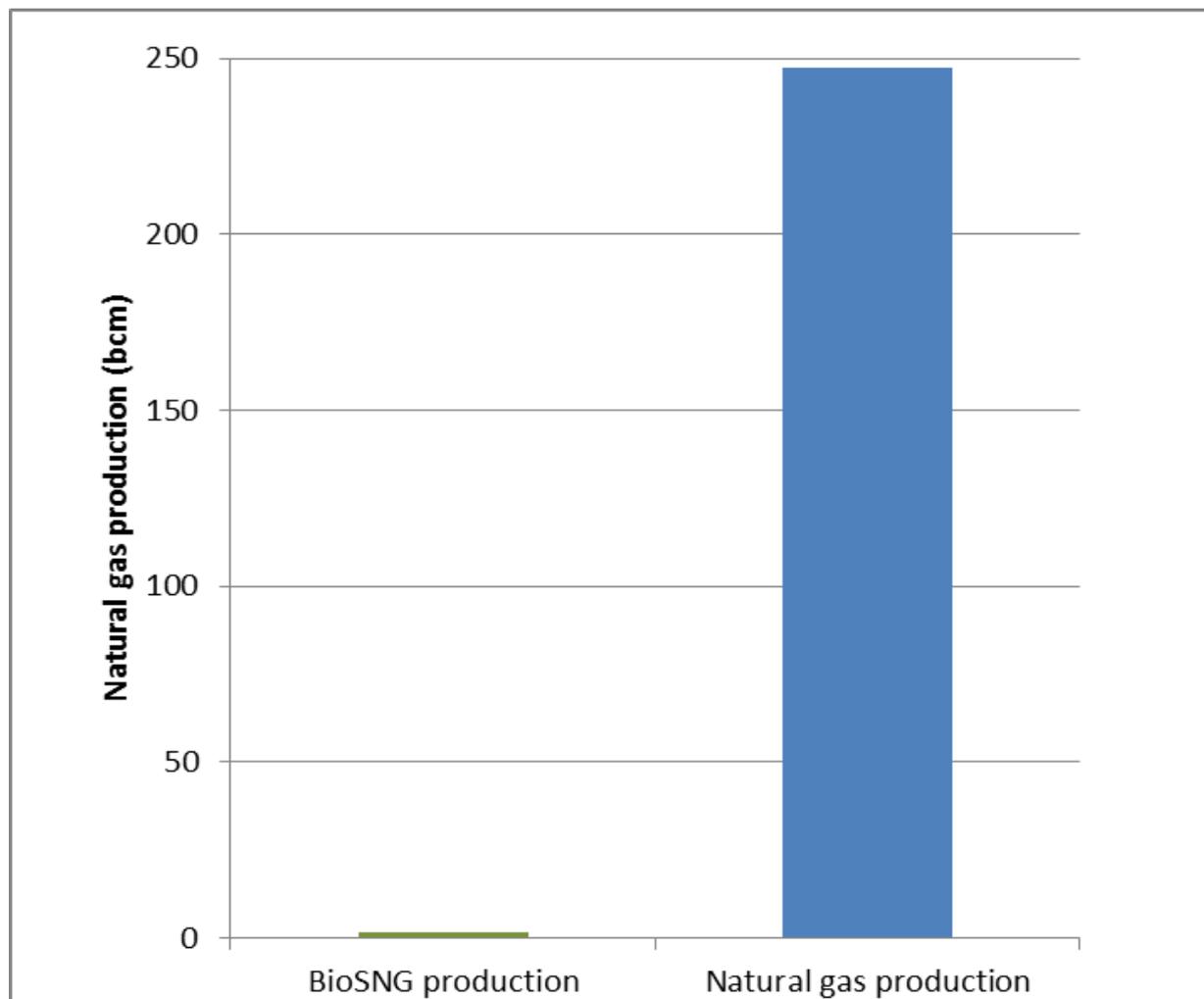
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Appendix

Figure A.1 Bio-methane production compared to natural gas production, in EU- 28, in 2016





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